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Decarbonization of the electricity industry – is there still a place for markets?

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Introduction

The core issue addressed in this report is how to decarbonize the electricity sector. The motivation for the report is that virtually full decarbonization of electricity is necessary in order to achieve the economy-wide targets that are specified by UK legislation and by European Union (EU) policy commitments – at least 80 per cent reductions in CO_2 or CO_2[1] equivalent emissions compared to 1990 levels. Very few governments are aware of, and none have yet successfully resolved, the many policy issues that electricity sector decarbonization raises. This report discusses some of the key challenges and analyses different ways of addressing them.

A central question is: whether electricity markets, as currently organized and structured in the EU, are capable of, or compatible with, efficient delivery of the policy-determined objectives for emissions reduction and the necessary contribution of the power sector to that reduction. This report describes a number of distinctly different, though not necessarily mutually exclusive, approaches to the question. Some may simply involve modifications to existing market structures, within EU markets at very different stages in the market liberalization process. Others involve direct government intervention either through mandating additional targets or more direct involvement in the investment process.

The report is designed to stimulate discussion rather than to put forward any single solution. The authors have approached the issue of decarbonization with a view to arguing the case for a number of very different approaches to policy. The strength of the arguments for and against particular options will reflect country and regional differences, including variation in the points of departure, current carbon intensity of the sector, urgency and scale of investment required, and interdependence with surrounding countries.

On the other hand, all countries are likely to share certain common features that will characterize the possible routes to decarbonization, notably the need to rethink wholesale and retail markets to reflect the growing importance of low-carbon generation

[1] Throughout this paper we will tend to use the terms carbon and CO_2 interchangeably, largely reflecting common usage.

(usually with very low marginal costs and with output that is either inflexible or intermittent) and of new forms of demand-side participation, assisted by the development of the smart grid.

The starting point for the report (Part 1) is an introduction to the importance of electricity to the decarbonization agenda. Part 2 analyses the Electricity Market Reforms (EMR) being introduced in the UK. These reforms are widely seen as a watershed for the sector, involving a substantial shift from a 'pure' liberalized market model to one requiring more centralized direction. Since the UK has been a leading proponent of a decentralized model relying heavily on competition in energy-only markets to drive investment, and the UK has also adopted a very ambitious decarbonization agenda, it is a particularly interesting case. The EMR process has established the basis for a debate about the combination of measures needed to deliver electricity decarbonization.

Part 2 argues that the most important factor underpinning the EMR proposals is the belief that there is a requirement for long-term agreements of a contractual nature, with a reliable counterparty, to provide incentives for low-carbon investment. This points strongly to the need for more central direction and coordination; Part 2 explores how different forms of central agency might be established, while retaining as many as possible of the benefits of competition and market discipline.

Subsequent sections explore different approaches to decarbonization. Part 3 analyses ways of encouraging efficient investment in low-carbon technologies without the need for direct government underwriting of particular contracts. In particular, it introduces the idea of carbon intensity targets that would encourage generation companies to develop and implement low-carbon technologies in order to reduce their carbon intensity over a long period. If adopted, this approach could replace many of the technology-specific programmes sponsored by governments, and might make unnecessary a range of other regulations, such as the development of capacity markets.

Part 4 analyses ways in which existing energy, capacity, and CO_2 markets might be reformed and extended to meet the challenges of decarbonization, following a

decentralized model rather than a centralized one. It calls for more and better markets, rather than more government intervention, to address the decarbonization challenges.

Part 5, which concentrates on the demand side of the market, applies equally to centralized models (like the EMR analysed in Part 2) and to the more decentralized ones described in Parts 3 and 4. It explains the changing role of demand response in a decarbonized market and the role that smart grids, smart meters, distributed generation, and electric vehicles will enable customers to play.

Part 6 identifies and analyses the key issues that policy makers in all countries will have to address, and potentially steer, if they are committed to decarbonization. It argues that, while there may be varieties of approach to decarbonizing the electricity sector, there are some major common policy issues that require a rethink of the planning, operations, organization, regulation, and financing of the sector. Furthermore, even though countries may follow different paths, these issues will have to be addressed together, within the EU's legislative framework.

We hope that this document will serve as a basis for facilitating the policy debate within individual countries, across the EU, and further afield.

Part 1 The central role of the power sector

Electricity as the key vector in a low-carbon economy

The central role of electricity in relation to CO_2 emissions is a common feature in both developed and developing economies. In Europe, the European Commission's *Roadmap for moving to a competitive low-carbon economy in 2050* (EC 2011, 6) sets out a plan to meet the long-term target of reducing domestic emissions of CO_2 or CO_2-equivalent by 80 to 95 per cent by mid-century, as agreed by European Heads of State and Governments. The Commission notes that:

> Electricity will play a central role in the low carbon economy. The analysis shows that it can almost totally eliminate CO_2 emissions by 2050, and offers the prospect of partially replacing fossil fuels in transport and heating. Although electricity will increasingly be used in these 2 sectors, electricity consumption overall would only have to continue to increase at historic growth rates, thanks to continuous improvements in efficiency. The share of low carbon technologies in the electricity mix is estimated to increase from around 45% today to around 60% in 2020, including through meeting the renewable energy target, to 75 to 80% in 2030, and nearly 100% in 2050.

The Commission's approach is broadly similar to that adopted in the UK, where the Climate Change Committee saw decarbonization of electricity as one of the first and most important areas. It concluded that 'Any path to an 80% reduction by 2050 requires that electricity generation is almost totally decarbonized by 2030' (CCC 2008, 173) and this is at the heart of the UK government's strategy.

The power sector itself constitutes the largest single source of UK CO_2 emissions, accounting for about one third of the total. Moreover the second largest source of CO_2 emissions is the transport sector, currently dominated by road transport, where the most promising alternatives to fossil fuel use are currently electric vehicles, or, just possibly, fuel cell-powered vehicles using hydrogen (which similarly relies on a primary electricity source). The third largest source of emissions is fossil fuels used to heat buildings – where various forms of both conventional electric heating and more novel technologies, such as air- or ground-source heat pumps, again provide significant

potential for emissions reduction. Of course, electrification of transport and heating will only contribute to the reduction of CO_2 emissions if the electricity is from low-carbon sources.

For the UK, the early achievement of a largely decarbonized power sector is a necessary condition for the achievement of ambitious emission-reduction targets. Although not a wholly sufficient condition for meeting the targets, the single measure of decarbonizing an expanded power sector could in principle permit achievement of two-thirds or more of the emissions reduction required by 2050.

This importance of electricity in energy demand is matched on the supply side. Most of the main primary energy alternatives to fossil fuel burning, such as nuclear power and most renewable sources, lend themselves to electricity as an efficient, and often as the only practical, vector for delivering low-carbon energy to the point of use.

Finally, the location and network-specific nature of power generation means that many policy measures for the electricity sector are more directly within the control of national governments than is the case for some other sectors, such as manufacturing, where technology and other policy choices are set within a context of international business and trade.

Potential market failures in relation to low-carbon objectives and the power sector

Until recently, there has been an implicit, and sometimes even an explicit, assumption in government climate change policy[2] that markets would play the major or leading role in the delivery of emissions targets. While few would dispute the value of markets in energy policy in general, and their potential value in driving efficient solutions to environmental problems, this assumption deserves critical review.

The case for careful analysis is, to paraphrase the Stern Review (Stern, 2006), the observation that the link between emissions and climate change constitutes 'perhaps the biggest market failure the world has ever seen'. Since the problem starts with an

[2] See, for example, DTI (2007).

identification of market failure (in other words, a failure to provide the efficiencies and socially optimal outcomes that should flow from a functioning competitive market) then market solutions need to address existing market imperfections and avoid creating new distortions, as well as confronting Stern's core externality of climate change.

This implies careful examination of all policy instruments in relation to electricity markets, to deal with the risks of additional or accentuated market failure arising from possible flaws that are already present in those markets, as well as the emissions externality per se. Governments have played a major role in setting up both the market structures and the regulatory policies and mechanisms that currently define electricity markets. Given the growing national and global importance of action on emissions, it is clear that government oversight of markets and regulatory policies is needed, to obtain assurance that they are meeting, and will continue to meet, fundamental policy objectives.

This systemic concern with energy issues has some powerful analogies with the well-established necessity for the oversight of financial markets and their regulation – these include the fundamental economic importance of the sector, and the potential for conflict between individual private and corporate interests and systemic stability or sustainability. If markets do not meet society's needs, or are vulnerable to systemic failure, for whatever reason, then attention turns either to reform of the market and its institutions, or to the alternative policy instruments of regulation and direct intervention. We will argue that there are particular features of the power sector that render it vulnerable to market failures, and show the need for vigilance on the adequacy of its market and regulatory structures.

The natural first step in response to the challenge of emissions-induced climate change, as argued by Stern, is a market approach to internalize the costs of emissions, whether through appropriately designed methods and levels of taxation or through the development of emissions trading within an overall emissions limit – the EU ETS (Emissions Trading Scheme) currently being the prime manifestation of this second approach. This reinforces the importance of examining the adequacy both of this trading scheme and of the existing electricity market structures within which it operates.

Using the UK case for illustration, we address the general question of why governments have been reluctant to employ a textbook 'first best' approach, which would identify one of the following as a theoretically optimal approach to policy:

- A carbon tax that correctly reflects the 'social cost of emissions', that is, the estimated cost of the damage that they cause through their impact on future climate; **or**
- A quantity limit for cumulative emissions, which arguably should be weighted according to the date of the emission; this is then shared out through a market in tradable permits. The limit, in principle, represents a calculated optimal feasible level that can be achieved.

Estimates of the social cost or the optimal quantity limit are both difficult and contentious, but in a theoretical textbook world, with no uncertainty and perfect foreknowledge, and subject to a number of qualifying assumptions, one would expect the approaches to be broadly equivalent, and to provide an optimal policy outcome. The right level of carbon tax/price would result in the optimum quantity of cumulative emissions, and vice versa.

Quite apart from the substantial practical issues of resolving what is the right estimate of social cost or the optimal quantity target, however, there are further major problems for governments in either version of these 'purely market driven' textbook approaches to policy. Even if there were universal acceptance of a 'moderately high' cost of carbon – such as figures around the £56 per tonne of CO_2 that are to be found in the current Treasury/DECC guidance for policy evaluation (Treasury, 2011) – the imposition of such a tax on emissions would have immediate political, sectoral, and distributional consequences that most governments are not currently prepared to contemplate. The same qualifications apply to any quantity-limit scheme which imposes severe limits and has a similar effect on consumer prices.

The most significant of the adverse features of such a purely market-driven approach, from any government perspective, are as follows.

First, it will typically be the case that many of the necessary investments can be induced by offering a much lower price than £56 per tonne, and are profitable at much lower

prices (even if these are a little higher than current prices). Moreover, the higher price, if available to everyone, will benefit investments that have already been made, such as those in existing nuclear plant and some less carbon-intensive gas plant. This will mean high levels of windfall profits to some producers; these profits will derive from much higher revenues paid by consumers. On the other hand, many of the investments seen by governments as necessary (for example offshore wind generation) are unlikely to be profitable, even with a £56 carbon price, and will not therefore take place, so the government cannot rely on the price alone to deliver either its emissions or its technology targets.

In contrast, direct government intervention in various guises can be used to discriminate along the supply curve and minimize the extra profits accruing to low-cost producers, including existing nuclear and gas producers. Discrimination can be achieved, for example, by limiting the benefits to new plant, and providing financial or other support only for quotas of particular technology types, while still in principle encouraging competition among suppliers to meet those quotas. This may be construed as unhelpful intervention in technology choice, but it is easy to understand why it is an attractive option for governments. It provides a significant means of limiting both windfall profits and the overall cost to government or consumer. It also enables governments to pursue industrial and national security policies that favour the development of specific low-carbon technologies that probably would not be developed without explicit government support.

The second general concern for government is implicit in the above, and is the political impact of the significantly higher consumer prices which would result from the purist textbook approach. This runs the risk of undermining political support for the whole emissions-reduction programme.

The third problem is the intrinsically global nature of the issue. The cost–benefit trade-offs implied in the textbook, market driven, approach outlined above are by their nature global in scope. The estimated social cost in this context is an aggregate global cost. But this is not a benefit that accrues to UK citizens as compensation for foregoing their own consumption, or for investing in emissions reduction. Costs and benefits, from a UK perspective, quickly become asymmetric, as consumers bear the whole of the cost but

perhaps get back (even in the long term) only 2 per cent of the benefits. This, particularly in the absence of effective global agreements, strongly reinforces an unwillingness to use either a social cost or a purely market-driven approach as a basis for pricing emissions.

These considerations broadly explain a strong political preference for direct interventions. These may be 'second best' in a theoretical sense but will have the desired effect of reducing emissions without some of the pain of major price adjustments. Possible interventions include a range of measures of a regulatory nature and measures to support innovation (including innovation in particular technologies). (Quantity-limits or taxes could also be part of the package as supporting measures, rather than the sole instrument for meeting the declared emissions targets.)

We can categorize the range of plausible interventions, including both the UK's current EMR proposals **and** the variants and alternatives we explore in this chapter, in terms of the ways in which they attempt to deal with the conundrum of this inability to allow an 'unconstrained' purely market-driven approach. The categories are not necessarily mutually exclusive, and indeed it is possible that the best policies may require a combination of approaches. They are as follows:

- Limited adoption of the pure market or CO_2 emission **price driven approach**, typically through much more limited CO_2 emission price rises or less demanding quantity restrictions.
- **Mandating** low-carbon out-turns by imposition of low-carbon requirements on the retail supply businesses, on generators or on vertically integrated utilities, or through other direct interventions to bring about new low-carbon capacity.
- **Reform** of wholesale electricity market structures through specific measures such as capacity payments or markets for ancillary services.

Price driven approaches The EU ETS is an example of limited adoption of a market-driven approach, but it has shown substantial practical weaknesses. First, it has been set with very limited ambition on carbon emission limits, and in consequence has failed to deliver carbon prices that are sufficiently high to provide a commercial case for the level of low-carbon investment that is acknowledged as necessary. Second, both the volatility of prices (especially in response to economic cycles), and the relatively short

duration of the scheme, undermine confidence in its ability to support revenues over the long term. The EMR proposal for a carbon price floor is another example of this approach, but it needs to be understood in the context of the EMR proposals as a whole.[3] More generally, CO_2 emission prices should always be seen as having an important role to play, even if, as we argue, the high price levels necessary to achieve the policy aims, without additional measures, appear not to be a feasible option.

Mandating change This includes those policy interventions which leave individual market players to work out how best to achieve the mandated outcome. In our study we discuss two particular interventions that both work essentially by mandating an outcome. These are the carbon intensity obligation discussed in Part 3 and a development from the EMR proposals that would mandate a single buyer, discussed in Part 2. The Californian approach is based on mandating vertically integrated utilities. The UK's own renewable obligations are also a form of mandating, in this case for retail companies. Designing an effective mandatory approach will imply considering what market and incentive structures the approach creates.

Reforming market structures Wholesale electricity market structures can have a significant effect on prices and on investment prospects, even in the absence of low-carbon policy imperatives. But these market structures will also need to change to reflect the technical realities and opportunities facing power systems operating with low-carbon generation. We have identified some of these issues in relation to capacity payments and ancillary services, as well as in relation to demand-side measures. We have also discussed reforms to the EU ETS market and to other European incentives for promoting specific low-carbon technologies. Again, the detail of the markets and the corresponding incentive structures will be important for the efficacy of the reform. These issues are discussed in Parts 4 and 5.

The central question is whether energy and CO_2 markets, as currently organized and structured in the UK and in the rest of the EU, are capable of, or are compatible with, the efficient delivery of large emission reduction targets over ambitious timescales, and with the degree of urgency that these targets imply. Specific proposed measures within

[3] The price floor on its own would be unlikely to demonstrate adequate regulatory commitment.

all three of the above categories can be considered and evaluated for their general efficacy, for the extent to which they can meet the specific requirements of the power sector and for infrastructure investment, and for the extent to which they can be developed in ways which encourage competitive pressures to deliver lower-cost solutions.

The UK EMR set in this context

The proposals for UK electricity market reform include elements of all three of the approaches we have outlined. In summary, the EMR has four main components:

- A proposed floor price for carbon (a price-driven approach);
- Market reforms which would lead to capacity payments to enhance prices in what is currently an 'energy only' market (market structure reform);
- Restrictions on the carbon emissions of any new generating capacity (mandatory/interventionist);
- A proposal for feed-in tariffs which would take the form of plant-specific contracts for differences (CfDs) which would apply over a long period (mandatory/interventionist).

Our general reaction to the proposals (in which we are largely in line with David Newbery – Newbery, 2012) is that there are strong arguments for substantial reforms and that these will necessarily move, to some degree, towards greater central direction and coordination, and away from the purity of the current British liberalized market model. This does not necessarily have to undermine liberalized markets fundamentally – the extent to which the reforms have a negative impact on competitive pressures will depend on the particular measures chosen, and the context in which they are introduced. The devil is in the detail.

At the time of writing many aspects of the EMR proposals are still subject to detailed consideration and discussion. However, reliance solely on a carbon floor price (the first element of the proposals) is unlikely to be sufficient, for the reasons discussed above. It is also arguable that reforms to the market structure, such as the introduction of capacity payments (the second element) may indeed be necessary, though it is less clear whether they are sufficient. It has been cogently argued that such reforms would have been

necessary, even in the absence of a low-carbon policy imperative, in order to remedy the deficiencies of an 'energy only' market. The issues involved are considered in Part 4.

Intrinsically, simple quantity limits, imposed on individual plant (the third element in the proposals) run the risk of any arbitrary regulatory intervention of this type – in other words, of introducing inefficiencies. In practice, it is possible that if other elements of the EMR policy are successful, and adequate incentives are in place to create new low-carbon capacity, then statutory limitations on the construction and operation of plant with high carbon emissions should be redundant.

The proposal for feed-in tariffs (the fourth element) has been seen by many commentators as the cornerstone of EMR, as well as potentially the most controversial aspect. The description 'feed-in tariffs' may be to some extent misleading, as the proposal is couched in the language of long-term contracts (though this may not be their final legal form), which may be plant-specific and may be awarded after competitive tender. Much of the important detail remains to be settled, not least the question of who will be the counterparty to the contracts.

There are differing views about how problematic the feed-in tariff element of the proposals will be and how far it represents excessive government intervention in the market. The following parts of this study look at alternatives to the EMR proposals; Part 2 can be interpreted as the development of the FIT element of the EMR proposals in a coherent manner, emphasizing the requirement for some agency for central coordination and decision making. Parts 3 and 4 introduce more radical options, which might be considered by those who consider the degree of intervention implied by the EMR proposals to be unnecessary and potentially distorting. Parts 5 and 6 look at some wider issues which will need to be considered whatever approach is taken to stimulating low-carbon investments.

Part 2: Developing the case for central direction and coordination

Introduction

This part develops the case for more central coordination and direction, and suggests how it might be introduced while retaining many, if not most, of the benefits of competition. The arguments deployed in this section are of general applicability, but have taken on particular significance in the UK due to the current debate over electricity market reform. The EMR proposals are widely regarded as marking a move towards more central guidance. In the proposals set out below we consider one route by which more efficient central direction could be achieved, through the development of a central agency, while retaining as many of the benefits of competition as possible. In the UK this would imply more explicit recognition that the proposed EMR reforms were moving in the direction of such an agency.

Three major institutional themes, related to industry structure, governance, and the design of markets, are relevant to this argument. All three need consideration in pursuing reforms that will take us successfully and efficiently to a low-carbon economy.

Investment

The first and most important issue – given both the scale of the transformation that is required and the aging nature of the capital stock, particularly evident in the UK – is investment. The volume of investment required now outstrips the balance sheet capacities even of the largest vertically integrated utilities (as further discussed in Part 3).

Investors in a capital intensive, long life, immobile, and highly use-specific asset – a term which describes most low-carbon and indeed most traditional generation investments – require adequate security in the revenue stream, and protection from

those regulatory or other market risks which are outside their control. These include the risk that other parties, including the government or regulatory agency, will at some future time introduce measures or take actions which lead to a surplus of capacity and undermine the wholesale price assumptions, and hence the projected revenues, on which the investment would have been predicated in the first place. A second risk is that even under conditions of capacity shortage, price controls will be imposed, so that the higher prices which might have been expected, in a free market, to compensate for periods of low prices and capacity surplus, will not materialize.

This issue for investors is sometimes described as one of **regulatory commitment**, and is separate from, or additional to, the relatively simple issue of the signals provided by market prices. This is a longstanding issue for the power sector, and explains why the 'natural' development of the sector in most countries has been, and in many countries continues to be, through vertically integrated monopoly, often under municipal or state ownership. Its importance is reinforced by the huge volume of investment now required to meet the decarbonization targets of countries such as the UK. This means that even vertically integrated utilities will need to rely on infrastructure investors, such as pension funds and sovereign wealth funds, in order to generate the financing required. These are investors who may generally be seeking only modest rates of return, but will demand a high degree of security attaching to their investment. They have a particularly important role under current conditions of cash-strapped governments and the high levels of investment necessary for power sector decarbonization.

Particular factors that can exacerbate this problem, in the context of policies requiring low-carbon investment, are the additional difficulties in making that investment appear attractive relative to coal- or gas-based generation. These include 'incumbent advantage',[4] where volatility in fossil fuel prices induces corresponding volatility in the wholesale electricity price, at least for as long as the system is dominated by fossil plant operating at the margins. Fossil generators' profit streams are to some degree insulated from this volatility, since their input costs will be highly correlated with the market prices achieved for their output. Low-carbon generators will not enjoy this advantage,

[4] See Anderson (2007).

and as a consequence they will suffer more volatile revenues, making them less attractive investments.

The investment problem for low carbon is accentuated when the mechanism (such as EU ETS) intended to deliver the main carbon price signal, on the attractiveness of low-carbon investment, has proven to be so weak as to fail to generate the expectation of emissions prices anywhere near high enough to make the investment attractive. Even if actual or expected carbon prices were higher, the absence of clear regulatory commitment to high long-term carbon prices reinforces the problem for investment. The uncertainties perceived by potential investors have been compounded by the weaknesses of the EU ETS, its relatively short-term horizons, very low carbon prices (induced in part by the economic recession), and by the failure thus far to establish a credible set of EU policy and regulatory commitments in relation to a carbon price.

In the UK, these considerations may now have become so serious, partly as result of policy uncertainties, as to imply very high levels of government commitment and underwriting of risks, as a necessary condition for almost any power sector investment.

The investment issue is undoubtedly the prime cause underpinning the perceived need for fundamental reform of the electricity market structure in the UK. But two other important issues are also relevant, in the UK and elsewhere.

