CHAPTER 6

EUROPEAN ELECTRICITY MARKETS: REFORM OR REVOLUTION?

Introduction

Many of the issues analysed in this book arise from the tensions between two of the Energy Union's main goals: a freely operating single market and a secure low-carbon energy system. This chapter seeks to develop the implications of this underlying dilemma. It looks at one particular arena where the tensions are playing out in an acute form—the electricity sector.

Electricity is the main focus of the present chapter for two main reasons:

- First, as discussed below, electricity is likely to be the first sector to decarbonize and is currently the main focus of policy intervention for climate change reasons.
- Second, because of its systemic nature, electricity responds in complex ways to interventions. The problem is compounded by the forms of intervention adopted by EU governments, and in particular support for renewables, as discussed in Chapter 5. Renewables are central to the issue because they constitute one of the three targets in the 2020 and 2030 goals. The renewables target differs from the other two in being defined in terms of a specific set of technologies rather than energy or emissions; it leads to interventions designed to favour particular forms of electricity generation. The risk that interventions in favour of particular technologies could undermine the single market was addressed in Chapter 5. This chapter looks at another risk—that the interventions will render wholesale electricity market price signals ineffective and thus undermine the basis of liberalization in electricity.

The Commission has recognized at least part of the problem. It is proposing changes to electricity market design intended to

accommodate renewable sources (and demand response) more effectively. However, these proposals are unlikely to resolve the underlying problems, and this chapter concludes that unless a new policy approach is developed, the tensions are only likely to increase as the EU seeks to complete its internal market and at the same time meet its ambitious climate goal of an 80–95 per cent emissions reduction by 2050.

Electricity in the firing line

Electricity is the main sector in the firing line in relation to decarbonization (it is the strongest candidate for making significant early emissions reductions and therefore the main focus of policy attention) for many reasons. The main one is the simple fact that there are many technically viable options for producing low- or zero-carbon electricity, including nuclear power and many renewable sources. By comparison, the practical options in other sectors, like transport, are at present more limited.

Furthermore, the technologies used for power generation have a very significant impact on national emissions totals. As **Table 6.1** indicates, the difference in carbon emissions per capita in typical northern European countries (which are likely to have broadly similar heating loads) is driven primarily by the difference between their electricity-related emissions. There is little difference in transport-related emissions and they have little effect on the relative totals (indeed Sweden, the country with the lowest overall per capita emissions, has the highest transport emissions—and the coldest weather).

Furthermore, the technical and logistical task of introducing low-carbon technology into electricity generation is relatively simple. Only a small number of installations is involved. In the UK until recently, about 30 large plants, mainly power stations, accounted for about 30 per cent of emissions—about the same as total transport emissions or emissions from residential buildings.[1] Replacing those power plants with zero-emissions

1 Author's calculations. The power station figure has dropped a little in nominal terms as the largest power station, Drax, has switched to biofuels (though of course it still emits comparable quantities of CO_2).

Table 6.1: Emissions by sector in selected northern European countries 2012 (tCO_2/head)

Country	*Total*	*Electricity and heat*	*Transport*	*Residential*	*Industry*
Denmark	6.64	2.6	2.0	0.5	0.7
France	5.1	0.7	1.9	0.8	0.9
Germany	9.2	4.1	1.8	1.1	1.4
Netherlands	10.4	3.2	1.9	1.1	2.4
Sweden	4.3	0.3	2.1	0.0	0.9
UK	7.2	2.8	1.8	1.1	0.7

Note: The figures in the middle column of this table refer to CO_2 emissions from electricity and heat generation—i.e. they include district heating schemes, many of which are based on combined heat and power (CHP), though not individual residential heating—this is the form in which the data are available from the IEA. For those countries with a high proportion of CHP, like Denmark, the figures in the middle column are therefore not directly comparable with those from countries with little district heating, like the UK. However, adding the electricity and heat emissions to those for residential heating gives a somewhat more representative figure, which is why the latter figures have been included. Total emissions include those from other sectors (commercial, agricultural, and others).

Source: IEA 2014a

capacity is simpler in both principle and practice than replacing the 30 million vehicles in the transport fleet or upgrading 26 million homes.

There are also clear examples of rapidly falling national CO_2 emissions as a result of an electricity investment programme. For instance, as shown in the **Box**, UK emissions fell significantly during the 1990s as a result of the rapid investment in gas-fired combined-cycle gas turbine (CCGT) plants. Other countries, like Sweden and France, have seen even more notable reductions, in these cases as a result of investment in nuclear. The reductions were of the order of magnitude required for an effective response to climate change, and they have proved broadly sustainable, as the data in Table 6.1 indicates. The empirical record shows no comparable examples of rapid emissions reductions apart from those due to industrial collapse (e.g. after the fall of Communism) or war.

Rapid falls in emissions due to changes in electricity generation

- **United Kingdom, 1990–95**. Emissions from energy supply fell by 36 $mtCO_2$ (6 per cent of the UK total), mainly because of the shift from coal to gas in power generation following the rapid development of combined-cycle gas turbine (CCGT) technology. Gas-fired plant capacity rose from virtually nil in 1990 to 9 GW in 1995 (and 19 GW in 2000); gas generation rose from 5 to 64 TWh, while coal output fell by around 50 TWh. Nuclear output also increased over the period, by about 20 TWh. By comparison, the renewables contribution (1 TWh extra over the period) was insignificant.
- **France, 1980–90**. CO_2 emissions fell by over 100 mtCO2 (around 25 per cent of France's total emissions), mainly because of the rapid development of nuclear power. Nuclear generation rose from 61 TWh in 1980 to 314 TWh in 1990, as nuclear capacity grew from 14 GW to 55 GW over the period. Electricity output as a whole also grew significantly over the decade (from 257 to 417 TWh), but the growth in nuclear enabled a huge reduction in coal and oil use—even renewables production fell over the period.
- **Sweden, 1980–90**. CO_2 emissions fell by around 21 $mtCO_2$ (nearly 30 per cent of Sweden's total), mainly because of the development of nuclear power and the substitution of electricity for oil in home heating. The period was in the middle of a major investment programme in nuclear generation following the oil crises of the 1970s. From 1974–90 Swedish electricity output virtually doubled (it grew from 75 to 146 