Wholesale market

The second theme relates to the fact that the existing wholesale market structures in Britain, and indeed throughout much of the EU, were designed largely by the owners of fossil generating plant to suit the technical, cost, and operating characteristics of that plant. With the advent of large volumes of zero marginal cost plant (a significant part of which may be intermittent or inflexible, or have other characteristics very different from conventional thermal plant) these market structures will necessarily require very substantial revision. Other countries with substantial amounts of renewable energy, such as Spain, Denmark, and Germany, are already experiencing and dealing with the problems of zero marginal costs, leading to zero or even negative prices. However, the wider problem of requiring multi-period optimization (for inflexible plant or 'storable'

demand) has received less attention. The processes of short-term system control and optimization, and of wholesale price formation (and very specifically the intimate connection between the two) as they have operated for the last two decades, may prove to be unsustainable.

This is a more technical issue, and has a rather longer fuse, since it will become serious only as low-carbon generation, and new kinds of non-instantaneous (or time-moveable) consumer demand, start to impact in a major way on wholesale prices and on system operation. Nevertheless, it would seem foolish to embark on major reforms without some credible view of how this issue might be resolved. Part 6 and its Annexes look at these issues in a little more detail.

Even within the present rules, an additional source of wholesale market problems arises with any failure to price CO_2 emissions properly, and to take account of their very large externalities. This failure is evident whether one considers the issue in relation to the actual externality of climate change or to the prices needed to achieve meaningful emissions reductions through cap-and-trade schemes. Such a failure necessarily implies that the wholesale electricity markets will not deliver outcomes that are compatible with welfare maximization or with efficient achievement of emissions policy objectives. It will, for example, inhibit gas-for-coal substitution when this is one of the least cost and easily achieved means of achieving emissions reductions.

Coordination

The third theme is that the management of such a huge transformation of the power sector, and its substantial expansion to accommodate transport sector load, will pose some very demanding issues for coordination of generation investment in relation to infrastructure. Such infrastructure includes conventional transmission infrastructure, CO_2 gathering networks for Carbon Capture and Storage (CCS) plant, and the development of smart grids to accommodate and complement demand-side measures. In addition, with the potentially more complex operational characteristics of low-carbon plant, there will be a need to ensure a compatible balance of different types of intermittent and inflexible plant, and a balance with 'smart grid' and future demand

patterns (especially in transport). The International Energy Agency (IEA) has argued that this is more easily achieved within vertically integrated systems.

This issue has not been recognized as one of the prime drivers for policies on electricity market reform (EMR). But it does pertain to a large number of current issues and policies for the sector, including offshore wind development, CCS, and smart grids and metering. It would therefore be foolish not to consider coordination questions in the context of EMR.

We recognize that all three of these themes are, to some degree, at odds with the belief that, in the absence of any statutory obligation on suppliers to meet emissions objectives or provide adequate capacity, a viable and efficient power sector response to emissions policy targets will nevertheless emerge. Moreover, the three themes appear to cast doubt on the delivery of adequate low-carbon generation investment in this environment by a competitive market lacking long-term contractual structures, and responding only to 'spot market' or other wholesale price signals and expectations.

Basic Proposition: Managing Central Direction

The proposal here starts from the recognition described above that there are a number of market failures implicit in meeting the low-carbon policy objective, which stem from the interaction of:

- the difficulties encountered in internalizing the costs of emissions in decisions made by the main parties in the power sector, either via a cap-and-trade or an estimated social cost approach; and
- issues intrinsic to the power sector, including those of coordination, but more importantly the need for regulatory certainty as a basis for investment.

In this proposition we recognize explicitly that our diagnosis of the problem provides some strong arguments for a greater degree of central direction and coordination, as an alternative to increasingly complex and frustrating attempts to manipulate or reform the market to achieve an outcome (a low-carbon economy) that is intended to be policy determined. In the UK, this diagnosis is implicit in much of the EMR consultation.

Our general proposition can also be treated as a natural, or even a necessary, concomitant of one of the main measures (perhaps the crucial measure) proposed in the UK electricity market reform proposals – the idea of feed-in tariffs based on contracts for differences. It has been suggested that these will be long-term in character, may be specific to individual type and vintage of plant, and may be awarded after competitive tender. In these respects, the proposed arrangements have all the essential characteristics of long-term contracts. However this proposal raises the question of who will be responsible for the award of these contracts, and who will be the counterparties to them.

The general proposition here – one which sits naturally in the context of current UK EMR but has yet to be adopted there – is therefore for a **central agency** to take responsibility for delivering both the low-carbon emissions target and a sufficiency of total generating capacity and associated transmission, purchasing from multiple generators and selling on power to suppliers. In effect the agency performs a critical part of the traditional role of a vertically integrated utility. It may also be described as a single buyer,[5] but, as the discussion makes clear, alternative variants of the model allow for greater or lesser degrees of central or government control. The key factor is the reliability of the agency as a counterparty to long-term contracts.

This resolves our three earlier investment and coordination issues as follows:

- The central agency enjoys the downstream security of revenues, ultimately from its own monopoly or near monopoly position, and the market strength of retail suppliers whose needs it is contracted to supply. This enables it to offer 'bankable' long-term contracts to low-carbon generation investors; the viability of these contracts is not dependent on a highly uncertain carbon price. The outcomes include a lower cost of capital as well as greater attractiveness to the community of infrastructure investors.
- The contracts can, if necessary, be framed as power purchase agreements, and include provision for the central agency, or the system operator, to dispatch output as required, subject only to the constraints, commitments, and rewards/penalties set out in the contract. The agency can therefore, if necessary,

[5] We generally avoid the term 'single buyer' simply because the term has acquired a huge emotional baggage in association with vertically integrated state monopolies. There are a variety of ways in which this model can be developed or refined to allow more or fewer degrees of control to the agency itself.

and through the system operator, optimize generation over much longer periods – such as a month, or even a year. This resolves the wholesale market issues arising from a low-carbon system where simple merit order stacking is no longer possible or appropriate. In other words, it provides a structure within which the optimization of more complex 'low carbon' system operations can take place.

- It can also deal with the broader coordination issues in a simple and straightforward way, negotiating directly with the National Grid (although one of the options below is for the grid to take on the agency role) or with suppliers and local networks. Many of the coordination issues – such as selection of a technically compatible mix of plant types – can be handled within the central agency itself. The model also offers a variety of ways in which the central agency/supplier/customer interface can be managed to accommodate demand response, and an undiminished role for distributed generation and local networks.

This leads on to the question of how a central agency might operate and how it might interact with existing market structures, and incorporate some of the EMR proposals on contracting through suitably framed CfDs. The concept of a central agency per se is not new, and is a familiar option in electricity systems where a 'fully competitive' wholesale market-based model is ruled out either on practical grounds (such as small systems, human resources limitations) or because fully liberalized markets are deemed to leave governments with an inadequate set of policy instruments. In the current context in the UK, the relevant policy instruments are required for low-carbon and generation-security objectives that the government does not think that a fully competitive market will achieve.

Simply in terms of market mechanics, a central purchasing approach can be designed to include most, if not all, the beneficial competitive pressures and market disciplines associated with the best features of the 'fully competitive' UK model. Early versions of the 1990 England and Wales privatization model, promoted by the regional supply and distribution companies in the industry negotiations but discarded in order to enhance full retail supply competition, were in effect based on the notion of a single buyer function exercised jointly by the 12 distribution companies. Under this scheme the 12

would have forecast their own requirements and made separate contracting choices before pooling their contracts for operational purposes. One proposed scheme, the distributors' pool, would then have had the National Grid dispatching generation plant under contract.

An alternative, much closer to the solution finally adopted, was based on a 'generators' pool'; this was intended to allow generators to collectively meet their contracted commitments by trading through an actual or bid based (as opposed to contractual) merit order so as to maximize efficiency. The latter was eventually modified in relatively minor ways to create the actual 1990 market structure, inter alia by formally ensuring the pool was open to a wider range of participants (buyers/suppliers as well as generators). However, the essential point is that core features of the wholesale market or merit order pricing structures of a competitive market, to incentivize efficient operations, would or could transfer to an institutional framework built around a central agency.

In a closely related and equally interesting parallel, given some of the issues and possible solutions now emerging in relation to electricity markets, it may also be recalled that the National Grid was initially established in 1990 under the joint ownership of the 12 distribution companies.

The concepts of central purchasing and organization have not therefore been totally foreign to the development of the UK model of competitive industry structure. The following section describes in a little more detail some of the options for the way in which a future central agency might work. Discussion or consideration of these alternatives has to be linked to consideration of other questions – such as the intended extent of direct government intervention in the sector, whether to promote particular low-carbon technologies, or to encourage more or less decentralization of decision making in the sector. It starts from the recognition that the sector must tackle three main obstacles to achieving a timely and efficient low-carbon sector – investor confidence, wholesale market reforms and infrastructure coordination, and the conviction that some form of central intervention and coordination is a necessary feature of any market reform strategy.

Details of a Central Agency Proposal

There are, in institutional terms, several options for structuring a central agency that differ from the EdF model of state ownership. These include joint ownership by suppliers, which could be combined with the imposition of individual and collective obligations on supply businesses to source low-carbon generation (as discussed in Part 3). This would imply the companies were collaborating to find the least-cost solution to decarbonization investment, allowing them to achieve the scale economies that may be very important for some of the prospective technologies.

Another option would be to assign the agency role to the independent system operator or transmission operator (in the UK this would be the National Grid). This combination of roles would also help to resolve the wholesale market operation and coordination issues outlined above.

There are thus two main alternatives for the commercial arrangements pertaining. Under the first, the buyer's minimum responsibilities would be confined to dealing with power purchase agreements and bulk supply tariffs or other contractual means by which suppliers purchase power. This would apply only to new low-carbon plant connected to the main transmission grid. It would operate under guidelines from government, regulator, or a committee of major retail suppliers. The retail suppliers would individually retain responsibility for forecasting total requirements, which could be expressed through contracts nominating both the supplier's energy and capacity requirements.

Under the second, the agency would assume responsibility for placing contracts with both new and existing plant, both low-carbon and fossil. It would have well-defined duties to ensure sufficient capacity, to meet the anticipated demands of the suppliers, and to meet carbon objectives.

Although the agency might quickly become the main body responsible for contracting for new capacity, a number of exceptions can be envisaged. First its monopoly could be qualified, for example by allowing large industrial consumers to be supplied by independent generators (also subject to a carbon emissions restriction). 'Embedded

generation' not connected to the main grid could also contract directly with retail suppliers, and would be taken into account in their contracting with the agency. This would further reduce or remove any residual risk of the agency ignoring or discriminating against decentralized generating options.

Similarly there are two main alternatives for the means by which the central agency would pass on the costs of the investment it acquired to utilities, and hence ultimately to consumers. The agency could purchase power either on its own responsibility or in response to capacity and energy contracts placed, as 'orders', by downstream electricity suppliers. This would lead, on one model, to the agency selling power onwards under a multi-part bulk supply tariff. Charges would reflect the costs of supply, differentiated by the time of day and season of the year, and would almost certainly include charging for capacity as well as marginal costs of energy at different times.[6]

Alternative models would make the central agency operate essentially as an agent in the contracts, which would be shared out among suppliers according to the quantities they had contracted. Both models could be consistent with obliging the supply companies to make forecasts of their own requirements and contract for them – sometimes known as a 'contracted capacity' approach.

Meeting future challenges

It has been suggested that a central agency would not place sufficient emphasis on important and potentially less centralized initiatives and future developments – such as smart metering and demand-side management. As an objection this would carry more weight if the existing structures of retail competition had delivered effectively, or at all, on this front. Arguably the form of competition introduced in the UK, with its load profiling that removed any potential incentives for consumer response, stifled developments which were already at an advanced stage in the 1980s, such as the 'Peddie' meter (Rosenfeld et al., 1986) – the name refers to an Area Board chairman who championed smart metering developments at that time.

[6] In these respects, but perhaps only these respects, it would resemble the old CEGB bulk supply tariff.

Nevertheless this is a legitimate criterion to apply to the proposal. There are in any event questions around whether effective demand management is best organized through central mechanisms, particularly for large loads such as storage heating and battery charging, or through decentralized approaches, including direct customer access to the wholesale market.[7] Discussion and identification of some of the relevant issues are continued in Part 5.

It can be argued that, in comparison with current structures, the impact of a central agency per se would be broadly neutral, since the role of introducing demand-side initiatives to consumers would still be carried primarily by the suppliers. Getting the right cost signals into this process might be associated with a well-defined and cost-reflective bulk supply tariff, or with the alternative option where the suppliers operate with the contracts allocated to them.

Similar arguments apply to the question of distributed generation. Future systems may well combine large-scale and remote generation, connected to the high-voltage transmission network, with a much greater number of small-scale generation facilities within decentralized local networks and connected at lower voltages. While it is possible to exaggerate the likely scale of the latter,[8] the institutional framework needs to accommodate them. Distributed generation is strongly analogous to demand-side management (if seen as negative demand), and poses very similar practical and commercial issues. It can be argued that the prime responsibility for encouraging and managing distributed generation will remain with the downstream retail suppliers, and that the critical factors will be the adequacy of bulk supply tariffs or contractual arrangements in transmitting cost and price signals both for longer term decisions, and for very short-term decisions that are related to the deployment of operating reserves to respond to intermittent renewables and other changes in system supply and demand.

It can be argued that a central agency is well placed to adapt to whatever combination of models emerges. Some parties have argued that coordination within a vertically integrated utility, rather than unbundled and fully liberalized atomized markets,

[7] Subject to caveats about how future wholesale markets will operate with a preponderance of low-carbon plant.

[8] The main front-runners as major contributors to low-carbon generation remain nuclear, offshore wind, and CCS plant, none of which are immediately or obviously conducive to decentralized operation.

provides a much more effective means to introduce demand-side measures. For example, the IEA argues that 'unbundling also makes it difficult to capture both costs and benefits of various technology deployments on a system-wide basis – especially with respect to smart grids.' (IEA 2011c)

Policy Issues

One of the major concerns with a central agency model is that it represents a return to an era of centralized decision taking where strategic decisions are no longer left to the private sector and the competitive market.

It is possible to argue that centralized decision taking is a necessary outcome of some of the problems identified elsewhere, and that a complex non-fossil generation mix requires the imposition of constraints on what proportions of plant are technically compatible. However, it is also possible to argue that, even with a central agency, many if not most of the decisions, particularly on the quantity and the specific mix of plant to build, can be pushed back to the major electricity suppliers, who choose how much to contract from the central agency, most obviously so under the 'contracted capacity' approach.

One concern is that a central buyer would get tied in with well-established technology options. This would have the effect of shutting down innovation and new technologies, and would additionally operate against the interests of decentralized options. On the other hand, it can be noted that firms would still be competing to supply the central agency. Generating plant is a highly competitive international industry, where the degree of that competition is unlikely to be inhibited by decisions taken in one national market.

It could also be argued that this danger applies equally within existing structures, with potentially cosy oligopolies such as the Big Six in the UK. By contrast a central agency would almost certainly have to demonstrate to its regulatory body or sponsoring ministry that it **was** exploring all the most economic options, and seeking competitive tenders when appropriate. The central agency would not own significant generation assets, so it would not have a direct vested interest and, prima facie, its duties to secure

the most efficient and economic means of meeting security and low-carbon obligations should give it an incentive to welcome innovation.

There is another broader issue that is often discussed in this context. It is the fundamental question of how risks should be carried within utilities and infrastructure industries. It may be argued that a central agency would become a de facto regulated monopoly which effectively transferred risk from investors to consumers or taxpayers, and that this should be seen as a disadvantage.

It is important that the sector's structure, regulation, and contracts allow other more controllable risks to be managed as efficiently as possible. This means that where risks can be reduced and controlled by good management, they should be placed with the party best equipped to manage them, and this should be reflected in the incentive structures built into contracts and other commercial arrangements.

However, irreducible commercial risks in the sector, outside the control of the main actors, do not go away because they are born by investors; the latter typically charge a risk premium, or require a higher rate of return on capital to cover the risks they face. So in the end the cost of irreducible intrinsic risk within the sector will end up with the consumer by one route or another, except in circumstances where some third party, such as government, is willing to cover it. For the irreducible elements of risk which can be deemed to be outside the control of any of the actors (such as oil prices) either investors will charge a premium on the cost of capital, the cost of which will pass through to consumers, or a regulated pass-through of costs will allow a lower cost of capital to be charged. There is a strong case (Green, 2003) that the latter approach is more efficient and will result in a lower cost of capital and lower prices.

This is especially important in the context of current prospects for the power sector, and is very evident in the UK. The most credible source for the volume of funds required for the huge volume of necessary infrastructure investment will be investment funds, such as pension and sovereign wealth funds, which are prepared to accept relatively modest returns, but are extremely risk averse. This is an environment where governments are very likely to be pulled into underwriting contracts and regulatory commitments, and

where a central agency provides one of the means to increase regulatory certainty and investor confidence.

Part 3: Investment signals for low-carbon generation: a carbon intensity scheme

Introduction

The proposal in this part of the study starts from the observation that electricity market reform for decarbonization covers two periods where separate problems are faced: the transition phase – market structures aimed at securing investment in low-carbon generation; and the prospective scheme – market structures to promote the efficient and effective operation of a low-carbon system. The latter issue, looked at in Part 5 of this study, has tended to receive less attention. This is understandable, given the scale of the challenge involved in the transition itself, but it is worth starting with a reminder of these future operational issues. It is important that the reforms adopted in order to promote low-carbon generation do not turn out to be ill-designed for the eventual goal of an efficiently operating low-carbon system. It is arguable that a centralized system might help avoid such conflicts by enabling a single operator, with an overview of the whole system, to take an integrated approach. On the other hand, a centralized approach entails the risks of lack of innovation, inflexibility, and over-prescriptiveness. Those who wish to avoid those risks might therefore wish to consider the simpler option proposed in this part of the study, which is designed to create an overall framework for low-carbon investment rather than to prescribe the nature of that investment.

The scale of the investment need

As Part 1 of this study indicates, achieving governments' decarbonization objectives necessitates the promotion of low-carbon investment. Within any electricity system there is of course some flexibility of operation and it is possible to give signals to encourage the preferential use of the low-carbon sources available. But this flexibility is inevitably constrained by the capacity in place, because of the familiar characteristics of an electricity system: demand has to be met at all times; there are few practical options for large-scale storage; imports are constrained both by infrastructure and availability; capacity is long-lived and capacity development has long lead times. So in practice the

nature of the capacity in the system largely determines the carbon intensity of generation.

In the case of the United Kingdom, carbon intensity will have to decrease at a rate unprecedented in UK history (though there are precedents for rapid decarbonization, such as France in the 1980s,). The government's objective, set out in the White Paper *Planning our electric future* (HMG 2011a), is not specifically stated but is equivalent to around 100g/kWh, which compares with a figure today of around 480g/kWh (IEA 2011b). To get to a figure below 100g means building some 60GW or more of capacity compatible with a low-carbon target (as compared with a total system today of around 90GW). Capacity of 20–30GW will need to be built simply to replace plant due to retire over the period. Most of the rest will be needed specifically to reduce carbon intensity and meet the UK's renewables target for 2020 from the EU's 20/20/20 package. While the renewables target, at 15 per cent, may sound modest, it applies to energy as a whole. Since renewable sources are likely to be concentrated mainly in electricity, the implication is that over 30 per cent of electricity will have to come from renewables by 2020. The majority of that renewable fleet will be wind generation, operating at a load factor of 30–40 per cent at best, so this implies that 40GW or more of renewable capacity will be needed (compared with around 6GW today); it also means that there will have to be an increase in total system capacity, even without any growth in demand.

Market signals for low-carbon investment – drawbacks of the EMR approach

New capacity will therefore need to be built at a rate unprecedented in UK history. The overall amount of investment required is estimated by the government at around £110 billion, which would require at least a doubling of the current rate of investment (HMG 2011a).[9] The question is how to give signals for such investment within a liberalized market, where no generator is required to invest at all, much less invest in a particular

[9] This estimate has recently been challenged – the Chief Executive of SSE is quoted in *Power in Europe* 25 June 2012 as saying that only £70–75 billion would be needed and that existing mechanisms could deliver this. But this only adds to the uncertainties policy makers are facing. £70 billion would still be a significant increase on current investment levels; furthermore, the uncertainties that led to the lower investment estimate (lower electricity demand, shale gas potential, nuclear extensions, etc.) are likely to encourage investors to hold back or invest in gas-fired generation, rather than investing in expensive low-carbon capacity, accentuating what is already a problem with liberalized markets, as discussed in Keay (2006).

type of plant, especially given that the plants are required for policy rather than commercial reasons and represent a higher-cost option than existing plants on the system.

Giving signals for investment in liberalized electricity markets has long been recognized as a major challenge, as explained in Part 2 of this study. One way of reducing risk for investors is by guaranteeing long-term prices. There are various ways of achieving this; one is that chosen by the government in its proposals for feed-in tariff contracts for differences. As discussed in Part 2, FiTs could be developed so that they become de facto long-term contracts, providing some certainty to underpin investment and reduce the cost of capital. They also allow for flexibility; not all contracts need have the same terms so the price can vary over time, as each successive round of FiTs is signed, and between technologies. The government can determine the rate and type of investment and use the information it gains at each stage to fine tune its approach for the next. It can use the minimum carbon price as a flexible supporting measure, without the burden of underwriting the credibility of the whole decarbonization strategy.

But this approach entails risks, essentially because it puts the government in the driving seat, leading it to determine the course of development of the electricity system. Some will consider these risks excessive – the government (or central agency) will decide the type of capacity to be built, when and on what terms, and may well be conservative and risk-averse in its decisions. They may further argue that it will take on (or at least pass on to electricity consumers) the risks of such investment, giving investors less incentive to manage risks and costs, and that government (or its agent) will be in a weak negotiating position. By setting up the EMR system, the government has effectively assumed responsibility for ensuring security of supply as well as emissions reduction; individual companies, by contrast, have no such obligations. The government or agent will therefore be the demandeur – the party which needs a particular result – but, lacking good information about the costs of providing that outcome, may well end up overpaying under the contracts (as has often happened in the past). Over time, investment remunerated under the new FiT arrangements, or through capacity mechanisms, is likely to come to dominate the market. Even if such investment might have been viable without the EMR measures, the existence of the measures and the

distortions they introduce into the market could even increase uncertainty to the extent that investors will prefer to take advantage of the mechanisms for the security they give.

As a result, not only may costs be excessive and innovation stifled, but price signals to, and the response from, consumers will be blunted; consumers themselves, via their suppliers, will be dealing with the government as contract aggregator, rather than directly with generators. The arrangements under which price signals will be passed on to suppliers are not yet clear but there is a risk, given the underlying structures, that the process of giving preference to a particular group of generators and shielding them from risk might obscure the cost signals which would otherwise pass between producer and consumer. The general risk is that this might inhibit the development of innovative approaches to managing the costs and uncertainties.

At worst, if the approach to FiT costs adopted in most countries[10] were employed, the costs would simply be 'smeared' over prices, in other words, they would be included as a fixed uplift element in prices, thus reducing signals related to predictability, flexibility, peak management, etc. The rump market, which will remain, and which will underlie the CfD element of the contract, could in principle give such signals. However, given that most participants, whether producers or consumers, will not in practice be fully exposed to its prices, it will be an artificial market. It is likely to be highly volatile, unpredictable, and open to gaming. Reform of this rump electricity market is, however, likely to prove difficult, given that it will form part of the contractual arrangements for most generators, who will be reluctant to lose any advantages they have gained by the interaction between FiTs and market prices. Yet – as discussed in Part 5 – reforms to produce more flexible and variable trading relationships are almost certain to be needed as part of the move to a low-carbon system.

One example of the potential problems caused by the EMR arrangements is in the proposed capacity market. The government says that it is in principle keen to encourage demand-response bidding (bids to reduce demand at peak times) but the arrangements do not appear well-suited to this task. Framing the auctions round a future delivery date is clearly designed with the construction of supply-side options in mind (these normally

[10] However, hitherto most countries with FiTs have operated relatively simple arrangements and have not relied on FiTs for the bulk of investment in the system. Parallels may therefore be difficult to draw.

come on stream in fairly large increments) rather than the development of demand-side response, which tends to be gradual and diverse, as large numbers of separate consumers are aggregated into a collective response capacity over time. The government's *Technical Update* to the White Paper (HMG 2011b) suggests that secondary markets (in other words, markets between the capacity auction and delivery year) might be one way out, but at this stage it is difficult to see how significant or liquid such markets are likely to be, and there appears to be nothing in the either White Paper or Update to encourage demand-response specifically (though the government hints that there may be some proposals to come in an electricity systems policy).

The scope for such markets could be considerable, as discussed in Part 5 – indeed they could well form an integral part of the operation of the future low-carbon system. But development in this direction could be inhibited by the existence of the EMR arrangements – directly, if they blunt the incentives of individual players in the market, increase transaction costs, and complicate future market reforms; and indirectly if by putting the government at the centre of the structure, they slow down the process of decision-making and reduce the incentives for innovation and risk-taking. Indeed, the very existence of the EMR could preclude other more flexible options – once nearly all generators are remunerated on a risk-free long-term basis via its mechanisms, unravelling the whole structure will be nearly impossible, precluding the possibility of developing an effective market and pricing system for the future low-carbon power sector.

Interestingly, the government appears to recognize the need for an exit strategy – in May 2012 it published its *Draft Energy Bill* (HMG 2012) for consultation. The explanatory material for the Bill sets a clear goal of stepping back from intervention, but without spelling out how it will be achieved. It lists four stages of EMR. By the fourth stage (late 2020s and beyond) it expects 'technologies are mature enough and the carbon price is high and sustainable enough to allow all generators to compete without intervention'. But it does not explain how the government will then escape from the complex web of regulation and long-term contract arrangements which will be in place. Nor does it say why the heavy administrative superstructure of the EMR is needed if the outcome is so clear – that is, if it is indeed the case that a carbon price of £70/tCO_2 (which is the target for 2030) will be sufficient to remunerate all forms of low-carbon

generation, including carbon capture and storage, nuclear, and offshore wind – why cannot the government simply commit to that price now and let the market respond by building low-carbon generation accordingly? If on the other hand, that outcome is uncertain (as must be the case) how will the government remove itself from the scene, when the whole system is underpinned only by its decisions and instruments?

In short, it is not clear whether the EMR arrangements are sufficiently well designed to meet either the shorter-term objectives – of stimulating the required amounts of low-carbon investment at reasonable cost – or the long-term objective of an efficiently operating low-carbon system.

An alternative market friendly approach: tradable carbon intensity targets

So, if we accept these arguments, the question arises: are there other options which might at the same time meet the government's objectives for the transition to a low-carbon system, prepare the way for the future operation of that system, and leave scope for the operation of market forces? Part 1 of this study explains why carbon pricing on its own, even if it may be the 'first best' option in theory, is unlikely to be effective or attractive to governments. This section looks at an alternative 'market-friendly' approach based on the use of **Tradable Carbon Intensity Targets** to promote low-carbon generation.

The basic idea is that there would be a cap, expressed in terms of carbon intensity (g/kWh), applying to all electricity generation within a given system. Individual caps would apply for each year (or other chosen period) and be set in advance over a long time period to give guidance for investment. The obligation would be tradable. There are broad precedents for such a scheme, in particular in the USA where the idea of carbon intensity limits has some traction; there have been proposals to apply such limits to electricity (the 'Clean Energy Standard') and for trading schemes in the transport sector.[11] The approach seems to have potential to be applied to the UK and other EU countries in relation to electricity decarbonization.

[11] See, for instance, EIA (2011), which looks at the implications of an intensity based approach for electricity. See also CSEM (2009).

As noted, the UK already has an informal cap of this sort – the government's aim is to get carbon intensity below 100g/kWh by 2030, from around 480g today. This could be translated into a formal arrangement by setting a cap for each year up to 2030 on a declining trend. For the purposes of illustration this could be a steady reduction of about 20g/kWh per year (in other words 460g in 2012; 440 in 2013 etc.) though in practice the trajectory would need to take account of the potential pace of investment. Further targets for the 2030s could then be set in, say, 2020, by which time more information should be available about the viability of CCS, new nuclear etc., but the government could indicate at an earlier stage its expectation that the cap would fall to no higher than, say, 50g/kWh.

The idea would be that the obligation would give a clear signal to generators about the nature of the future capacity needed and that, because of its tradability, it would give flexibility in operation and strong incentives for cost minimization.

How it might work

The requirement would be imposed via an obligation on all generators, whether new or incumbent, to meet the carbon intensity cap (though there might be an exception for those under, say, 50MW). They could comply with this obligation by one of the following methods:

- Keeping the carbon intensity of their own generation within the cap.
- Buying carbon intensity reduction certificates (CIRCs) from other generators to bring their intensity down to within the cap.
- Paying a penalty (or buying reserve CIRCs from the government) to make up any shortfall.

The obligation would apply across a generator's entire fleet (which could, of course, be an individual plant only) and would be calculated by taking total carbon emissions during the year (or other chosen period) divided by total electricity generation from that fleet or plant. Both figures are in principle easily obtainable and unambiguous.

The example below shows how the scheme might operate in a situation where the overall target is met. Say the target for 2020 is 300g/kWh and there are three generators: A has a mainly coal fleet and an intensity of 600g/kWh; B has a mainly gas fleet and an intensity of 400g/kWh; C has a fleet composed entirely of zero carbon generation with no emissions. In total they produce 1 TWh, and 300,000 tonnes of CO_2, as below:

	Output	**Carbon Intensity**	**Carbon Emissions**
Generator A	**300 GWh**	**600g/kWh**	**180,000 tonnes**
Generator B	**300 GWh**	**400g/kWh**	**120,000 tonnes**
Generator C	**400 GWh**	**0g/kWh**	**0 tonnes**
Total	**1 TWh**	**300g/kWh**	**300,000 tonnes**

To comply with the target, both generator A and generator B would buy credits from generator C until they were within the limit.

Various possible mechanisms for the trading are possible and some of these are discussed below, but most do not fundamentally affect the basic structure of the scheme.

Some options:

- **Virtual or actual**? Generator C could either sell a given quantity of electricity (in the example, 100 GWh to B and 300 GWh to A) or sell virtual electricity in the form of a CIRC. It is suggested that both options should be available, or any mix between them, to provide maximum flexibility and avoid market dominance by any particular generator.
- **Sales or swaps**? When it comes to virtual sales, the options would include sales (C would sell 100GWh to B and 300GWh to A and be left with nothing) or swaps (C would swap, say, 150GWh with A and 75GWh with B – each generator would then be left with the same amount of output but all would be at a system average intensity and so compliant). These options would need further examination but for the purposes of this study, the latter is preferred: by keeping virtual and actual sales separate, monitoring and compliance should be simplified.

- **Units for trading**? In the examples the units are virtual electricity output at a given carbon intensity. In principle it would be possible to trade carbon instead (as has been proposed for one variant of the broadly comparable US Clean Energy Standard). Indeed, in terms of trading within the year, the proposed scheme is effectively an emissions trading scheme. The key difference between it and a conventional trading scheme is that it gives certain, predictable, and long-term signals for investment, which is the key to decarbonization. In principle, there could be two classes of emissions trading – CIRC certificates and ETS certificates. However, that option could give rise to confusion, and there is a strong case for keeping the two schemes clearly distinct. In addition, trading of virtual electricity output seems closer to the main aim of the scheme and easier to understand and implement.
- **Negawatts**? It is in principle quite possible, and in practice highly desirable, to include demand-side measures ('negawatts'). In the above example, for instance, 100GWh of generator C's zero carbon production could be in the form of negawatts. Clearly a proper system of verification would be needed, and relatively high set-up and transaction costs would be involved. But this sort of verification is necessary (though not always provided) for any serious energy efficiency programme, and once the initial scheme is set up the transaction costs need not be excessive. It is true that, if energy efficiency is as cost-effective as its proponents claim, there should be ample incentives to develop monitorable schemes – under the arrangements above they would effectively benefit from the sort of income currently going to renewable sources.
- **Supplier or generator obligation**? The obligation could in principle be placed on either suppliers or generators, but the option illustrated here is a generator obligation. In contrast, the proposed US Clean Energy Standard would be a retail supplier obligation (like, say, the renewables obligation in the UK). There are arguments for both approaches, and the choice would depend on the nature of the system concerned and the specific objectives and orientation of government policy. It is arguable that a generator obligation would be simpler and easier to implement (see under 'Business Friendly' benefits below), create greater certainty, and avoid the strong pressure to engage in long-term contracts which a supplier obligation would create (and which could in turn have the effect of limiting competition by creating barriers to entry). Generators, who

have to invest in long-term assets, are arguably more likely to take a long-term approach and have a greater long-term commitment to a particular market than suppliers, whose investment is less and whose greatest assets (their customers) are always liable to move to another supplier. On the other hand, it could be argued that a supplier obligation is most likely to sharpen competition, by creating strong incentives for suppliers to negotiate effectively. It could increase the customer responsiveness of the system because of the suppliers' direct relationships with their customers, and could lead to greater innovation (for instance, suppliers may be more likely than generators to consider demand-side options since they have less financial and psychological investment in generating plant as such). There is no clear answer and the choice would depend on circumstances.

- **Small generators**? The suggestion is that small generators could participate on a voluntary basis. This would give an incentive for distributed low-carbon generation (such as roof top solar) while enabling other forms of small-scale distributed generation to avoid bureaucratic complications.
- **Autogenerators, CHP etc.**? Similarly, these generators could in principle participate in the scheme, although initially it might be better for such participation to remain on a voluntary basis. Special arrangements would in any event be needed – for example to determine the carbon intensity of generation from CHP schemes.
- **Island generators?** (actual or metaphorical) In principle these could be included in the scheme; their options for physical trading would be limited but they could still engage in virtual trading. (Actual islands might however require special or transitional arrangements to reflect their particular circumstances).

Another major issue, which is probably more than a design detail, is the nature of enforcement – what happens if targets are missed? (Monitoring should not be a problem, as indicated above.) There seem to be two main options, though they could overlap and merge:

- **Punitive** The principle here would be to set a high penalty for any failure to meet the target, so as to provide strong incentives for compliance. The advantage is that this is more likely to ensure that the targets are met; the disadvantage is that it may add to risk and push up costs in a distorting manner.

- **Cap on cost** The principle would be to set something like a reserve price; the government would then issue as many extra CIRCs as needed at that price. The government would set the price at a level which was at the upper end of the range of the expected costs of low-carbon generation; this would provide an incentive to reduce costs but ensure that the ultimate burden on consumers was capped. On the other hand it would not ensure that the target was met.

Although the two approaches are quite different in principle, they could be combined in practice – for example a contingency reserve of CIRCs could be established of, say, 5–10 per cent of total generation; anything in excess of that would bring the penalty system into operation. It could be applied at the level of the individual generator, in other words, any emissions above the threshold for that generator would attract the penalty. Alternatively, it could take the form of a double threshold, with the penalty scheme only coming into operation when the system as a whole was above the overall threshold; penalties would then apply to each individual generator's excess above its own threshold.

Other wider issues:

- **Interaction with other schemes** The interaction with carbon trading is discussed below. But one of the advantages of the proposal is that it removes the need for most, if not all, of the other complicated components of the UK government's current market reforms. **Feed-in tariffs** would not be needed to drive low-carbon investment as that would be driven by the intensity target, so central purchasing, government-determined contracts, central price-setting, and all the other potential distortions would be removed. It might still be necessary, for political reasons, to provide special support for particular technologies but (see below) it is one of the advantages of the scheme that that support would need to be more transparent and clearly motivated. **Capacity payments** might also be unnecessary, though they would be compatible with the scheme if it were felt necessary to retain them. There has been a long debate over the need for capacity payments, with no clear answer. The volatility of prices in a low-carbon system has, for many, tipped the balance in favour of a capacity payment scheme, to reduce uncertainty. However, it is arguable that an intensity trading scheme would provide strong incentives for new investment while at the same

time discouraging unnecessary closures – if prices are as volatile as expected, this should give a strong incentive to maintain old plants in service so that they can take advantage of short periods of high prices, while not having a material impact on a fleet's carbon intensity. **Emissions performance standards** would be unnecessary, as the intensity target would supersede them. **Minimum carbon prices** should also be unnecessary, at least for environmental reasons, though the Treasury might want to retain them for revenue-raising purposes.

- **Carbon trading** In the concept as it stands at present, the scheme would run in parallel with the ETS or other trading scheme. It should be possible to make the two compatible by setting ETS allocations which take account of the carbon intensity targets, and are based on the assumption that they will be achieved. The carbon price would then have two main functions in relation to electricity – it would affect day-to-day operation of the fleet in place (for example, the choice between gas and coal) and it would provide a linkage with other sectors so that the operations of the electricity sector were not completely isolated from the wider economy. (Electricity does of course have a special position under the proposed intensity arrangements, but that is already the case in most countries; the reasons are discussed in Part 1. Furthermore, the new arrangements would be significantly less distorting than the present position – see the section 'Main benefits of scheme' below.) The intensity target would not, on its own, ensure that any particular future emissions target was met, but as yet there are no specific emissions targets for the post 2020 period anyway, and if the emissions targets were set as recommended, the two schemes should be mutually supportive rather than contradictory.
- **Europe** In principle, the boundaries for trading could be set as widely as desired and the scheme could operate, for instance, at a European level. In practice, in such a situation, transitional arrangements would be needed for a long period given the present differences in carbon intensity between, say, Greece and Estonia on the one hand (both over 700g/kWh) and Sweden and France on the other (both less than 100g). But the EU is good at developing transitional arrangements designed to promote burden-sharing (it has already done so, for instance, with renewables targets). It should be possible to develop a scheme which required all countries to move, over a period of time, towards a common

intensity target, while meanwhile recognizing different targets in different countries as a basis for trading.

Main benefits of scheme

The scheme should provide the following benefits:

- **Policy effectiveness and efficiency** As noted above, a carbon price could not be guaranteed to produce the low-carbon generating system the government is aiming at. Even the EMR remains highly uncertain on this score – until the proposed FiTs are actually negotiated, it is not clear how much low-carbon plant the system will deliver. Furthermore, as noted above, the government will be in a weak negotiating position, with no sanctions available, no requirement on generators to invest, and no real information about the appropriate price for the low-carbon generation it is purchasing on behalf of consumers. Faced with the unpalatable alternatives of offering excessively high prices or compromising its security and environmental objectives, the government may well find it difficult to reach a satisfactory outcome – the result could be a lengthy stand-off in the negotiations. The timescale is already protracted – contracts are unlikely to be signed before 2014, by which stage there will be little time left to mobilize the necessary investment for 2020 – so it is unlikely that the EMR objectives will be met. The proposed carbon intensity targets cannot guarantee the necessary low-carbon investment either, but they do have the advantage of defining a very clear requirement for companies that intend to operate.
- **Credibility, certainty, and predictability for producers** Generators would know a long time in advance what their targets would be and could plan their investment programmes around the targets. There is at present something of a cycle of uncertainty. The failure of the ETS to drive investment leads to a need, across Europe, for special support for renewables, energy efficiency etc.; that support in turn undermines the ETS price, so making it an even less credible instrument. Yet the specific schemes of support for renewables etc. have been subject to fundamental changes in many countries, as have attitudes to nuclear, making the nature of future schemes unpredictable. The carbon intensity target, by contrast, should provide credible, predictable, and reliable long-term signals for investment.

- **Business friendly** This form of target is familiar to generators and easy to implement. Indeed, many generators have used such a target – for example, E.On had the aim of reducing carbon intensity by 10 per cent between 2005 and 2012;[12] Vattenfall wants to reduce by 50 per cent by 2030;[13] RWE set a target of 50 per cent reduction between 1990 and 2015.[14] Companies use such targets to guide their investment programmes. A statutory target would give an even clearer frame of reference for investment planning.
- **Transparency for investors** Investors would be able to assess generators on the basis of the carbon intensity of their existing fleet, and their plans for reducing carbon intensity. This would create investment pressure for reductions by the integrated utilities and increase the attractiveness of low-carbon generation projects.
- **Efficiency and cost effectiveness** The target would provide strong incentives for cost reduction, which the EMR proposals and other European renewables support mechanisms arguably fail to do. It would encourage entrepreneurs to find both the lowest cost forms of low-carbon investment and the most efficient trajectory for reduction.
- **Technology neutral** A particular advantage of the proposals is that they are technology neutral, allowing markets to discover the best mix of technologies. Of course, this could be a problem for some existing renewables and CCS schemes and they might require special or transitional arrangements. But this is in principle also desirable. Support for renewables in particular is at present based on a mish-mash of motives – emissions reduction, industrial policy, technology forcing, energy security etc. – and the government is effectively picking winners against this uncertain background. If the support schemes have to be made more transparent, the government will have to clarify its objectives in giving technology-specific support not based on emissions-reduction benefits. In any event, the UK government has made clear its preference to move towards a more technology neutral scheme after 2020.
- **Market neutral** This is another significant benefit – the arrangements could in principle be combined with almost any market structure, such as power pools,

[12] E.On *2006 Corporate Social Responsibility Report.*
[13] Vattenfall *2011 Corporate Social Responsibility Report.*
[14] RWE Npower 2011 *Corporate Responsibility Report*

GB-type mechanisms etc. This has two major advantages: first, by leaving all power to be sold through these mechanisms, it avoids undermining markets and pricing signals and creating distortions via the sort of parallel markets currently proposed; second, it leaves consideration of long-term market structures for independent analysis and development over time. At present, the UK market reform proposals are likely to pre-empt consideration of future market structures, as discussed above, and there is no clear exit strategy. With the carbon intensity proposal, on the other hand, markets can be left to operate in the interim and redesigned without constraint, for the future situation when the objective (getting below, say, 50g/kWh) has been reached – by then the intensity target will be no more than a general background framework. Part 5 discusses these issues further.

- **Flexible and market friendly** The arrangements can be designed to accommodate all sorts of generation, and integrate them into the new system over time. They leave it up to individual generators to make their own decisions but create attractive new markets in the form of CIRCs which would be accessible even to relatively small-scale low-carbon generators. They will not require time-consuming, complex, precedent-setting negotiations on the lines of the EMR, and so could have an impact relatively quickly. They also leave the shape of the future electricity system open to markets to determine – that system is likely to look very different from at present – and it is important not to prejudice the path of development as the EMR proposals do.
- **Good for the demand side** As already noted, it should be relatively easy to accommodate the demand side in the new arrangements. This approach thus differs again from the EMR proposals, which are based on contracts for the future construction of large increments to supply. Demand-side measures operate more gradually and less predictably. However, under the intensity scheme, provided they were verified, demand-side measure would instantly have a high market value and tradability; long-term advance commitments and investments would not be needed, but nor would they be discouraged. The incentives for developing demand-side measures, even given the uncertainties, would be high.

In short, the intensity proposal seems to have many potential benefits. Against that must be set the key questions of credibility and uncertainty – the proposal would involve a

major change in approach for most governments, and would not directly guarantee investor revenues. Would it provide a strong enough basis for investment and be credible over the long term? Given the novelty of the approach there can be no definitive answer to these questions at this stage. However, it is arguable that a commitment to an intensity target would be more credible than a commitment to a future carbon price or emissions cap. It is simpler in form, more closely related to the emissions objective, more likely to deliver a least-cost solution, and does not depend on (or constrain) assumptions about the growth in GDP or electricity demand, so there is less reason to expect the government to change the target.

Part 4: Improved Wholesale Markets

Introduction

The central thesis developed in this part of the study is that it is possible to improve existing wholesale electricity and CO_2 markets, and to establish additional markets, to meet three main policy objectives: resource adequacy, decarbonization, and economic efficiency. In other words, there is an alternative to state planning and central purchasing which can achieve these three policy objectives.

This approach shares some characteristics with the EMR approach, including the creation of capacity markets. It also assigns an important but different role to government, leaving markets to play a greater role than in the EMR. It relies on the original hypothesis behind liberalization, namely that competition and decentralization of investment decisions provide good incentive properties, provided markets are well designed; as such, it fits comfortably with the proposal of a carbon-intensity target. Given that even a centrally driven approach, such as that outlined in Part 2, would be likely to retain core elements of existing wholesale markets and system control by the grid, at least in the short- to medium-term, some parts of this approach will be relevant whatever broad pattern of reform is eventually adopted.

This part of the study considers two types of reform: to wholesale electricity markets and to CO_2 markets. For each, we introduce the main challenges and then identify specific reform proposals.

EU wholesale electricity market challenges

The literature surrounding the EMR debate has identified a number of problems that face most EU electricity markets undergoing a process of decarbonization. But the UK is in a unique position for a number of reasons. As explained earlier in this study, the UK has a particularly ambitious decarbonization agenda, which requires very substantial investment in the very short term. As an island with limited interconnection capacity, it is able to design its reforms in relative isolation, even though many of the

EMR decisions do affect EU markets and are affected by them. Above all, the UK Government is in a hurry to encourage investment in both conventional and near zero carbon technologies, and this partly explains the high level of government intervention in the ERM proposals. Without such intervention, the government is worried that the necessary investment will not occur in time to meet policy objectives, some of which are now legally binding. While the solutions in the UK may not be a model for the rest of Europe and the context is different in each country, many of the problems are common across the EU.

There are at least three common problems:

(a) the increasing difficulty of relying exclusively on energy-only markets to drive investment in conventional plants;

(b) the impact of intermittent renewables on energy prices and cost recovery of conventional plants – hence the concern over inadequate investment; and

(c) market power within national or regional markets.

In addition, there is

(d) the need to improve the incentives in short-term energy markets, for instance with better price signals for balancing.

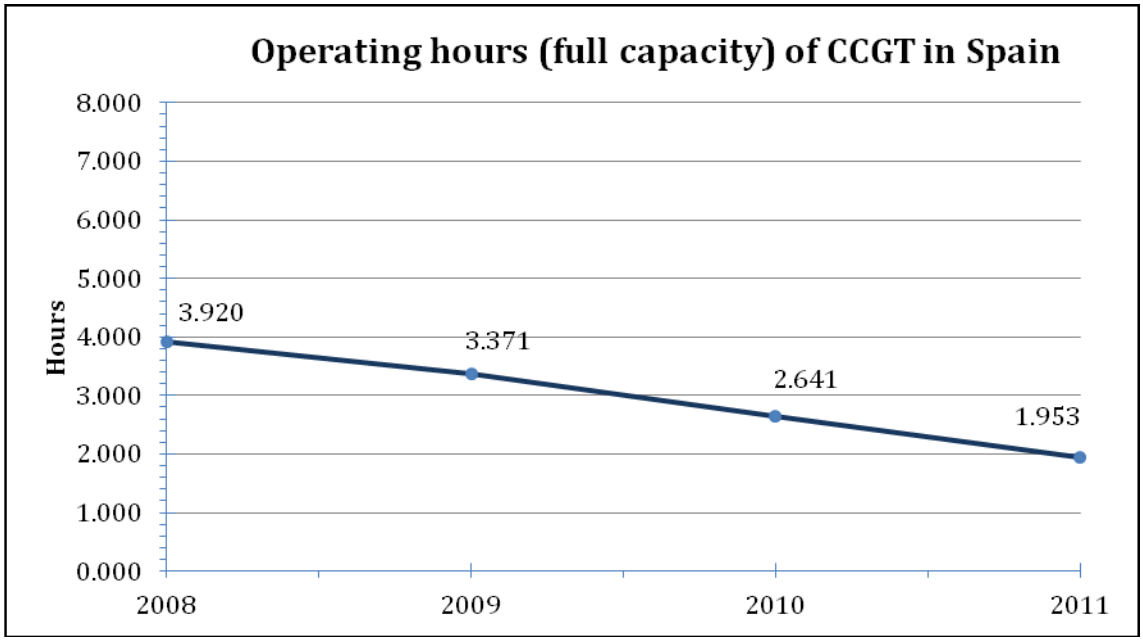
Problems (a) and (b) distort generation investment decisions related to conventional generation, in particular to coal- and gas-fired plant. Energy-only markets, which have no additional remuneration to recover the fixed costs of capacity, are conceptually sound. However, in practice, investors that rely solely on revenue streams from the sale of energy sometimes face a 'missing money' problem, or at least worry that they might face that problem. In other words, in certain circumstances, spot wholesale electricity market prices for energy and operating reserves:

> … will simply not be high enough to cover both the operating costs and the capital investment costs (including an appropriate risk adjusted cost of capital) required to attract new investment in long-lived generating capacity to support a least cost generation supply portfolio consistent with mandatory reliability criteria. Joskow (2006)

This problem does not always exist. Indeed, most EU countries still have energy-only markets that function effectively enough. However, the growth of intermittent

renewable generation with zero marginal costs makes investors in CCGT and coal plant increasingly nervous about relying entirely on uncertain revenue streams from the energy market – especially when governments signal their intention to intervene to stop energy prices from rising. For investors in conventional generation, the missing money risks now include not only the possibility of price caps, but also increased price volatility and reduced generating hours. By way of illustration, Figure 1 illustrates the decline in operating hours for CCGT in Spain over the past four years; and this is after an earlier decline from about 5,000 hours in 2005.

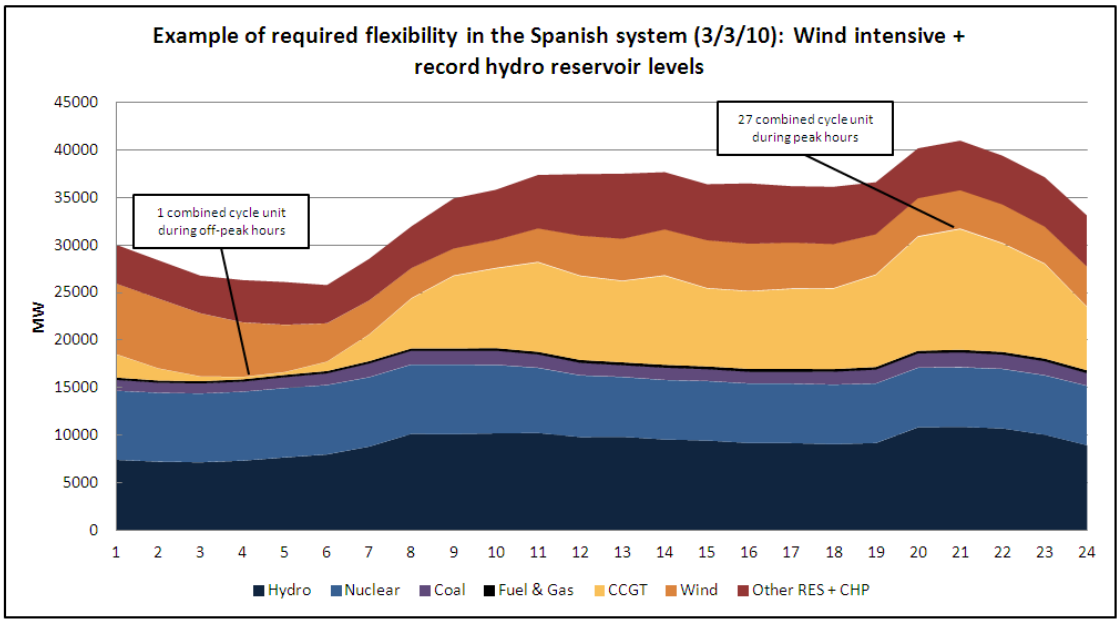
Figure 1: Decline in operating hours for CCGT in Spain 2008–11



Source: CNE (2012, 2).

At the same time, the growth of intermittent renewable power increases the importance of having flexible backup reserves, typically from CCGT plant, to respond to changing output from wind and solar. Figure 2 illustrates the importance of this flexibility on one day of particularly high wind and hydro resources in Spain: in the off-peak period, only 1 CCGT is needed, but at peak, 27 CCGTs are operating. The question is how to ensure sufficient investment to provide this sort of flexible backup if the energy-only market is unable to guarantee sufficient revenue to justify the investment.

Figure 2: The need for flexibility to cope with intermittent renewables



Source: REE

Market power (problem c) can distort investment and operating decisions in different ways. High levels of horizontal concentration in generation or retail can raise energy prices to final customers above competitive levels. Meanwhile, vertical integration among a small number of large companies can reduce wholesale energy market liquidity and thereby raise barriers to entry for specialized generators and specialized retail companies. Although market power has helped to finance and justify investment in the past, this model is coming under pressure due to the rising financing requirements to meet climate change objectives, as well as pressure from regulators to make markets more competitive. The vertically integrated companies are no longer able to finance the massive investments that are required to meet government targets, and governments are looking for ways to facilitate investment by pension funds and specialized new entrants on the supply side and the demand side of the market.

Proposal 1: Improved short-term energy markets

Most EU countries have competitive wholesale energy markets that work reasonably well in terms of short-term operational efficiency and security. However, the design of wholesale markets could be improved – especially to encourage more effective competition, and to provide better signals for efficient investment, including investment

by new entrants. There are four specific ideas that are under discussion in one or more EU country: greater liquidity in wholesale electricity markets; better balancing markets; nodal prices; and integration of EU electricity markets. Without going into detail, here are some of the proposals being considered on each.

- **Liquidity** In most countries wholesale electricity markets are relatively illiquid, compared with other commodity markets like oil. This tends to discourage entry, both for independent generators and for specialized retail companies. The former find it difficult to lock in revenue streams, especially for longer periods; the latter to find suitable financial contracts to hedge the price that they offer to their customers. In the UK, Ofgem (Ofgem 2012a) have considered two specific proposals to address these problems: to oblige the main vertically integrated companies to act as 'market makers', guaranteeing a supply of particular financial products; and to require mandatory auctions of a proportion of their generation in the form of forward financial contracts of different lengths. Ofgem have decided to pursue the idea of mandatory auctions. Other regulators might wish to consider these and other measures to improve liquidity.
- **Better balancing markets** Balancing prices (or 'cash out' prices) provide incentives to balance supply and demand in the short term, but also provide longer-term signals that can influence generation maintenance, investment decisions, and the incentives to provide demand response. Ofgem has recently initiated a Significant Code Review because they are concerned that the ash-out arrangements in the GB market are inadequate. In particular, they have indicated concerns about the longer-term impact of the current regime, which may raise costs and reduce system security (Ofgem 2012b). At a European level, further integration of balancing markets would enable significant savings, since each country would otherwise be maintaining its own reserves.
- **Nodal pricing** Currently, wholesale prices in many EU countries do not reflect transmission considerations. This distorts investment decisions, in particular by ignoring the additional transmission costs required to integrate new sources of generation. Nodal pricing would give better signals for the location of new plants,[15] including renewable generation.

[15] Newbery (2011).

- **Integration of EU markets** In spite of the commitments and legislation to create single European markets for gas and for electricity, the EU is still made up of regional electricity markets that in some cases are poorly interconnected due to transmission constraints; this can make it more difficult to develop and integrate large volumes of renewable generation. To take but one example, the paucity of electricity interconnector capacity between Spain and France means that the Iberian peninsula is basically an island market, where investment and prices are determined almost entirely by domestic policy decisions (such as, how much renewable energy to build, or whether to run domestic coal). In the last two years, the EU has progressed quite substantially in the process of integrating European markets – through the creation of 'target models' for electricity and gas markets, along with procedures for integrating (through market coupling) the regional markets. The process is supposed to lead to a fully integrated market for electricity around 2015. However, the process of full integration will require substantial investment in interconnection, and the political will to support these investments.[16]

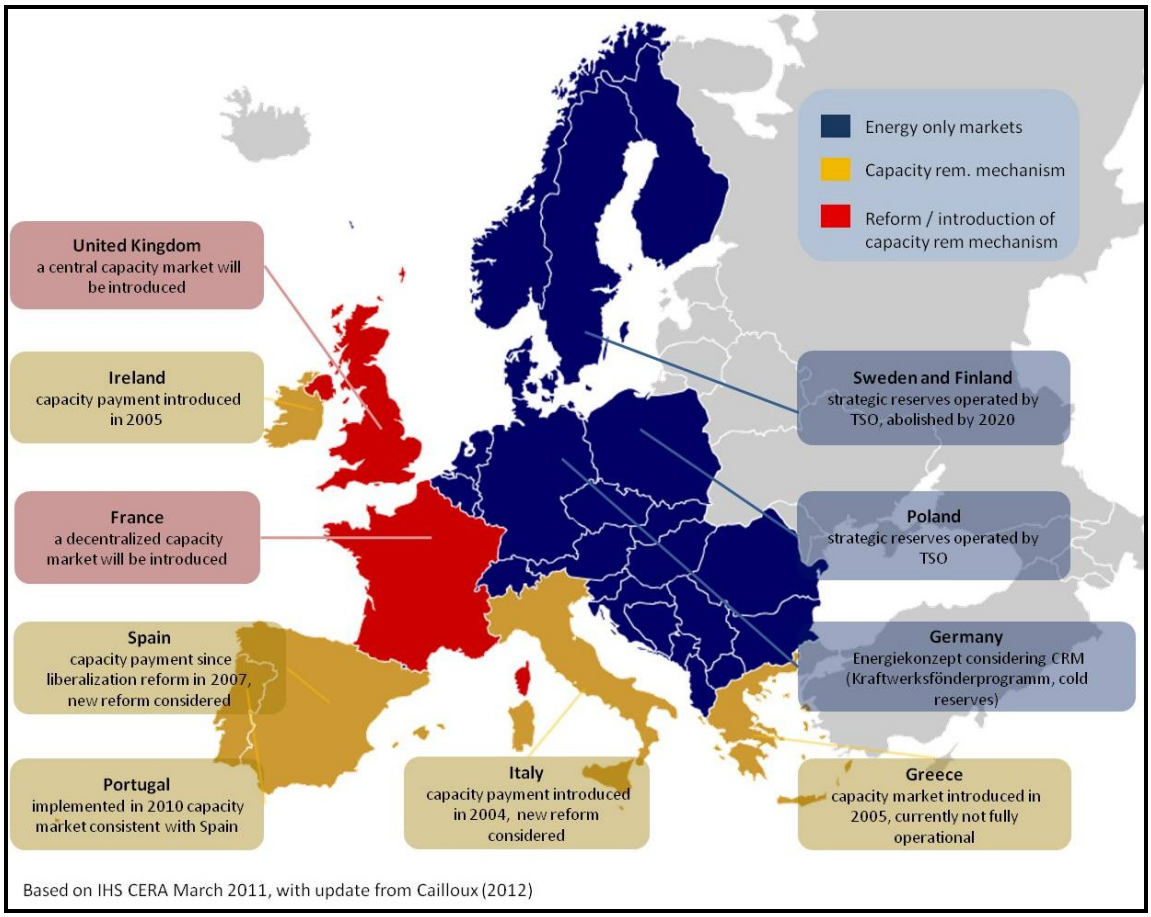
In spite of the difficulties, there is a broad consensus that wholesale short term electricity markets are valuable and should be reformed to operate as efficiently as possible, rather than be replaced to deal with the challenges of decarbonization. Countries such as Spain, Germany, and Denmark are already addressing some of the problems related to high levels of intermittent renewables, for instance zero prices and declining hours of operation for conventional plants. However, no country has yet completely come to grips with the full implications of decarbonization for wholesale market design and operation. In Part 6 of this study, we have identified some of the key issues that will need to be addressed.

[16] See Jacottet (2012) for an overview of some of the issues.

Proposal 2: Capacity payments, contracts, and markets

Most EU countries have energy-only markets, as Figure 3 illustrates.

Figure 3: Generation Capacity Remuneration Mechanisms in Europe



There is a growing consensus among academics and industry analysts and participants that the energy-only structure is not well adapted to remunerating capacity in systems with large amounts of intermittent and capital-intensive generation.[17] This leads to the discussion of different models to contribute to the remuneration of the fixed costs of capacity.

The models under discussion can be separated into two broad categories: payment-based and quantity-based. The payment-based approach involves providing capacity payments – set by an administrative decision or mechanism – to supplement the payment in the energy market. The quantity-based approach involves determining the

[17] See in particular Cramton and Ockenfels (2012) and Hesmondhalgh et al. (2010).

quantity of resource required and then allowing prices for this resource (reliable capacity) to be set by competitive mechanisms. There are many variations on each of these, but the decision boils down to whether the regulator fixes a price or a quantity.

Figure 4 summarizes the arguments for and against 'capacity payment' models. This approach has been adopted in a number of countries, including Spain and much of Latin America. Fixing a capacity payment through an administrative procedure allows the regulator to adjust the price of capacity to deliver the desired capacity margin. It also has the advantage of limiting price spikes and may lower risk/cost by providing greater revenue certainty to investors. Furthermore, it allows for differentiation in prices for existing and new capacity, and could help to reduce resource adequacy risk that is associated with the growth of intermittent renewables.

The greatest problems with this approach are the significant discretion given to the regulator that can create regulatory uncertainty for investors, and the fact that administrative prices will be either too high or too low – leading either to excess investment and cost, or to inadequate investment. It may undermine demand-side response because these systems are normally designed to promote investment in generation. It may also introduce price distortions if capacity prices are set at the wrong level, or if they are recovered from customers through energy payments rather than for demand at peak.

Figure 4: Capacity Payment Models

What payments?	Energy Markets Payments and Administratively Determined Capacity Payments	
	Advantages	**Disadvantages**
Resource Adequacy	· Energy price spikes can be mitigated · Greater revenue certainty · Provides regulator with flexible tool	· No guarantee that the desired level of capacity is reached · Can distort market prices · Potential to undermine demand-side response · Increases regulatory risk
Low Carbon Objectives	· Less risk than for energy only of problems over resource adequacy	· Heavy burden on regulators · Increased regulatory risk, particularly if political involvement

By contrast, quantity-based models impose an obligation, typically on retail or distribution/retail companies or on the system operator, to purchase a sufficient quantity of capacity to meet the demand of their customers, including a target reserve margin. Government may itself take on the obligation, or transfer it to a central purchasing agency (as discussed in Part 2 of this study).

Figure 5 summarizes the advantages and disadvantages of quantity-based models. Their main advantage is that they can ensure resource adequacy, including reserve capacity to back up renewable power. Furthermore, if administered through an open competitive procedure, they can encourage innovation – because they enable consideration of all of the alternative supply sources, including demand response. They also provide revenue security for investors and, by lowering risk and the cost of capital, can help to lower costs.

The disadvantages of the quantity-based models include the difficulty of having different prices for existing and new plant (there will be a single market price for capacity) and the transactions costs for small retail companies. They may also be complex to manage, especially if they include organized capacity markets.

Figure 5: Quantity based models

What payments?	Energy Market Prices and Capacity Market Prices	
	Advantages	Disadvantages
Resource Adequacy	· Should achieve the desired level of reliability · Can provide revenue security · Encourages innovation · No distinction between new and existing capacity	· If based only on bilateral contracts, can create market power and raise transaction costs for small players · Complex if organized capacity market is included
Low Carbon Objectives	· Helps create sufficient operating reserve capacity	· Low carbon quantity requirements can be complex · Feed-in-tariffs can overcompensate (or be insufficient)

The quantity-based model has an increasing number of adherents: it is the basis for most of the capacity remuneration mechanisms in the USA and is being considered in a number of EU countries, including Italy, Germany, and the UK.

One specific variant of the quantity-based approach that seems to be gaining support in the EU is the use of 'reliability' option contracts,[18] usually with the following characteristics:

- **A quantity-based obligation is placed on the buyer of capacity** – which in the EU could be a retail company, a large customer, the system operator, or a Single Buyer established by the government. This obligation would typically require these buyers to have long-term contracts covering all their demand, possibly including a reserve margin; failure to have such a contract would be penalized.
- **Sellers of capacity are required to provide evidence that they can meet their commitments to provide 'reliable' power**. This may be through evidence of physical plant, or through secondary contracts with other companies. In some cases, the requirement is not imposed, but the penalty for failure to deliver is punitive.
- **A long-term option contract enables the seller to earn a stream of income (the option fee)**, subject to the obligation to supply electricity at the strike price when the option is called, for example when market prices exceed the strike price. For instance, the buyer may have a one-way option that allows the buyer to pay the spot price for electricity until it reached the strike price, and pay the strike price when the spot price is above the strike price.
- **An auction or other competitive process** is used to select the plants that win the long-term contracts, and to determine the market-clearing price of the option.

There are many variations and we can mention a few of the key choices.

- **Centralized or decentralized** Whether the auction and contracting should be carried out centrally, or in a decentralized way; both models exist. For instance, in Chile, each distribution company is responsible for deciding how to meet its obligations, whereas in Brazil, the process is centralized.
- **Who can offer services?** Whether the auction is open to all forms of supply (including renewable energy, conventional generation, and demand response) or only to conventional generation, or even to specific types of conventional generation (like CCGT). PJM auctions in the USA allow all sources of generation and demand

[18] See Cramton and Ockenfels (2012) and EWI (2012). This approach has been adopted in Colombia and in the New England Power Pool. In Britain, the DECC is considering a version of this model, as is the Italian regulator.

response to compete. In Brazil, renewable energy and conventional energy compete in certain auctions (but not all) and some wind power has been selected ahead of CCGTs.

- **Contract length** A third important choice is over the length of contracts and the timing of the contract's entry into force. Since the aim is normally to facilitate investment, contracts are usually multi-year. In Latin America they can be 15–20 years. Typically, these contracts will enter into force at least one year from the auction and, more often, 3–5 years later in order to enable investors to build the relevant plant.
- **Secondary market** Some models include organized secondary 'capacity' markets so that buyers and sellers can trade their contracts. This provides a transparent value to reliability contracts and enables companies to buy or sell their contracts and thereby deal with changes in market shares resulting from customer switching, market entry and exit, and changes in demand and supply.

Proposal 3: Low-carbon generation

Even with the changes suggested above, the incentives to build low-carbon generation would need strengthening, since the primary objective of a capacity market is to ensure resource adequacy, not decarbonization.

There are three standard approaches to encourage investment in low-carbon sources: feed-in tariffs (FiTs) set by government or regulators, quantity obligations imposed on buyers or generators, and tax credits. Figure 6 summarizes some of the pros and cons of the main methods.

Figure 6: pros and cons of different methods to promote low-carbon investment

Advantages	Disadvantages
Feed-in Tariffs and Tax Credits	
1. Flexibility in the pace of growth of renewable installed capacity 2. Certainty about cash flow	1. Little control over capacity 2. Can be very expensive 3. No incentive to run when needed 4. Not technology neutral
Quantity-based Approaches	
1. No expensive overshooting 2. Encourage innovation (if no or limited technology carve outs)	1. Only work if no barriers to building plants 2. Revenue uncertainty can complicate financing 3. Often higher transaction costs

Many countries (such as Germany and Spain) have successfully built up the share of renewable energy through FiTs and tax credits. They have the advantage of flexibility and provide some certainty over revenue streams – thereby lowering the cost of debt financing. However, FiTs are increasingly being questioned: by governments because of the difficulty of setting prices administratively and the risk of overpayment when prices are set too high; and by investors because of the lack of legal guarantees in the face of retroactive changes to the FiTs.

Quantity obligation-based systems have been adopted in other countries, including the UK (the Renewable Obligation Certificates) and the USA (Renewable Portfolio Standards). In these systems, load-serving entities, like retail supply companies, are obliged to purchase a certain share of their energy from renewable sources. The main attractions are that these systems do not encourage expensive overshooting and they can encourage innovation, providing there are very limited technology 'carve outs' that favour specific technologies. Some countries combine quantity-based obligations with FiTs. For instance, China combines renewable obligations for the main coal-based generators with auctions to determine FiTs. The result is that almost all of the wind parks in China are owned by the large coal-based generators.

The specific proposal here is to build on the quantity-based approach outlined above to meet reliability (in other words, resource adequacy) requirements. Whichever organization has the obligation to meet quantified reliability standards would be required also to obtain a rising percentage of its contracted power from near zero-carbon

sources. The potential near zero-carbon alternatives would include renewable power, nuclear power, demand reduction, and (possibly) CCS-based coal and gas.

The goal is to select the least cost combination of supplies, not to promote specific technologies, so banding would not be part of the original proposal. This does not rule out subsidies or special support, but does require that this happen outside the electricity and carbon markets (for example through taxes).

Proposal 4: Organized reserve service markets

With the growth of intermittent renewable power, the economic importance of backup reserve has grown. In Figure 7, we see three different dimensions to resource adequacy: (a) short term reserves of different durations to provide stability to the system; (b) long term capacity to meet peak demand for about 100 hours per year; and (c) backup reserves to run about 1000–3000 hours a year to cope with intermittency of renewables. For the latter, the technology must have high efficiency and significant flexibility; CCGT normally provides this backup service, other technologies and demand-response can also play a part. Most reserve services are remunerated on the basis of a regulated reserve price, or through bilateral contracts with the system operator.

Figure 7: Generation adequacy and the need for a reserve to back up renewables

Generation Adequacy Simplified: Large shares of variable RES add a "3rd dimension"			
Need	Reserves (R1-R2-R3) = Short Term (continuous) adequacy	Long Term Capacity = Mainly peak capacity adequacy	RES Back-up Capacity Stand-by/flex capacity adequacy
Load Factor	· Primary Reserve = 0 · Secondary/Tertiary ≠ small	· Around "100" hours/year	· Around 1000 hours/year (but less than 3000h)
Plant Usage	· Specific technical features · Capacity procurement, energy = balancing	· Low efficiency (OCGT/Oil) · Only start/stop	· High efficiency (low CO_2) · Flexibility/regulation

Source: Cailliau (2012).

The proposal here is to create organized ancillary service markets in which all potential suppliers of backup reserve are able to compete for contracts. As with the reliability contracts described earlier, these are the key features of the model.

- **Obligation** An obligation on the system operator to contract for reserve services and other ancillary services, to provide a specified level of reliability to the system, under conditions that will allow for supply and demand-side alternatives.
- **Demonstrated capability** Bidders offering to provide the service (for example, reserves) must demonstrate that they are able to meet the technical requirements for providing the service, either physical or contracted.
- **Contract form** Contracts have a similar form to the reliability contracts, in that they guarantee an option fee to the chosen sellers, and specify a strike price at which the services will be guaranteed (indexed to the underlying fuel, where applicable).
- **Competition** A competitive procedure, probably an auction, would be used to select the companies to provide the service and to set the market-clearing option fee.

There are many variations on this proposal and they correspond to those we outlined for the reliability contract.

- **Centralized or decentralized.** This market will probably be managed centrally by the system operator. However, the latter may hold different auctions for areas of the system that are separated by important transmission constraints, for instance in the two parts of the British electricity market – England and Wales, and Scotland.
- **Whether the market is open to all technologies.** The bidders must be able to demonstrate their ability to meet the specific reserve requirements, so some technologies may be eligible for certain services and not others. For instance, demand response has a particularly important role to play in meeting limited duration reserve requirements, but may not be able to provide demand reduction for longer periods.
- **Contract length** The length of contracts is likely to be much shorter than for reliability contracts (which are designed to encourage investment) and may be offered in very short-term markets, such as balancing markets.
- **Secondary markets for reserve services.** This is an option worth exploring.

Summary on wholesale electricity market reform proposals

There are serious challenges facing EU electricity markets, especially as they cope with the implications of climate change and, in particular, the growing role of intermittent renewables. An important part of the answer to the challenges described above is to improve the operation of existing spot wholesale electricity markets, including ancillary service markets. A second important reform is to create new markets for long-term reliability services. A third reform is to realize the integration of existing wholesale energy markets through the building of economically justified interconnectors. Government plays a key role, especially in setting up, reforming, and regulating these markets, but there is no presumption that government will decide on the choice of technology.

CO_2 market challenges

Decarbonization requires more effective markets for trading CO_2. Although the authors are sceptical about the ability of carbon markets to act as the sole instrument for bringing forward low-carbon investment, it is likely that improved carbon markets, along with the other market changes suggested above, could combine to create the necessary framework conditions to make such investment in the EU attractive.

The EU's own policy with respect to climate change begins with the EU ETS. This emissions trading scheme has two fundamental objectives: one is to set a target to reduce emissions for the largest emitting industries (which amount to about 40 per cent of total emissions), and the other is to set a CO_2 emissions price that will drive short-term operating decisions (for example, whether to generate using coal or gas) and long-term investment (such as the encouragement of investment in low-carbon technologies). The ETS has contributed to the EU's success in meeting its commitments to reduce CO_2 emissions, although the economic recession has played an even more important role. The EU ETS has also been successful in providing short-term signals for operations – generators will include the price of CO_2 emissions as one of the operating costs that determines their bidding into electricity spot markets. However, the EU ETS has been unsuccessful in providing the necessary signals for low-carbon investment; the level of

current prices for EU emission allowances (EUAs) is far too low, and the volatility of price has been too high, to drive low-carbon investment.

In an earlier part of this study, we identified one mechanism that could send the necessary signals for investors: carbon intensity targets and related markets. Below, we identify some other mechanisms that could operate in parallel, or if necessary on their own.

Proposal 1: Reduce, eliminate, or 'neutralize' technology specific quotas

One of the problems that have distorted the EU ETS is the parallel policy of establishing quotas for renewable energy. No one doubts that renewable energy and energy conservation will play a role in the reduction of CO_2 emissions. However, the EU introduced quotas for renewable energy without adequately tightening the CO_2 emission target. The result has been to reduce the demand and the price for emission allowances, because renewable energy has replaced energy from fossil fuels that would have otherwise been required to buy allowances.

There are different ways to remedy this distortion. One is to reduce or even eliminate technology-specific quotas for future investment, while leaving intact any obligations already entered into. An alternative would be to neutralize the impact of quotas on ETS prices through an adjustment (in other words, a tightening) of the EU's own emission targets.

Proposal 2: Manage the price of EUAs

In the absence of a clear obligation to cut emissions (as would be provided by a carbon intensity target), investors in the electricity sector have no reason to commit to low-carbon technologies if there is no clear signal that CO_2 prices will reach levels that warrant such investment. Prices of allowances are very volatile and particularly subject to economic cycles, with the recent recession accounting for much of the downward pressure on EUA prices. Even if today's prices of less than €10/tCO_2 are not expected

to last, they are so low that key investors have publicly stated that they consider the EU ETS to be virtually irrelevant as far as investment decisions are concerned.

There is broad agreement in the EU, with large industrial consumers being the main dissenters, that some reform is required if the EU ETS is to be saved. Large parts of the electricity sector, the financial sector, industry with an interest in low-carbon technologies, and key Ministries of Energy, Environment, and Finance favour a higher and rising EU ETS price. Each has their own reason, with the electricity sector and engineering companies heavily committed (financially) to the decarbonization agenda, the financial sector benefiting from the significant investment and trading opportunities, and Ministries of Finance eyeing the revenues from CO_2 allowance auctions.

Here are two of the proposals on the table to manage upwards the price of the EU ETS allowances.

- R**ising carbon price floor** The UK has already introduced a carbon tax that effectively guarantees a rising carbon price floor – from £16/tCO_2 in 2013 to £70/tCO_2 in 2030. This poses problems when it is introduced in only one country, but at least it is a model to consider. If it were to be introduced throughout the EU (a very big if), it could provide the long-term signal investors are seeking. The greatest challenge – assuming a carbon tax or price floor could be agreed by EU Member States – would be to convince investors that the tax would not be changed. One possible way forward would be to provide long-term contractual guarantees, in other words to introduce contractual obligations that could not be ignored by future governments.
- **Central banking** A second approach is to manage the EU ETS price either through a central banking arrangement, or to have automatic 'adjustments' that would change the supply of allowances to reflect prices. In other words, if prices were to fall below some target level, supply would be removed from the market either automatically (with a formula) or through an organized carbon banking operation.

Both of these ideas (a rising carbon price floor and a management mechanism) involve a fundamental rethink about the EU ETS, whereas the debate currently revolves around two other operational options within the current structure. One involves 'setting aside' 1.4 billion allowances to reflect the current recession. A second is to tighten the

emissions target to 25 per cent below 1990 levels, instead of 20 per cent below. Both of these would raise the CO_2 price, but neither of them would address the fundamental problem of uncertainty about future price levels.

Conclusion

This part of the study has identified a number of ways in which electricity and carbon markets could be extended or improved to achieve the objectives of resource adequacy, decarbonization, and economic efficiency. In all of them, government has an important role to play but need not determine the choice of technology or the timing or location of investments.

We identify four areas for reform of wholesale electricity markets: improvement of short-term energy markets; introducing obligations on buyers to contract for capacity to meet resource adequacy targets; introducing obligations on buyers to contract for low-carbon resources to help meet decarbonization goals; and introducing obligations for the system operator to contract for reserve services. The quantitative obligations must be met through competitive processes, and would include both supply- and demand-side alternatives.

For the carbon market, the priorities are: to eliminate distortions in the existing EU ETS; and to introduce a mechanism that would provide greater certainty about future carbon prices.

Overall, while a package including the sorts of improvements listed above would undoubtedly help improve market signals and give better incentives for investment in low-carbon generation and conventional generation, not all the reforms are equally realistic. Most of the identified reforms to the short-term markets are relatively straightforward or have been implemented in one or more jurisdictions, even if they are controversial. Introducing quantity-based obligations and markets for capacity and ancillary services may be more challenging, but these have been introduced already in some EU countries and are under consideration in others. However, the prospects for improving long-term signals for low-carbon investments in the EU ETS are arguably less favourable in current circumstances.

Furthermore, there is no guarantee that the changes suggested above, even if all were implemented together, would bring forward the required amounts of carbon generation at a fast enough rate. Apart from anything else, the uncertainties produced by the scale of some of the suggested changes could create a hiatus in investment as the implications are absorbed and add to future uncertainty – how would an investor know that a government (or its successor) might not decide on further tinkering with the markets?

Part 5: The role of demand in a decarbonized electricity system

Introduction

As discussed in Part 1, electricity is the chosen sector for achieving the bulk of carbon emissions reductions, among other reasons, because there are existing low-carbon technologies for power generation which can be installed upstream without consumers having to change all their equipment or their behaviour. This makes it sound a fairly simple process (and in comparison with other sectors, perhaps it is). But for the electricity sector itself the longer-term implications are profound – as set out in this part of the study, they effectively turn upside down nearly all conventional views of the industry – and these implications will not leave electricity consumers unaffected. Indeed, in some ways the most profound changes of all will come in the relationship between the consumer and the industry, changes which are at present only imperfectly understood but which will nonetheless determine the future operation of the industry and the provision of electricity services, which underpin modern civilization. While the precise destination is unclear, the direction in which the system is moving is apparent, and any market reforms will have to be able to accommodate this trend, and in particular the changing role of demand (broadly defined) in a decarbonized system.

An industry turned upside down

In fact, the electricity system is set to undergo such profound changes that it will become virtually unrecognizable from a twentieth century perspective. The change will not happen overnight – indeed, it is likely to take decades rather than years for the full implications to become clear – but it will affect virtually all aspects of the industry and its users. The primary driving forces are decarbonization on the one hand and developments in information and communication technology on the other. Some of the likely changes are listed below.

Operating characteristics

First, the operating characteristics of the system will change, as illustrated in the three charts in the first annex to Part 6 of this study (Annex 1). The first shows how demand is met across the year at present, with a straightforward 'stack' of different plants rising from nuclear at the bottom on baseload, generating most of the time, up through fossil plant and other sources to wind at the top, forming the icing on the cake. Although demand across the year varies, the pattern for each day is broadly similar. The second chart shows what the impact of wind power might be by the mid 2020s. This chart is much more complicated. Wind power is sometimes far and away the main system source, sometimes quite minor. The position varies quite rapidly even in the short term as shown in the third chart, which looks at variation across a single week in 2025.

Cost structure

The cost structure of the industry will also change to reflect this different structure of generation, and over time this will have to be reflected in the structure of prices; indeed our whole view of the product created by electricity producers may need to be revised. At present, the industry is viewed essentially as the producer of kilowatt-hours and prices are set largely on the basis of the cost of production of the marginal kilowatt-hour. This reflects the present broad cost structure of the industry. However, as electricity systems decarbonize, the adequacy of a kWh approach will come into question because of the intermittency, inflexibility, and/or capital intensity of the new sources. The costs of balancing the system and providing ancillary services will increase, while the cost of producing the marginal kWh will go down, in some cases to zero. The providers of these services may also change – and the demand side may be best placed to provide them. Part 6 discusses these issues in more detail; Annex 2 looks at the possible impacts on wholesale markets.

Planning and operations

The planning and operations of the industry will also need to change. Traditionally, the industry has operated on a 'predict and provide' basis. Whether in planning for the next day or for some years ahead, essentially the same process has been employed. System planners forecast what they expect demand to be for, say, the day ahead or seven years ahead; then they do what they can to ensure that sufficient capacity is available to meet that demand. For the day ahead, they match generation and demand forecasts and

ensure, through exchange trading and the balancing system (in the case of the UK), that the two match for each half hour of the day. When looking years ahead, centralized markets use forecasts to plan their investment strategies; liberalized markets use the information to guide private generators in their investment programmes – where the forecasts show a deficit in capacity as compared with demand there should be incentives to build new capacity. But in both cases the starting point is basically the same – demand is largely a given; it is supply that provides most of the flexibility.

In the future, this is likely to change for a number of reasons:

- **Supply will become more inflexible** for economic and operational reasons. First, the new cost structure indicated above will make it more expensive for most plant to provide flexibility – many renewables are inherently inflexible. Nuclear plant has traditionally not had to provide flexibility. While it is possible for it to do so, there are cost implications from lower load factor operation of high capital cost plant, and from the (high) costs of starts and stops. Similar arguments apply to CCS plants.
- Control, aggregation, and coordination of **demand side flexibility will become cheaper** because of the development of information and communication technology. Already in the USA, there has been a growth of 'demand aggregators' who group together different loads capable of adjusting their demand at short notice. In the future not only will such aggregation become easier but there will also be significant development of the communication and control mechanisms which signal the need for demand reduction, and in some cases implement it on a customer's premises. At present, one main reason why demand response is confined to fairly limited segments of the market is that there are few incentives in the pricing systems for most consumers, particularly residential customers. But the cost of giving such price signals, and of installing automatic controls which can respond to price signals, is set to fall rapidly with the development of smart grids, smart meters, and home automation systems as discussed below.
- **New forms of demand**, which will create new challenges for system management, will develop, such as electric vehicles (EVs). Synergies may be possible between these new loads, provided flexibility is built into the recharging arrangements, and the increasingly intermittent sources of power. For

instance, a recent study of the New Zealand power system noted that it experiences large frequency fluctuations which are expected to increase because of the increasing penetration of wind power and the charging needs of electric vehicles. But the chapter concludes that 'there is … a great opportunity to reduce wind and EV integration costs by coordinating the charging of EVs with the variation of wind generation output.' (Sioshansi 2012a, chapter 18).

- **New forms of distributed generation**, such as solar PV panels on roofs, will effectively appear as 'negative demand' from the point of view of the system. The declining cost of distributed generation will make this form of supply increasingly important.

All these developments will change the balance between supply and demand flexibility – in future it may be as much a matter of forecasting supply and adjusting demand as the reverse – if (and it is a big if) the pricing, regulatory, customer friendliness, and other elements of the system are all in place.

Storage

Storage is also likely to play a greater part in the future electricity system, for reasons similar to those given above; flexibility will have a higher value in that system. Furthermore, there are many benefits in having storage as close as possible to the consumer (ideally, on consumers' premises). This decreases risk and increases security; reduces the need for transmission and distribution capacity; and can serve to extend consumer choice and control in relation to the value and amount of security they need. But current systems are not well designed for this – there are various regulatory and pricing obstacles which reduce the incentives for customers and independent providers to create storage capacity. A recent analysis concludes that:

> Although technical issues, such as manufacturing costs and device efficiency, are often listed as barriers to storage development, numerous policy and market issues are also deterrents. This includes incomplete valuation of the full benefits that storage can provide, the regulatory treatment of storage, and risks associated with storage development. Sioshansi et al. (2012b).

Smart grids

Smart grids are obviously going to be a central component of the future electricity system, whether or not decarbonization goes at the pace intended by governments. But they will be particularly important for decarbonized systems. They will facilitate the integration of intermittent sources such as renewables, of demand response and distributed generation, and of the management of new loads such as EVs. Perhaps most fundamentally they will change the whole nature of the transmission and distribution system. In the words of one recent study smart grids:

> … must ultimately turn the grid from a historically one-way conduit that delivers electrons from large central stations to load centres, to a two-way, intelligent conduit, allowing power flows in different directions, at different times, from different sources to different sinks. Sioshansi (2012a Introduction).

But, as another study in the same collection points out:

> Smart grid is a lot more than just technology … The changes we've seen to date have been largely motivated by engineers and technologists … True change will require full participation from economists, lawyers, policy experts, financial experts and many others. op cit (Chapter 4).

Many would add customers as perhaps the most important group on that list.

Control and dispatch

An important part of this development could be a change in the industry's control and dispatch arrangements. In the past this has been the responsibility of the grid or system operator, operating from a central dispatch centre and controlling the operation of the large power stations that provide the bulk of power. In the future, much of the operation will be controlled at the periphery – distributed power, demand response, new flexible loads like EVs etc. will be too small to be dispatched from a single centre. Nonetheless, they will have to be coordinated through the new smart grids, as described above. But this will pose major new operational, economic, and regulatory challenges as the system becomes more diverse and decentralized. In the new system:

> In order to exploit the advantages of distributed generation (including renewable energy sources) it is necessary to follow a 'system approach': distributed generation will not feed into the network in a stand-alone mode but will be fully integrated … Distributed generation will be dispatched accordingly and the distributed generators will have to provide ancillary services to the network and will become normal market participants. Hadjsaid and Sabonnadière (2012).

This will significantly change the complexity of the system and associated market structures and control procedures.

Smart customers

One implication of all the above developments is that there will be a more active and responsive demand-side. The changes can be summed up in the expression 'smart customers' – the industry's clients will no longer be passive recipients of system output (consumers), but active participants in system operation and control (customers). Precisely what this means remains unclear, as discussed below. Customers may choose, or be allowed, to exercise this new role in a variety of ways, and there are major implications for the development of metering, pricing, regulation, and other aspects of the system.

There is no room within the scope of this study to look in detail at all the changes listed above, though perhaps the key challenge is that of customer empowerment for demand response, looked at in more detail below. The main message from the above discussion is that electricity is set to undergo major changes which will overturn many fundamental aspects of the present system; that the implications of these changes are as yet imperfectly understood; but that they involve much more than just technology – they will require major changes in pricing, regulation, operation, and other aspects of the system and in the role of all the players, from producers through system operators to consumers (customers) themselves. The challenge for governments is to ensure that new opportunities are not foregone and potential efficiencies lost because the systems they set up to effect the transition to a low-carbon system inhibit the emergence of a flexible and effective low-carbon system for the longer term – one which is capable of coping with all these fundamental changes. The transition will inevitably be difficult and expensive, and it is important that policy makers ensure that all opportunities can be taken to reduce the costs involved; and that they consider how customers fit into the new systems and are able to play the most effective role.

Demand response

It is clear from the above discussion that the future electricity system will give a larger role to demand response (DR) in the widest sense (including distributed generation, consumer storage, consumer actions to switch or reduce demand etc. – in other words, to operations taking place at the periphery rather than the centre of the system).

Indeed, demand response can directly and effectively respond to many of the system challenges mentioned above. A review of US programmes in this area concluded that:

> Demand response is a perfect complement to the increased penetration of wind energy … Fuel costs can be avoided … O&M costs are also reduced because maintenance schedules for fossil-fuel power plants are determined by how much cycling a plant does through its capacity range … Customer costs can be reduced … Emissions are also reduced. Sioshansi (2012a, Chapter 10) .

DR is not an entirely new idea, but for a number of reasons it has not developed into a major component of most systems. In traditional power systems that rely primarily on fossil fuels to meet peak demand, the fundamental role of DR is to reduce peak demand, normally through shifting that demand to off-peak periods. With existing generation plant, load-shifting can lower the system's short-term energy costs by avoiding the need to despatch more expensive peaking plants. In the longer term, it lowers the system's capital costs by postponing or avoiding investment in peaking power plants, as well as in transmission and distribution networks. DR can thus contribute to the reduction of system costs in the short-term and the long-term.

In the UK and other countries DR has focused on large, energy-intensive industrial consumers, where the scale of demand has justified their active participation. Although commercial and residential customers participate in DR – for example through time of use tariffs and demand charges that limit peak demand – their economic significance has been relatively limited (though, as discussed below, some pilot studies in the USA and Canada suggest that peak demand, at least among participating customers, can be reduced substantially).

One reason for the relatively limited significance of DR to date is that there are many barriers to DR in traditional power systems. Among these have been pricing structures, especially for smaller customers. Tariffs in regulated systems, and prices in competitive ones, usually do not reflect short-term system marginal costs and hence do not give incentives to customers to change their demand patterns. Retail companies may have no incentive to pass on wholesale market price signals due to the practice of customer 'profiling', whereby all customers of a certain type are assumed to have the same demand profile. The absence of hourly metering in most systems is also, of course, a barrier since a consumer's actual demand is not metered in real time. Furthermore, tariffs for smaller customers often have no fixed charge related to contracted peak demand, and hence do not send a signal that encourages customers to lower their peak demand. Finally, the transactions costs of DR are often higher than the potential savings for smaller customers; the fact that there are virtually no aggregators of small customer demand is a reflection of this.

At a wider level, markets have only rarely been organized to facilitate DR. In particular, there have been few instances where demand has been encouraged or allowed to compete directly with new generation sources in organized markets, though where this has been done the response has often been significant – for instance, the PJM interconnection has recently expanded the range of its demand response products in response to a six-fold increase in the supply of such capacity. Sioshansi (2012a, Chapter 17).

As electricity systems move towards decarbonization, traditional forms of DR will continue to be important, but DR is likely to take on a new significance and play a wider role. Whereas the traditional form of DR was mainly about shifting demand from the peak, new forms of DR help to lower system costs by providing short- and medium-term flexibility – both through reductions and increases in demand. There is potential for a substantially greater use of DR in the provision of a wider range of flexibility services. Indeed, as a growing share of generation becomes inflexible and/or subject to intermittency, DR could take on a critical role as far as system costs and stability are concerned.

Importance of demand response

DR is likely to be particularly important, but also particularly complex, in the UK, for a number of reasons:

- **Urgency** The UK is moving faster to a low-carbon system than almost any other country, partly because of its own self-imposed targets, partly because of the extremely ambitious EU renewables targets. It will also need to replace significant amounts of capacity in a relatively short time because of the ageing of existing plant and the impact of the Large Combustion Plant Directive and the Industrial Emissions Directive.
- **Availability of alternatives** The UK has very limited potential for developing hydro power (a flexible source of regulating power in many other systems) and – unlike, say, Germany – does not plan to replace the coal-fired generation which provides the main source of flexibility in the existing system. As an island it also faces more limited interconnection opportunities than mainland Europe.
- **Form of competition** The UK market is in many ways the most competitive in Europe. The implications for demand response are, however, complex. In particular, aggregation within an unbundled market structure involves significant complication and transaction cost. This is true horizontally – it is difficult to aggregate loads across suppliers to create significant volumes of demand response; and also vertically – suppliers provide the direct interface with customers but savings from demand response extend across the whole system (generation, transmission, and distribution). Furthermore, retail suppliers currently have limited incentive to understand or manage customer demand because of the profiling system which estimates customer usage; and they may in any event be reluctant to make any investment in this area because of the ability of customers to switch with little notice. The introduction of smart meters will enable some of these issues to be addressed, but as yet the 'benefits realization programme' is undeveloped.
- **EMR developments** While the details of the EMR remain to be formulated, it is clear that its broad shape is driven by the needs of investors in generation and the wish to lower risks for them by shielding them from direct exposure to market prices. It is likely that this will reduce the incentive on such generators to provide flexibility (despite the CfD element in contracts). The overall effect of decarbonization is in any event to raise prices to consumers, so the scope for cost-effective demand reduction by consumers should increase.

Demand response models

So the importance of demand response in the future system, particularly in the UK, seems clear; less clear, however, is what form that demand response might take.

There are many possible models:

- **Utility controlled** This refers to measures which are in some way controlled by the utility and used by them to help balance the system. In the UK, traditional off-peak heating fell largely into this category. It was designed to reduce costs for the utility, and was provided and metered (and in some cases directly controlled) by them. Incentives for creating such options will increase as the proportion of variable generation increases and may be of particular value in relation to very short-term balancing actions. A recent study of 'Direct Load Control' (DLC), as it is called, concludes that 'instantaneously dispatchable DLC offers the greatest value on the regulation and spinning reserves timescale.' (Sioshansi 2012a, Chapter 9) In other words, DLC can substitute fairly directly for dispatchable supply sources and is thus very convenient from a utility perspective. But there are obvious problems from a consumer perspective, making this less suitable in many cases for residential consumers and more suited to industrial and commercial demand. For instance, there are the privacy and 'Big Brother' issues involved in ceding control of your appliances to a utility; for a residential consumer it is also often difficult to know when you will have most need of a particular service and when you can forego that service.
- **Customer controlled** At the other extreme are customer-controlled responses. These are often taken as the starting point for demand response via the use of smart meters. It is hoped that such meters will give a more accurate and timely picture of the cost of particular energy services, enabling consumers to respond by improved efficiency or better control of service use. However, again this raises significant questions about consumer psychology and behaviour. In practice there is no strong evidence of significant demand reduction merely from the introduction of smart meters. A recent overview of the topic, for instance, concludes that:

  > There is still uncertainty about the size of the demand response benefits … Smart metering will facilitate a new and much more active role for energy customers in the coming decades. The extent to which this new role will translate into energy and cost savings remains to be studied. Jamasb and Pollitt (2011).

To have an impact, such metering needs to be reinforced by better understanding of customer psychology and the sort of information needed to produce a behavioural response on the one hand; and by pricing, regulatory, and other external structures on the other. There is some evidence from so-called Critical Peak Pricing studies that significant reductions in peak demand on the part of individual consumers are possible if strong enough price signals are given. However, these programmes are largely experimental and focused on particular groups of consumer. It is not clear how widely the findings from such studies can be extended. For instance, the conclusion of one survey was that:

> The programs under study were reported to achieve 12–33 per cent aggregate load reduction across a wide range of prices. Only one program was able to generate a load reduction of more than 1 per cent of the utility system peak. Albadi and Saadany (2007).

- **Set and forget** This sort of measure represents a sort of halfway house. There are many possible variants of this approach. At its most developed it involves the installation of a home automation system complemented by smart electrical devices – appliances which can be controlled by the automation system. The consumer can then set and adjust a set of rules for the automation system which will control how their appliances will respond in particular situations (or leave in place a manufacturer's pre-set response). For example, the system may allow a night time setting which would check that doors and windows are closed, unwanted appliances turned off, and other appliances, such as a dishwasher, set to run at a time when energy prices are low. Again, such approaches are experimental; they are also costly in terms of investment. While they offer considerable benefits for the consumer, it is not clear whether they will be the dominant form of demand response. Yet to work effectively they probably depend on network and coordination effects – in other words, appliances have to be available equipped with standardized control devices capable of responding to the system's instructions; the cost of this capability will depend heavily on whether there are sufficient economies of scale (which might require regulation) to make the systems viable, as well as on whether pricing systems are sufficiently flexible to give the appropriate incentives.
- **Aggregators** Much of the present demand response potential in the USA comes from so-called aggregators, who act as intermediaries between utilities and their customers. They identify controllable loads; help customers with control devices; receive information about the status of the power system; and provide load control

for the system at critical times, sharing the savings with their customers. This sort of approach may not work so well in fully competitive and unbundled systems, and may in any event be a form of transition, helping create a market which previously was lacking, and it is not clear how far it represents a viable long-term form of demand response. Nonetheless, it is likely to be of considerable significance in the short- to medium-term.

- **Microgrids** This refers to small grids containing a set of controllable distributed generation, storage, and demand-side resources, usually with a significant contribution from renewable technologies and DR, which operate in a semi- (or fully) autonomous manner. In other words, such a grid may be connected to the main utility grid but can also operate as an island (Sioshansi 2012a, Chapter 8). They can therefore interact with the main grid in a flexible and responsive manner, importing or exporting power as appropriate. The advantage of such microgrids is that the combination of physical proximity and integrated operation simplifies the planning, development, and control aspects for the microgrid operator, while expanding the scope of operations beyond a single premises allows greater flexibility and an ability to balance non-coincident loads and sources. It is not clear how large the overall scope is for such arrangements but potential users might be, for example, university campuses or industrial parks. Here there might be possible combinations of renewable sources (such as wind or biomass), local backup (such as a gas turbine), along with various forms of demand response – for example, the ability to turn down heating, lighting, and cooling across a set of premises in predefined circumstances.
- **Smart communities** This can refer to various forms of community-based energy initiatives, usually less fully autonomous than microgrids but sharing many of the same characteristics: community-based arrangements mixing supply- and demand-side options at local level with the aim of producing more sustainable energy systems.

Uncertainties associated with demand response

Even the above brief description of some of the options indicates the range of uncertainties, the questions remaining to be answered, and the complicated set of interconnections between the different aspects of the issue. For instance, it is clear that stronger demand response will require pricing signals. These could include time-of-use

pricing set by the utility, critical peak pricing as described above, direct access to real time market prices, or other options. But each of these options in turn raises various sets of questions:

- **Ethical**. It is arguable (and has in the past been the basis of UK-regulated pricing) that cost-reflective pricing is the most ethical approach, since other methodologies involve one group of consumers in subsidizing another. Some of the approaches mentioned (in particular, critical peak pricing) may therefore be open to criticism from this perspective. More generally, the cost of smart metering, smart grids, etc. will have to be borne by consumers – but the benefits may not be spread equally. In particular, consumers with the initiative and ability to invest in smart appliances and adjust their consumption may be able to secure the main share of the benefits, leaving less flexible or poorer consumers bearing their share of the cost without corresponding benefits.
- **Political** The ethical arguments overlap with more purely political issues. The move to decarbonization will inevitably increase electricity prices. Demand response may enhance customers' ability to control costs, but at least initially it will require investment and may prove an unpopular extra burden on consumers. There are some signs that this is happening in the UK today – the Public Accounts Committee in its report on smart meters, for instance, has complained that:

  > Consumers will have to pay energy suppliers for the costs of installing smart meters through their energy bills, but many of the benefits will pass in the first instance to the energy suppliers … The Department needs to ensure that the vulnerable, those on low incomes and those who use prepayment meters also benefit from smart meters. It would be unacceptable if these consumers bore the costs of smart meters through higher charges without getting a share of the potential benefits. (PAC 2012)

  Managing the process politically will be an essential part of the transition to a low-carbon system.
- **Regulatory** As noted at a number of points above, regulation will need to develop to reflect the various new challenges. Demand response is at present very much an afterthought in the government's EMR proposals, and it has only a limited place in infrastructure tariff regulation. Nor are some of the new developments suggested above, such as microgrids, easy to incorporate in existing regulatory systems.
- **Cybersecurity and privacy issues** Depending on its precise form, demand response could raise significant issues of cybersecurity and privacy which need to be clarified

before the limitations imposed by these considerations can be properly assessed. In competitive markets there are also significant problems of commercial confidentiality. Competing suppliers may not want to share information about their customers with third parties such as aggregators; the network operator may similarly be unwilling to share information about the status of the system with a wide range of participants; there may also be regulatory barriers to the use of customer information.

- **Interdependences** It is clear that there are strong interactions and interdependences between different parts of the system. Smart meters will only reach their full potential if combined with smart grids, smart appliances, and new approaches to pricing. But this will require significant infrastructure development, standardization of approaches to controllable appliances, and so on. These in turn will require not only time and expense (and raise the ethical and political questions noted above) but will also depend on the developing level and understanding of customer psychology, behaviour, and preferences. These issues are of course subject to ongoing programmes of research by governments, utilities, and such bodies such as the National Energy Foundation but inevitably it is difficult to get definitive results when the various other elements of the picture are not yet in place.
- **Path dependence** There are many elements of path dependence here – for instance, the smart meters now being rolled out should have a lifetime of decades. Yet they are in many ways fairly simple versions of the technology, designed mainly to give better information rather than, for instance, to provide two-way communication and control. Development of smart appliances and home automation is likely to require a new generation of meters and, as the present roll-out is likely to last over most of this decade, it will be some time before a new generation can be contemplated. More generally, the various different routes to demand response listed above are likely to be associated with different approaches in terms of regulation, industry, and market structure.
- **Lack of incentives and transaction costs** As noted above, with an EMR approach, the incentives promoting demand response are blunted; price signals within the system are smoothed through the System Operator and it is not clear at this stage what incentives consumers or suppliers will have to invest in demand response. Furthermore, the benefits of demand response (as noted above in relation to storage) potentially accrue to all levels of the system – costs can be saved in generation,

transmission, distribution, and system balancing. Within a fully integrated system, all these savings can be captured by the single supplier. With the UK liberalized system, a variety of players are involved, some with regulated prices, some facing market prices, some facing EMR affected prices, and the transaction costs and internal inconsistencies this creates will make the aggregation of the different elements of saving very difficult both horizontally (in aggregating different customers within a network area, who may have a number of different suppliers) and vertically (in aggregating the savings at different levels of the system).

A summary of the position of demand response

In short, despite the clear potential and importance of demand response, the form or forms it will take remain uncertain and there are many obstacles at present in the way, not just of developing the full potential of DR but even of seeing what that full potential might be and where it might best be realized. What does seem clear is that there is a risk that the EMR proposals might serve to restrict and obscure that potential; in the shorter term by blunting price signals and reducing the incentives for DR; in the longer term by creating an over-centralized and inherently unresponsive system based on centrally determined long-term contracts which will reduce flexibility, incentives for innovation and risk-taking, and customer responsiveness.

Conclusion

The central issue is whether alternatives which would improve price signals and incentives are available. It can be argued that all the options discussed in earlier parts do in fact achieve this. A more consistent version of the single-buyer approach would help to reduce the transaction costs and incentives problem; the single buyer (Part 2) would have an overview of the whole system and incentives to reduce overall system costs and to develop pricing systems which would ensure the appropriate signals. A more sophisticated approach to wholesale markets and their pricing structures (Part 4) could ensure the right signals at that level, and encourage suppliers to reflect this in retail pricing. An intensity target (Part 3) would have the dual advantage of leaving flexibility for the development of new market structures and of encouraging demand response to compete on a level playing field with generation options.

But whichever approach is taken, it is clear that it will take some time for the necessary technical, regulatory, pricing, and consumer elements to fall into place. The main concern, while this process is still under way, must be to give encouragement and appropriate incentives for the development of demand response options, and to avoid saddling the industry with inflexible systems which would complicate or preclude these developments. The costs of such inflexible systems, in terms of inefficiencies and insecurities in the operation of a future low-carbon system, could be very high.

Part 6: The decarbonization roadmap – issues to be addressed en route

Previous parts of this study have looked mainly at the importance, and difficulty, of securing investment in low-carbon generation. But, as Part 5 indicates, decarbonization will affect the whole of the electricity sector and its interactions with electricity consumers, not just generation investment.

This final part of the study identifies a number of key issues arising out of discussions in earlier parts that will have to be addressed by governments if they are committed to the decarbonization of the electricity sector. They will at least need to consider the implications of these issues, but they may also decide that they have to set a direction and control the way forward, in order to ensure an efficient transition to decarbonization. The position they take will obviously depend on their policy goals, their attitude to the balance between markets and central control, the perception that investors have of political risk, and their starting points with respect to the carbon intensity of their economy. For the sake of simplicity, we will refer to the main two approaches that were outlined in the report as favouring 'centralization' (state-driven) or 'decentralization' (market-driven).

The general message is that there is more than one way to decarbonize the electricity sector, but that all governments will need to consider the same underlying issues as they do so. The UK has chosen one route, which reflects its rigorous emissions targets, its relatively high level of carbon intensity, the perception that significant amounts of low-carbon investment are urgently required due to the imminent closure of many of its conventional plants, and because it is an island system. Other countries (such as Germany) may share a similar point of departure with the UK on carbon intensity, but have more time to make the transition and be more fully integrated into regional markets. Others (such as France) will begin with relatively low levels of carbon intensity, close integration with the electricity networks of other countries, and a respected tradition of planning. And there will be some that begin with relatively low carbon intensity, limited integration into the rest of Europe, and little investor confidence in the stability of regulation (Spain, for example). Each of these different

characteristics will influence the choice of the decarbonization route. But whatever the starting point, governments committed to decarbonization will have to address all the issues we analyse below. They will also have to do so within the limits of EU legislation, for instance on matters such as electricity sector liberalization, competition (issues relating to state aid, for example), energy and environmental policy (such as the EU ETS), and the Single Market.

For each policy issue, we identify the key points and some of the policy choices that governments face. We have divided these issues into five main categories, while Annex 2 looks in more detail at wholesale market design:

A. Planning and investment
B. Operation of a low-carbon electricity system
C. The role of the demand side of the market
D. Competition
E. Regulatory and institutional arrangements

Planning and investment

Earlier parts of this study have looked at ways of promoting low-carbon generation investment. Various options have been identified, involving greater or lesser degrees of central control. But in addition to these specific generation-related issues there are wider questions of system planning and the extent to which this needs to be coordinated centrally.

There are elements in the development of a low-carbon power sector that prima facie call for a substantial coordination of investments. The most obvious is the coordination of transmission investment with the development of renewable resources that are wholly or highly location specific, for example offshore wind. Equally important is ensuring the technical feasibility of the emerging combination of the various types of low-carbon plant (the issue of intermittent generation from wind and relatively inflexible nuclear generation) and considering the effects of new types of demand (such as demand response using battery storage) that mitigate the problems of inflexible or intermittent generation. Coordination may also be necessary to achieve sufficient diversity of sites to

increase the reliable capacity contribution of wind generation, and to minimize the requirement for fossil fuel backup. Increasingly, some of these questions will require regional (or EU-wide) coordination between countries/systems, either in terms of coordinated planning or in terms of common market rules, or both.

The precise forms of planning needed to achieve the required level of coordination will, to a large extent, be determined empirically and pragmatically. Substantial network investments, such as those in offshore wind development or in CO_2 gathering pipelines, prima facie demand a degree of prescriptive planning to design a network of efficient linkages at minimum cost. For a single country or network, this task might fall to the network (system) operator, but where a plurality of system operators is involved there is likely to be either a further prescriptive overall plan to which the separate operators adhere, or alternatively a forum in which the system operators seek to agree a programme that maximizes their mutual benefit.[19] Such a forum is in any case likely to be required to deal with the commercial arrangements pertaining to the operation of these super networks, the ownership responsibilities, and the allocation of costs and benefits from the network investment. One might expect the EU to have a role in this, in respect of trade and the internal market issues that will be generated within a super network, but not to operate as a planning authority in its own right.

The balance of investments in generation capacity carries much less of a requirement for formal prescriptive planning. But governments will need to decide whether and how to coordinate generation investments, for example to ensure that systems do not rely on excessive proportions of capacity in the form of intermittent power, or on inflexible nuclear plant, and to ensure that these can be balanced with adequate storage and flexible generation or non-instantaneous loads. This coordination does not necessarily imply the need for detailed prescriptive planning. Exactly how this coordination should be achieved is closely bound up with the structure of the industry and the instruments chosen to implement decarbonization policy.

[19] Perhaps building on The European Network of Transmission System Operators for electricity (ENTSO). Also, the North Seas Countries Offshore Grid Initiative (NSCOGI) aims to connect ten countries with a huge network of wind farms and interconnectors.

Indicative planning for generation could take the form of a system operator signalling expectations as to future demand and feasible combinations of new low-carbon capacity, along the lines of the forward-looking statements currently produced in the UK by the National Grid, but with individual companies still making their own choices on new capacity. Alternatively, the process could be managed through a central purchasing agency, possibly jointly owned by suppliers, setting out quotas for different types of capacity, and taking greater or lesser amounts of responsibility for technology choices and the timing of new capacity, or it might be organized through a combination of central purchasing (for low-carbon electricity and backup reserves, for example) and decentralized company decisions.

Timing of investment

Whatever approach is taken, there is likely to be a difficult question of timing. There is often a prima facie case for postponing irreversible decisions in order to wait on better information (although this must also depend empirically both on the degree of irreversibility, and the costs and benefits associated with taking action now, compared to those of waiting). This gives rise to the question: is there an option value associated with action versus delay on the road to decarbonization?

The big problem in this context is that there is a serious mismatch between a perspective based on the global problem, and a perspective based on the interests of investors (in new capacity) or of nation states considering their individual energy and decarbonization policies.

From a global perspective, it is decisions for continued use of CO_2-emitting fuel that are most clearly irreversible;[20] CO_2 concentration in the atmosphere is, on current perspectives, both cumulative and irreversible. Reduction of current emissions, viewed in global terms, postpones the dates at which concentrations reach particular levels, and so delays the onset of adverse climate consequences. This allows more time both to

[20] In the absence of realistic prospects for the development of practical techniques for extracting CO_2 from the atmosphere at a large scale and acceptable cost.

develop technology-based solutions to eliminate emissions, and to plan for measures of adaptation. It therefore has, prima facie, substantial positive option value.[21]

From a national or investor perspective, the opposite is true. The irreversibility for an investor in new generation capacity is most closely associated with the immediate capital expenditure, with the substantial risk that the revenues on which the case for the investment depends are put at risk by regulatory interventions or by changes in the market rules, or through additional capacity brought on line by suppliers. The investor has no means of gaining any portion of the real but intangible 'global value' of the investment; consequently a positive option value is more likely to result from postponing the investment decision, until regulatory uncertainties, national and global, are resolved. The value of waiting, and risk reduction, are particularly important to typical infrastructure investors (including pension funds and sovereign wealth funds) seeking modest but ultra low risk returns.

This is another expression of the 'market failure' associated with the externalities linked to CO_2 emissions and climate change. It provides a central argument for intervention in the electricity market to correct this failure, or to introduce a related policy (such as a CO_2 tax or a carbon intensity target) that will encourage decarbonization in the electricity sector. A significant requirement of electricity market reform is to remove the obstacle to private sector investment that stems from regulatory uncertainty, and hence to change the option value of delay that is perceived by the private investor.

In the UK context, the debate can be seen as the problem of how best to remove this asymmetry in option values, which currently inhibits not just low-carbon investment but any form of investment in new capacity. The question is therefore what package of measures will be sufficient to promote investment, and whether this can be done through adjustment to market rules (for example capacity payments) and price support (carbon tax or floor price for carbon) or whether a greater degree of intervention is justified, through the provision of long-term contracts, underwritten by government or a sufficiently secure group of purchasers.

[21] This and related issues are discussed in more detail in Rhys (2011).

Governments in countries that face less urgent investment requirements will have a wider array of policy instruments available to them and may have greater freedom to select more decentralized models.

Security of supply

Whether or not they adopt a centralized model of investment choice, governments will inevitably be concerned to ensure continued security of supply, and in particular resource adequacy, in the electricity system. Resource adequacy refers to the system's ability to meet demand with an acceptable level of reliability, as measured by expected outages. Normally, the concept refers to the amount of generation (or demand response) that is available to meet peak demand. Broadly speaking, the definition of what is an 'acceptable' level can be determined either by consumer preferences through a market, or by government, or an independent agency such as the system operator.

The energy-only market (which operates in most EU countries) is supposed to enable customers to make the decision about what constitutes resource adequacy. The idea is that in markets for most products and services, the level of supply 'adequacy' is determined by how much customers are willing to buy at a given price. In theory, electricity customers choose their acceptable level of resource adequacy by choosing to be cut off above a certain price (that reflects their value of lost load – VOLL). However, in practice today most electricity customers do not have the ability to respond in this way to price signals, and indeed do not have meters to measure when they consume. Consequently, these energy-only markets use approximations of the VOLL, and actual resource adequacy is being determined by those estimates, not by real customer preferences. As smart metering is more widely rolled out, customers will be able to choose the level of reliability they are willing to pay for. It is conceivable, for instance, that customers will choose to self-supply (from a battery, or even candles) rather than to buy electricity from the system when prices rise above a certain level.

The alternative to customer-driven resource adequacy is for the government, regulator, independent system operator, or other public agency to define reliability requirements (such as, for example, one outage event in ten years) and the planning reserve margin that will deliver that level of reliability, and then provide the necessary regulatory or

market framework to ensure they are met. For instance, government could take full responsibility for ensuring resource adequacy, through public ownership and investment, guaranteeing long-term contracts (via a single buyer), or by introducing capacity payments for generators, whose costs are recovered from customers. Alternatively, as in a number of US states, government may give obligations to retail companies to contract for sufficient capacity to meet their own customers' demand, with an acceptable reserve margin, and may organize central auctions to assist them in meeting their obligations.

Today, the debate in the EU is increasingly about what should be the combination of public intervention to determine acceptable levels of resource adequacy, and the nature of the mechanisms to achieve these objectives. Some EU governments, including the UK, have supported energy-only markets, but are now considering introducing capacity market mechanisms[22] to ensure sufficient conventional capacity to achieve explicit or implicit reserve targets. Others, like Spain, have administratively determined capacity payments, and are considering whether to adopt market mechanisms instead. Governments are also moving towards the development of mechanisms that will allow demand-side participation to meet long-term resource adequacy and to provide short-term reliability in the form of reserves to back up intermittent renewables.

These recent developments in the EU tend to involve a fairly heavy amount of government intervention in defining the amount of capacity required, but also potentially in choosing the mix of plants. One of the fundamental policy questions is whether the advent of smart metering and distributed generation will allow for more customer-driven approaches to determining resource adequacy. It would be ironic if governments were to abandon customer-driven models precisely when customers were in a position to express their preferences.

[22] In the case of the UK this means re-introducing capacity mechanisms. The original 1990 Pool had a VOLL element to it but this disappeared in the 2000 NETA 'reforms'.

Technology choices

In addition to ensuring that there are adequate levels of generation (and network) capacity, governments promoting decarbonization may also be concerned to guide technology choices. Indeed this issue will largely determine the success of the move to a low-carbon system – making the right technical choices will be critical to the speed and effectiveness of the process. But it is not obvious that it is the government that has to make these choices. Indeed, there is a risk that technology development can degenerate into a process of picking winners, and assume such importance that it takes priority over the ultimate goal – to reduce emissions from electricity generation in the most efficient manner. It is arguable that this is already happening in some countries – such as Germany and the UK. In Germany, it sometimes appears that the objectives of promoting renewables on the one hand, and phasing out nuclear on the other – rather than the carbon consequences – have become the chief focus of policy (Buchan 2012). The carbon intensity of generation in Germany has not declined over the past decade – since 2003 (IEA, 2011b) – and may well not decline over the coming decade, as nuclear is phased out – some 29 gas-fired plants and 17 coal-fired plants are in the planning and construction pipeline (Platts); and coal use is expected to rise 13.5 per cent in 2012. Similarly, in the UK, support systems have moved in the direction of greater technology specificity (for example in the form of banded ROCs and the new EMR proposals), but emissions from power generation are still in practice a function of overall demand, and the balance between coal and gas generation. By comparison, the renewables technology support has had little impact on emissions. More recently, the current administration has signalled a wish to move away from technology-specific support, though this has yet to be reflected in policy.

The case for there being some role for governments in the process of technology development is probably unarguable – low-carbon technology is needed not so much for immediate commercial reasons but to combat the 'greatest market failure of all time'. Development of many of the options (such as CCS) will be highly risky and too expensive for private firms to undertake without support; and whether technologies such as CCS and most renewables are to be profitable will depend on the market structures and taxes put into place by governments. There is also a need for a longer-term perspective – for instance, as discussed in Part 3, technologies will need to be developed

for the longer-term target, not just to minimize the cost of carbon reductions in the shorter term. So the government needs to set a clear framework in which appropriate technologies can be developed.

Nonetheless, the history of governments in picking technology winners is not always encouraging. Furthermore, it is vital to encourage innovation and competitive pressures for cost reduction, given the prospective scale and cost of the move to a low-carbon system. So there are good arguments for separating technology development objectives from emissions reduction objectives – that is, to enforce the emissions reduction directly, rather than via technology requirements, and to provide technology support, if needed, through separate means, for instance through fiscal support, rather than through market quotas, obligations, or differentiated pricing systems for different technologies.

In principle, this could be done either within a central buyer system as discussed in Part 2 or via an alternative emissions intensity obligation as discussed in Part 3. The central buyer could, for instance, be subject to an emissions intensity obligation and left to achieve it in whatever way was most efficient. The choice between the two approaches may depend on political and ideological preferences. For instance, the advocate of a central approach could argue that this would produce a clear overall strategy and plan, giving certainty for investment over the longer term. The advocate of the decentralized approach could argue that this would be more likely to encourage innovation and would be less vulnerable to the risk of lobbying and policy 'capture' by proponents of particular technologies – a central buyer would be highly politically exposed and could probably not take independent technology decisions given the inevitable sensitivities. But governments will need to keep the options under review as the process of decarbonization continues and, whatever their approach to policy implementation, they should attempt to be clear about their objectives for technology development and how these relate to the ultimate goal of emissions reduction.

Structure of generation – do governments need a strategy on distributed generation?

As discussed in Part 5, the nature of the electricity system is likely to undergo fundamental change as it moves towards decarbonization. This could involve a reversal of historic trends – electricity systems in the twentieth century developed in the

direction of larger scale generation and greater central control, with a central grid ensuring dispatch of plant on a merit order or similar basis. This model has already been adapted somewhat as a result of liberalization – under the UK trading system, plants are generally self-dispatched, but grid operation and balancing remain a central function. The move to a low-carbon system will inevitably add an extra layer of complication, as more dispersed and intermittent sources of generation are introduced. This will, as a minimum, involve a large number of dispersed renewable sources, such as wind farms, whose output is dependent on the available resource rather than the decisions of an operator or central dispatcher. But it may also involve large amounts of distributed generation (dg) – that is generation directly connected to the local distribution system rather than the main national grid. Some of this will be the direct result of policy (such as rooftop solar photovoltaic panels); some may be the product of market and technology development (for instance, if electric vehicles are widely employed, it may be possible to use their batteries as storage devices capable of feeding into the grid as well as drawing from it); some may be the result of the new economic balance or new business models (for instance, microgrids with both demand response and local generation capability).

While the eventual scale of such options remains uncertain, it is arguable that the government needs to have a strategy towards their development:

- First, because some of the forms of dg (like pv) may be promoted as a matter of direct policy.
- Second, because there are, in the views of many, barriers to the effective development of dg within the present system, in terms of pricing and institutional arrangements.[23]
- Third, because of the links with other aspects of the move to decarbonization (like smart grids). If dg is to form a major part of the future system, physical infrastructure, metering, control systems, and so on will need to be designed to facilitate the process.

Whether such a strategy needs to involve central direction is less clear. On the one hand it is arguable that a central planner, such as a single buyer, can take a clear overview of

[23] For instance, the UK Government and Ofgem have conducted a review of the issue (initiated in Ofgem, 2006) and continue to work to ensure that distributed generators are not unfairly treated.

the whole system and choose the lowest-cost options, wherever in the system they may be found. On the other it can be argued that any such planner will prefer options under their direct control and which appear to offer greater certainty, especially when the growth of intermittent generation is complicating the task of system balancing.

Governments will need to consider the way forward; the main considerations might be:

- To identify and remove any barriers to dg – this cannot be wholly a matter for a central buyer or operator in view of the potential conflict of interest.
- To provide some positive support for development of dg through pricing and regulatory systems in order to encourage innovation and gauge the ultimate potential in this area.
- To learn by experience of such developments in the elaboration of an overall strategy for dg, whether as part of a centralized approach or a much more market-oriented system.

Operation of a low-carbon electricity system

As discussed in earlier parts of this study, decarbonization is not just a matter of slotting in new low-carbon plants in place of fossil-fuelled generation. The different types of plant have different characteristics and operating parameters, and this will affect the system as a whole: power system operation reflects the technical characteristics of the plant (and demand) that is available for scheduling and dispatch to meet anticipated load. This applies equally to the means of optimizing the use of the available plant and to the market mechanisms, and to the price bids and the balancing payments/penalties that are inextricably linked to the actual operation of the system. In this context, the most significant technical and economic characteristic of fossil plant is that it offers relatively rapid flexibility in levels of output, while fuel costs have typically been a high proportion of total cost.

For systems dominated by conventional fossil fuel generation capacity, the least-cost choice, for short-term operational decisions, is based primarily on selection of the plant with the lowest fuel costs, up to the quantity needed to meet the load on the system. The characteristics of fossil plant make this a comparatively simple task. The choices are

either prescribed by a system operator who operates a merit order that selects plant in ascending order of cost, or are the outcome of a market process based on individual generators' bids. The price in this wholesale market can be presumed to approximate to the system marginal cost, in other words, the fuel cost associated with the most expensive plant actually generating at a given time. Importantly, prices reflecting marginal fuel costs can provide a high proportion of the revenue needed to reward investment for all the plants operating on the system that rely to some extent on market-based revenues.

The relatively flexible operation of conventional fossil plant means that this process at least approximates[24] to an optimization of plant selection in successive time periods (typically a half hour), where each period is essentially independent of previous and future periods. The price per kWh for a given period can then legitimately be described as the price that induces exactly the right amount of supply, or, with demand-side participation, that instantaneously balances supply and demand, and simultaneously produces the least-cost outcome in choice of plant to generate.

Unfortunately for the future of this model, most low-carbon generation options, especially when taken together with future demand-side developments, have entirely different characteristics, including the following:

- Marginal cost of operation is typically zero (for most renewables) or even negative (for inflexible nuclear plant).
- Output is intermittent, either in a predictable way (solar or tidal), or stochastic (wind).
- Storage, or equivalently demand, which can be controlled or postponed (battery charging), is much more significant in seeking to manage or optimize the generation mix.

[24] This description is a stylized version of the reality. In practice, the whole process of scheduling and dispatch is more complex than this and involves a range of ancillary services wider than just kWh of energy production. Also fossil plant is not wholly flexible and different fossil plant may be more or less flexible, with some plant having significant operating constraints that limit rapid response to changing load or changing supply conditions. Nevertheless, for the purpose of contrasting with the much more dramatic limitations of most low-carbon alternatives, this is a perfectly reasonable approximation which underpins the theoretical basis for a wholesale or 'spot' market design.

- Some generation may be inflexible, or capable of load-following only at relatively high cost (nuclear or plant with an inflexible carbon capture component).

The implications of this are several. First, it is no longer possible to optimize operations on a single period (such as a half hour) basis. Storage and inflexibility considerations in particular imply that optimization of the use of generating capacity will normally need to be conducted over much longer timescales, possibly days or weeks, and in relation to current practice can be described as multi-period, in contrast with single period.

Second, the algorithm necessary for optimization will no longer be an extremely simple merit order ranking, where fuel cost is essentially the only important parameter, and individual MW capacities the main constraints. The cost functions will be more complex and there will be many more complex constraints as to how generators can be ordered to run, or how load can be controlled. Generators, unless protected in other ways by their contracts, are likely to want to place much more complex bids.

It is unlikely that it will be possible to define prices that emerge from an optimal dispatch in the way that current prices emerge as (at least an approximation to) a system marginal cost defined by a simple merit order. Prices for individual periods, if they can be defined at all, will not necessarily be consistent with what plant is actually required to run; nor will they determine what plant runs. A recent conference paper 'Is there still merit in the merit order stack' takes a first step towards considering the issue in terms of modelling divergences in price and plant scheduling outcomes.[25] In theoretical terms, the set of feasible solutions for matching supply and demand is no longer convex. In consequence, no unique 'system marginal price' can be determined, and optimal scheduling and dispatch can no longer be determined from a set of price or cost bids that can ranked in a simple merit order. Prices, if they exist at all, can no longer be relied on to produce the optimal balance between supply and demand. Annex 2 looks in more detail at the principles of wholesale market design in a decarbonized system.

[25] Staffell (2012).

Third, even with relatively modest proportions of low-carbon plant, and continuing with the conventional market model based on a merit order, prices may be zero or even negative for significant periods, with serious implications for the way contracts are structured and investment is financed.

To facilitate flexible and efficient operation, it is likely that the system operator will have to play a larger and explicitly defined role in prescribing what plant runs, moving away from the current UK system of self-dispatch. In principle, this is likely to involve some form of non-linear or integer programming to optimize operations over a number of periods. Reconciling this task with a wholesale market, which was a relatively simple matter in systems based on fossil plant, represents a major issue that policy makers will need to address, regardless of their preference for either more centralized or decentralized systems.

Policy makers will also need to consider the extent to which distributed generation and consumers (in other words 'demand') will be encouraged or allowed to make decisions (when to generate and sell to the system) that require the system operator to adjust accordingly, or whether they will be controlled by the system operator. This is a similar policy choice to the one that characterized the earlier debate over whether generators should be allowed to self-despatch and inform the system operator before the rest of the system was centrally despatched, or run only when, and as much as, the system operator instructed.

Smart grids

The development of smart grids is not necessarily connected with decarbonization, but in practice it will be a major facilitator and the two trends need to be considered together. In this context, a straightforward description of what smart grids are – electricity networks that use digital and other advanced technologies to monitor and manage the transport of electricity from a wide range of generating sources to meet a wide range of end user needs – may be less revealing than a description of what they do:[26]

[26] Adapted from IEA publications, including IEA (2011c).

- Enable informed **participation by customers**;
- Accommodate **generation and storage options**, including distributed resources;
- Facilitate **new products, services, and markets**;
- Provide **power quality differentiated according to different consumers' needs**;
- **Optimize asset utilization** and operating efficiency, reducing losses and congestion;
- Provide **resiliency** to disturbances and unexpected events.

As the discussion in earlier chapters showed, all these functions are going to be essential in the move towards a low-carbon system with multiple, often intermittent, sources and more complex demand patterns, all of which will have to be managed and coordinated efficiently.

There is also little doubt that governments will have to play a major role in the development of smart grids – it cannot simply be left to markets for a number of reasons:

- Grids themselves are part of the **monopoly infrastructure**, and already subject to regulation.
- Decisions about investment in smart grid technology will have a **political and ethical dimension** as discussed in Part 5. Governments will inevitably have to make the underlying judgements.
- **Standardization** of equipment and systems will be needed, in particular to ensure the interoperability that will be at the heart of the new systems.
- **Coordination** will be needed (for instance, with the development of smart meters and with proposals for new market structures) so that the full range of potential can be developed most efficiently – there is no point in having meters capable of two-way communication if the grid itself cannot support this function.
- **Path dependence**. For similar reasons, a strategic approach to smart grid development will be needed to ensure that important future options for the operation of a low-carbon system are not precluded.

Thus, even governments that see their primary function as enabling rather than controlling will have to take a close interest and central strategic role in smart grid development.

However the main message of the earlier sections is that much research is still needed (for instance into such key issues as consumer acceptance) before the way forward in this area will be clear – indeed the IEA smart grids technology roadmap (IEA, 2011c) suggests that many of the main elements of a smart grid policy cannot be put in place before around 2020. The task for governments is therefore three-fold:

- To undertake or promote the necessary research and development activities to inform the main strategic policy choices.
- To engage with consumers, stakeholders, and others to develop a consensus on the way forward.
- To move forward as quickly as possible (provided this can be done without precluding potentially valuable options for the future) with the development of smart grid and associated technologies.

Interconnectors

Smart grids are generally seen in the context of individual electricity systems and fall within a national policy framework. However, transmission development at international level has the potential to be of comparable significance. Traditionally, interconnections between different electricity systems, such as the different countries in Europe, were seen primarily in terms of security – in an emergency, they enable a system short of power to import from a neighbour. There was also an efficiency advantage – in a larger system, the level of reserve margin needed is lower, especially where an n–1 criterion is used (in other words, that the system should be able to withstand the sudden loss of its largest component). More recently, with the advent of liberalization, the benefits of interconnections have also been seen in their ability to encourage trade and the development of the single market, with associated gains in efficiency and greater competitive pressures.

As systems move towards decarbonization, interconnections will have a major new role in promoting the transition:

- They should allow greater efficiencies as countries concentrate on the exploitation of the cheapest resources available (for instance, solar power in southern Europe; wind power in north-west Europe), which can then be made available more widely through trade.
- They should help the effective development of resources straddling national borders – for instance the large wind resource in the North Sea for which the North Seas Countries Offshore Grid Initiative (NSCOGI) aims to connect ten countries with a huge network of wind farms and interconnectors.
- They would help provide a larger pool in which to integrate variable resources such as wind, so reducing the impact on system costs (as happens at present, for instance, with Danish wind exports to Germany and could happen in future with Ireland's wind capacity).
- They should also help balance out fluctuations in supply from such variable sources – the larger the area covered, the more stable the level of supply is likely to be.
- They may enable the exploitation of resources that would otherwise be unavailable, such as the Desertec project in North Africa.

Interconnections in Europe are generally recognized to be underdeveloped, partly because of the history set out above, partly because of political and regulatory issues that may be acting as barriers to their construction (Jacottet, 2012).

Unlike many of the other issues discussed in this section, it may be that in this particular area a more market-oriented government would actually like to see a more centralized approach across Europe. This could contribute to the development of a more harmonized single market and to the more effective and coordinated pan-European development of renewable resources. There are of course wider difficulties in the way of a pan-European approach (discussed below); even in the specific area of interconnections, progress in this direction may have to be evolutionary. The ultimate goal, consistent with a single European market, might arguably be a European agency on the lines of the Federal Energy Regulatory Commission (FERC) in the USA, which would oversee inter country power trade and the construction of interconnectors, and ensure that a harmonized set of rules was applied. But governments might well first want to consider interim steps, such as the development of more interconnection across

the EU; harmonization of regulatory approaches to ensure that interconnectors are considered in a consistent manner by both or all the regulatory agencies involved and that national transmission schemes do not receive unjustified priority; and removing various barriers in areas such as environmental approvals and financing which have in the past slowed down the development of interconnectors.[27]

The role of the demand side of the market

A key message from earlier parts of this study is that decarbonization is not just a matter of technology but also of people and their behaviour and interactions with the electricity system; not just smart grids but smart customers.

Policy makers have good reasons to want to encourage customer participation in electricity markets. Some of the uncertainties and challenges relating to such participation are discussed in more detail in Part 5. Meanwhile, there are a number of specific policies that would contribute to this effort which policy makers should consider:

- Designing capacity markets and reserve markets that facilitate demand participation.
- Getting rid of regulatory barriers to demand participation in energy markets, for instance by providing system operators with incentives to consider demand response on an equal basis to supply alternatives.
- Ensuring that smart grid and smart metering allows competing companies to offer a range of customer participation services, avoiding any lock-in to particular retail companies or software.
- Providing economically efficient regulatory incentives for customers to combine demand response and distributed generation – for instance through net metering that reflects the customer's full economic contribution to the system in the form of hourly net generation and demand response.

Policy makers also face challenges in developing the infrastructure that will allow customers to participate accordingly, as discussed in the section on the smart grid – the

[27] This process of integration is already underway, with both gas and electricity 'target' models having been developed for cross-border trade. This process is being managed through the European Agency for Energy Regulation (ACER).

key message is that coordination between the different elements is needed for the full potential of the demand side to be realized.

Competition

What will competition look like in a low-carbon electricity sector?

The discussion above suggests that governments may have to take a more active role in the development of electricity systems than they do at present if they wish to promote an active process of decarbonization. This goes against the trend of recent decades in the direction of liberalization and greater competition within the UK and across the EU – indeed it may be questioned whether a radical commitment to decarbonization is compatible with a commitment to liberalization. Certainly, at the moment in the UK, the two appear to be in conflict; the government is taking over many of the central planning and investment functions which, in a liberalized system, would be left for individual market participants. This study has suggested that there are alternative approaches to the investment question which would leave much more of a role for markets. But there is still a question of whether those markets can be genuinely competitive when the trend across Europe appears to have been towards a sort of 'non-competitive oligopoly' dominated by a small number of large vertically integrated utilities; the move to decarbonization may further accentuate this trend.

Indeed, it may appear that oligopoly is the inevitable future of the sector since this is the structure that predominates in most developed countries. To the extent that market power is one of the ways that cost recovery can be assured, regulated oligopolies have their attraction for policy makers: in return for allowing oligopolists to earn a reasonable return, they will undertake the investments that the government would like to see. That is certainly how the game has been played in a number of countries. If government chooses to support very heavily capital-intensive low-carbon generation (such as nuclear or CCS-coal), then this will favour a continuation of the oligopoly model since there are very few companies with the financial and technical capacity to deliver.

On the other hand, government need not choose that path. Arguably, it is not desirable to rely overly on the traditional utilities to deliver the decarbonized electricity sector.

The development and deployment of new low-carbon technologies, and the promotion of efficiency, demand response, distributed generation, and conservation by consumers are not areas where traditional utilities have shown any special comparative advantage (although a regulated utility might have an advantage if its cost of capital were lower as a result of regulatory guarantees). In any event, the latest evidence in the UK suggests that the investment requirements for decarbonization are well beyond the capability of the Big Six companies, so to rely too heavily on the latter would put the decarbonization agenda in doubt.

Furthermore, the industry in the UK and elsewhere does not rely solely on vertically integrated oligopoly to deliver the required investments. There are merchant plants in the conventional power business, and decentralization should become increasingly easy as the industry shifts to the lower capital cost plants needed to provide backup energy. For instance, with the planned closure of its nuclear plants, Germany plans to rely very heavily on wind power, but the low reliability of wind at times of system peak will require an increase in the number of flexible conventional plants (open cycle gas turbines in particular). Meanwhile, in the growing renewable energy business, there are new companies (from around the world) that specialize in developing and running renewable power stations, and no reason to assume that the traditional utilities will be the renewable generators of the future, particularly if the new generators can sell on long-term contracts to a single purchasing agency. There are also new developers of distributed generation, demand aggregation, and demand response services that will compete with the oligopolies.

Retail competition

As the discussion above suggests, policy makers are increasingly faced with the challenge of relying on the ability of the oligopolies to provide supply security, in return for a reasonable return, while promoting the development of technologies and companies that directly challenge the profitability of the traditional oligopolies. In relation to decarbonization investment, this challenge focuses on the upstream generation side of the industry, but governments will also need to consider the implications for downstream competition.

The original concept of retail competition is that it gave customers the choice between retail suppliers of a simple electricity service. In principle, the goal was that customer choice would lead to improved quality of service, more competitive (lower) prices and margins, and new service offerings (such as green electricity). While this has occurred to some extent, the benefits are much debated. Critics in the UK argue that retail competition has not generated much if any benefit for customers, and that it has led to unacceptable distributional effects (for example, customers who don't shop are subsidizing those that do). Supporters of retail competition in the UK point to the benefits for those who have been active shoppers, and even for those who have not. Whatever the conclusion, it is important to note that the retail activity has traditionally accounted for less than 5 per cent of the total value added in electricity, and so there was a limit to how much of a saving could be achieved through retail competition on its own.

The new frontier for retail competition is the active participation of customers in the markets for energy, capacity (reliability), and ancillary services through the customer participation that was described above. The reason that this is more important than the traditional form of retail competition is that customer participation in these new markets has the potential to add significant value to the system by reducing overall system investment and operating costs.

The policy issues here are two-fold. On the one hand, the regulatory framework could encourage customer participation more or less aggressively. Although traditional forms of retail competition may not generate much value, competition for retail customers is a natural way for new service providers to capture and aggregate clients – offering to supply their electricity at the same time as offering new demand-related services that will lower the bills. If policy decisions discourage customer choice among retail suppliers (for example, by providing tariffs of last resort or by offering all customers the same tariff), then there is a risk that they will diminish the prospect of new demand-related services being developed by retail suppliers and energy service providers.

On the other hand, it is important that real-time price signals reflect the costs on the system and that customers and their suppliers have the potential and incentive to respond to those signals, thereby lowering the costs of the system as a whole. It is

possible that these signals can reach customers through both the decentralized and centralized models that have been described above. In any case, policy makers should ensure that these price signals do reach customers.

Regulation and institutional arrangements

One of the primary questions addressed in this study is how far the imperative of decarbonization leads to a shift in emphasis away from markets in the direction of central control. But whatever the new market arrangements, it is apparent that there are major implications for regulatory and other institutional arrangements.

UK developments

Indeed, these implications have already been felt in relation to the UK regulator Ofgem. Originally its duties focused exclusively on economic regulation – the promotion of competition and consumer protection. There was a clear demarcation – the government was responsible for energy policy; the regulator for the operation of markets. This distinction can no longer be drawn.

It started to become blurred in the early 2000s. The regulator's duties were amended to include the promotion of sustainable development and a requirement to have regard to the effect on the environment in carrying out its functions. Under the Utilities Act 2000 it was also required to have regard to social and environmental guidance issued by the government. By the late 2000s 'E-Serve' (which implements the environmental aspects of the regulator's functions) constituted the bulk of Ofgem's spending. Following the recent Ofgem review, the government now proposes to issue a 'Strategy and Policy Statement' setting out its policy goals; Ofgem will be expected to set out annually how it plans to deliver its contribution to each policy outcome. In other words the job of the regulator is now as much to help deliver the government's policy goals, as to police markets.

Against the background of the need to move towards decarbonization, one option may simply be to accept this trend. The future task of the regulator would then be to act as a partner in the process, in particular promoting efficient outcomes in areas such as distributed generation, demand response, interconnections, development of smart grids,

and so on. For the reasons given under these headings, a degree of government involvement will be needed in these areas, and the regulator will be one vehicle through which the government promotes its strategies.

An alternative strategy might be to narrow the task of the regulator once more to its core economic and market oversight functions. This might well, in turn, necessitate the creation of new institutions to provide support for the process of policy implementation itself, perhaps in the form of an arms' length Energy Agency. In doing so, there is clearly a risk of creating tensions between the different parts of the system, but this could be regarded as positively beneficial – arguably, one problem with current decarbonization policies is that they are not subject to a sufficient degree of independent expert scrutiny. On a central buyer approach, the role of Energy Agency could possibly be combined with that of central buyer; on a more market based approach, it could give advice directly to government on issues of policy implementation – as opposed to the broader questions of strategy development with which, in the UK system, the Climate Change Committee is concerned. That body is generally regarded as having performed a useful role and it would not be sensible to change its functions radically.

More contentious is the question of investment. If the EMR approach is adopted it will involve major institutional, perhaps almost constitutional, changes in governance of the energy sector in the UK. The government has made it clear that it will be in the lead on such matters as deciding what new capacity is needed under the FiT and capacity mechanisms; what the main features of the relevant contracts should be; and what prices should be set. This represents an unprecedented degree of direct planning of the electricity system by the government (much more interventionist than the pre-liberalization indirect arrangement whereby the government approved an investment programme developed by the CEGB); furthermore, the implementing agency, the National Grid, is now a private company rather than the nationalized industry it was in pre-liberalization days.

This is a major new step in UK traditions and practices of governance, and raises questions about, for instance, the expertise available to DECC, where responsibility will lie for any operational and security problems, and how market signals will flow from customers to the ultimate decision makers. It is partly a wish to avoid this sort of

problem which leads to the more market-oriented approaches, such as an intensity target; or to more clearly defined allocations of responsibility, as under the single-buyer approach. But if the EMR approach is continued, the implication is that a wholesale transformation and reinvention of institutional structures will be needed. It may be that, as discussed above, a new body is needed with a focus on policy implementation rather than on targets and strategy.

Countries outside the UK

The above discussion on institutions and regulation relates to the UK and is not necessarily a useful guide for other countries. Each country will choose its own route to decarbonization and will need to consider the regulatory and institutional implications at an early stage. Countries that share a high level of interconnection, for instance, are more likely to seek cross-border institutional arrangements to provide a degree of coordination. For instance, in northern Europe, coordination through Nordpool will probably play an increasingly important role, as will the institutions in the Iberian peninsula (MIBEL).

However, in all countries there is likely to be a need to consider network regulation. Decarbonization changes the role that networks will play and this is very likely to change the nature of the regulation of these networks. Networks will need not only to be extended to connect more isolated generation sites (such as offshore wind), but also to support new forms of distributed generation, two-way trade with customers, and an expanding electric vehicle fleet. Whereas previous regulatory regimes compensated network investors for their investment and operating costs, new regulation will need to provide incentives for a greater degree of innovation.

This change in requirements has led the UK to adopt a new form of regulation called RIIO (Revenue = Incentives + Innovation + Outputs), whose primary aim is to reward companies on the basis of their ability to deliver outputs (for example, connected power stations), rather than on their ability to minimize the costs of their inputs. In this way, RIIO is supposed to provide incentives for transmission and distribution companies to be innovative in their thinking about how to deliver the decarbonization agenda.

This is a very new initiative and it is not yet clear how well it will work. Government or regulators still need to define what 'outputs' will be measured and rewarded. This could quite easily lead to government-defined investment agenda, rather than innovation. Nevertheless, it is clear that government will need to rethink the way that they regulate networks, with a view to providing the sorts of incentives that are now required to deliver decarbonization.

The European dimension

While most of the discussion in this study, reflecting the current situation on the ground, has focused on national strategies and national electricity systems, there are many strong arguments for approaching decarbonization on a European basis. The EU has a collective carbon target and commitment to burden-sharing; a Europe-wide approach should be cheaper and more efficient than separate national approaches to meeting carbon or renewables targets; and it is logical for the forthcoming single market in electricity to operate under a single set of rules. Differences of approach can create tensions and distortions in a range of areas, for instance:

- Different support regimes for renewables can lead to unbalanced development – as for instance with the rapid growth of solar power in Germany, which is far from the sunniest country in Europe.
- Similarly with carbon taxes – the proposed UK minimum carbon price will make it more attractive to export French nuclear power to the UK than to other markets, while at the same time undermining the ETS price across Europe.
- There are often externalities in interconnected systems arising from national policies – the phase out of German nuclear and the consequent need for the transmission of large amounts of wind power from north to south Germany has led to significant 'loop flows' in neighbouring systems.
- Such differences can create disincentives to trade. For instance, as Germany phases out its nuclear plants while neighbouring countries retain theirs, pressure may grow to restrict imports; at the same time, exporting countries may fear the impact of price rises as trade increases (as has already happened in France) and themselves resist its expansion, undermining the single market.

- Electricity market reforms to promote decarbonization may themselves distort potential trade. Capacity payments, for instance, normally require a generator to commit supply to a specific market.

In fact, it is difficult to see how a true single market can be developed while countries are taking different approaches to decarbonization. Equally, however, it is clear that there is no prospect of a wholesale shift to a European approach. Energy policy, and specifically the make-up of the national fuel mix, is a matter reserved for member states and (as the contrast between French and German approaches to nuclear illustrates) they face hugely different political climates and sensitivities.

Nonetheless some cautious moves towards a more European perspective would almost certainly pay dividends. These could include a reinforcement of trends already under way – for instance, further encouragement of 'market coupling' to promote trade and price transmission between member states; measures to harmonize the approach to interconnections; and a buttressing of the ETS to ensure it gives clearer and stronger price signals. In the medium term, such measures could be supplemented by a degree of harmonization in the form (and eventually level) of renewables and other low-carbon support mechanisms; development of a more consistent approach to electricity market structures; and creation of a Europe-wide regulatory capability. As with interconnections, the choices here probably depend more on attitudes to European integration than on views about markets versus centralization.

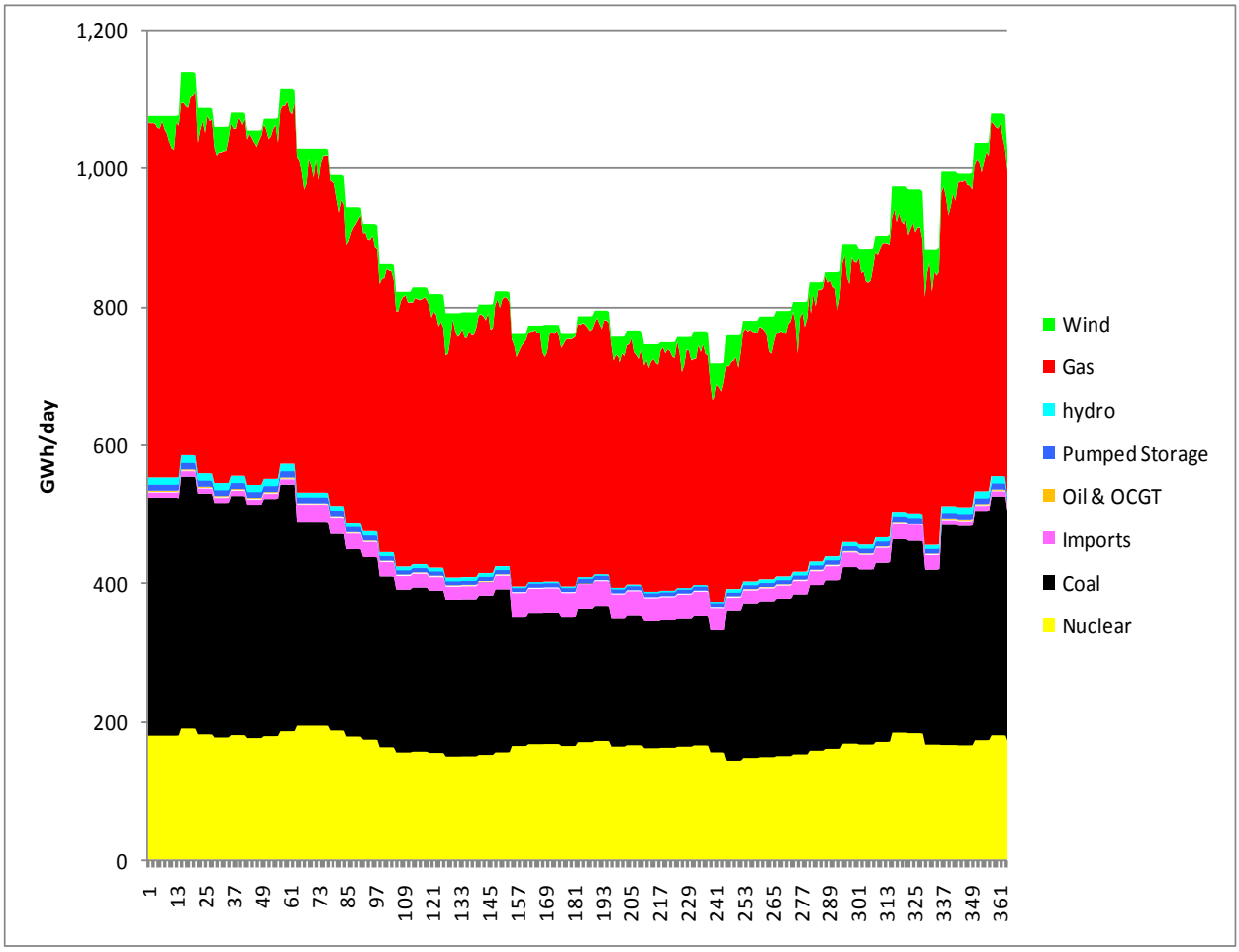
Conclusions

Our main conclusion is that the road to decarbonization will present governments with big choices. The most immediate challenge is how to give incentives for the necessary investment in low-carbon generation and the associated transmission requirements. The UK has chosen the route of Electricity Market Reform based on long-term contracts determined by the government; this study has sought to look at the drawbacks of this approach and demonstrate that there are alternatives. But providing incentives for investment is only one part of the picture. On many other issues, including the five main areas discussed above, there will be important decisions for governments on how far, and in what direction, they want to drive the decarbonization agenda. In these areas too,

alternative approaches are possible, depending on a country's circumstances and policy preferences. But the key message for governments is that they need to consider all these issues in an integrated fashion – it is not just a matter of changing one set of upstream technologies for another; the implications extend across the entire electricity sector, including its consumers. They will therefore affect everyone in the countries concerned, whether or not they realize it at present, and the sooner governments give sustained attention to all the interlinked issues the more likely it is that there will be a coherent and integrated outcome.

Annex 1 Changes in UK pattern of generation with decarbonization

Chart 1:[28] UK sources of power generation 2009 – daily (3.8GW wind capacity)



[28] Charts drawn from OIES paper NG54 *The Impact of Import Dependency and Wind Generation on UK Gas Demand and Security of Supply to 2025* Howard Rogers August 2011.

Chart 2: UK sources of power generation 2025 – daily (43.2 GW wind capacity)

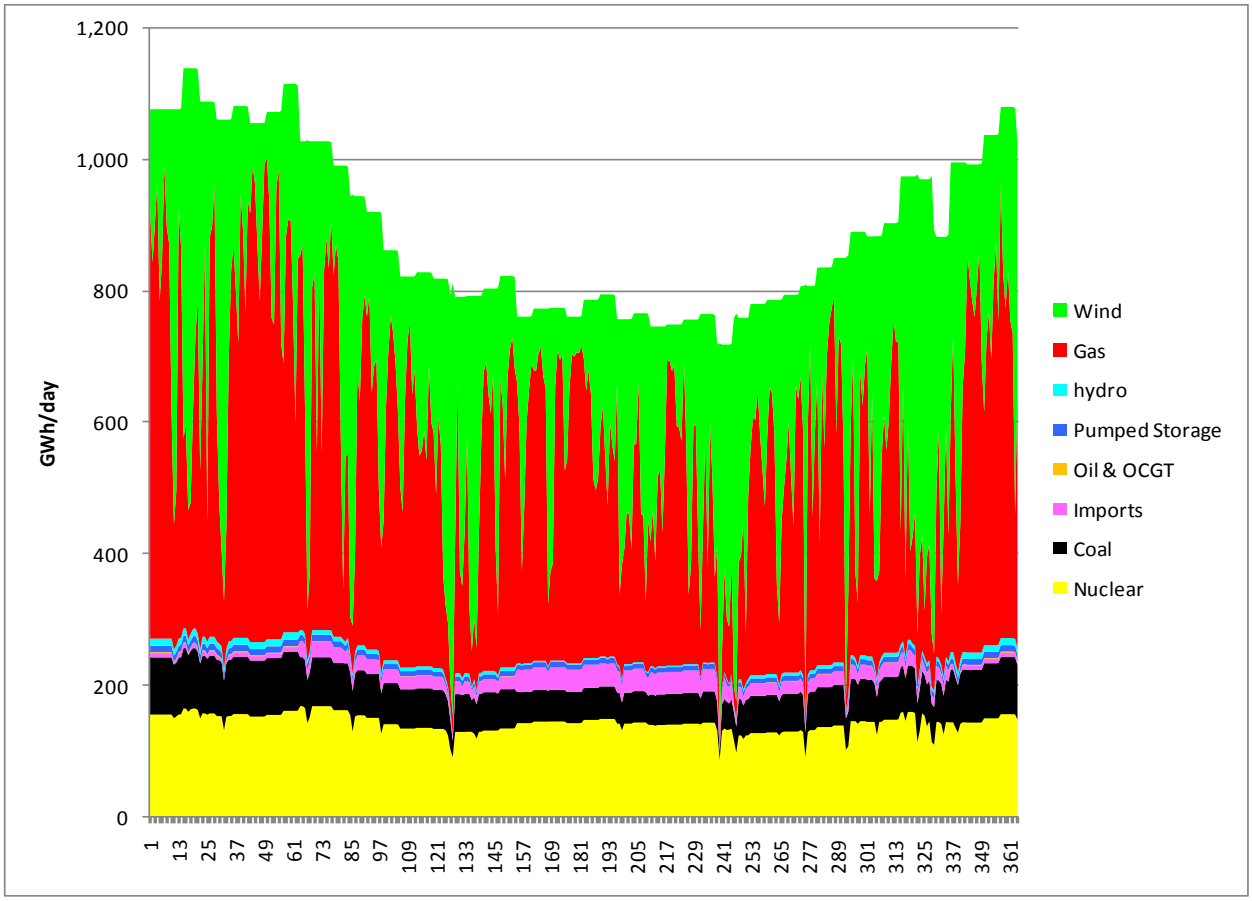
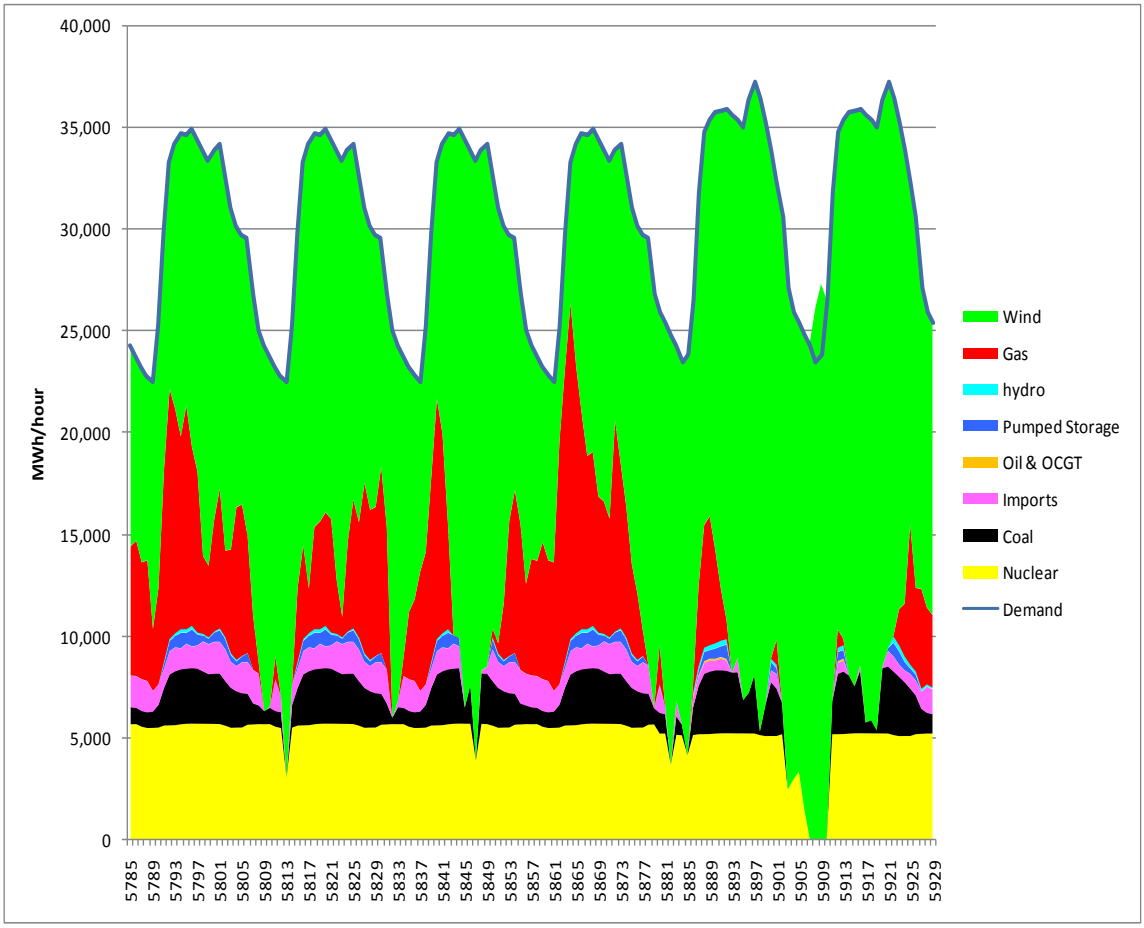


Chart 3: 2025 hourly analysis days 121–127



Annex 2: Design of Wholesale Markets and Pricing

The changes in system operation discussed in the main text will transform the nature of the wholesale market. Both its organization and pricing structures will need to reflect these changes.

As far as market organization is concerned, there are two alternative approaches. The first is to continue with current practices and assume that, notwithstanding the theoretical objections to forcing a merit order and fossil fuel based approach on to a low-carbon system, nevertheless some approximation to an efficient dispatch can be achieved through the conventional approaches of self-dispatch and imbalance pricing that operate currently. This is certainly an approach that will work while the proportion of low-carbon plant remains small. It could also, it may be argued, be subject to technical fixes if problems start to manifest themselves as inconsistencies and obvious inefficiencies. This might be expected to result in a larger number of 'special arrangements' and definition of more and more additional 'ancillary services'. The danger in this approach is that it will simply fail, and the market will become increasingly artificial and dysfunctional, undermining the returns to the generation investments that have been made.

An alternative but similar approach is to analyse the problem in more depth in order to provide a more robust replacement for the wholesale market, but one explicitly based on much more complex bidding and optimization processes that will reflect the particular characteristics of the future plant connected to the system – which will differ from one country to another, but will increasingly be plant with high fixed costs and low marginal costs. The hope then would be that a conceptually and practically robust alternative system of bidding and scheduling/dispatch could be developed. In order to meet the functions currently performed by the wholesale market, it would need to satisfy, within a low-carbon power sector, the requirements of technical stability and economic efficiency (in other words, the least cost selection of generation and demand-side options). Most importantly it would need to deliver individual, period-by-period, prices

that do indeed fulfil the normal function of prices in a well-functioning market, balancing supply and demand and providing the right signals for investment. There is however no guarantee that this can be achieved, or even that this is a plausible aspiration.[29]

The second approach, in the context of a relatively decentralized system such as that in Great Britain, is to require transfer of a higher degree of responsibility for the efficient and secure operation of the system to the National Grid. Plant would no longer be able to self-dispatch, and single period bids, as in the old Pool, would no longer be feasible for the reasons given above. Distributed generation might also be given less freedom to self-despatch and sell to the system, and demand response would likewise be controlled. The Grid would instead take on the responsibility for dispatching plant efficiently, taking into account the more complex and less flexible characteristics of that low-carbon plant working to contractual commitments. This proposal reinstates the system operator as a central controller. The system operator would then have the duty of ensuring secure and efficient system operations and would be able to instruct or control individual plant, or certain types of consumer load, in accordance with their technical capabilities and their contractual commitments.

This second approach raises a different set of questions, mainly about the nature of the relevant generation contracts, such as who would be the counterparty (if not the Grid) and how generator performance would be incentivized within the contracts. It would also raise questions about whether it was acceptable to limit the freedom of generators and customers to act independently of instructions from the system operator.

As regards the bidding processes themselves and the way in which prices are derived, we can consider two possibilities in line with the above analysis. The first is that a satisfactory alternative wholesale market algorithm, more complex than a simple half-hourly or hourly merit order, can be developed to deal with the optimization of low-carbon plant. The algorithm should be able to produce efficient least-cost system operations, but crucially it should also operate by taking bids from generators and

[29] The technical reason that this may be an impossible task is that the set of feasible options is no longer convex. A simple linear programming optimization (merit order) has been replaced by a possibly non-linear one. Additional but connected problems are the multi-period nature of the optimization and the possibility of zero or (theoretically) negative prices.

demand-side participants, on a multi-period basis, and with significant conditionalities that reflect the technical characteristics of their plant, including inflexibilities, high costs of load following, and storage options. Equally, one of its outputs should be a set of prices that can be shown to provide efficient signals to the plant operators.

If this is indeed a viable option, we should nevertheless expect to see much more complex bidding processes, possibly even multi-stage auctions with several bidding rounds to reach an efficient outcome, and a much more complex definition of what the relevant prices are.

An alternative approach may be required if the above process either becomes too cumbersome or proves impossible to achieve. In that case, the system may revert to one where both scheduling and dispatch, and the generation of price schedules, are de facto under the control of the system operator. Generators however would be paid according to the terms of their contract, and prices would play a role primarily in relation to the recovery of costs from downstream suppliers and consumers. This question then links to the broader issues of how a central purchaser would function, and to the nature of the generation contracts.

Defining the point at which changeover to a new system might be required is largely an empirical question. One of the criteria for making the judgement might be the proportion of time when non-fossil plant is at the margin. Another possible option would be to wait until the current system became clearly dysfunctional. However, these developments may need to be anticipated in contracts, which argues for earlier rather than later consideration of the issues.

We should recall that the switch from the Pool to NETA, by removing the 'Pool price', created a similar burden of contract renegotiation, but that element of the change was managed without too much difficulty.

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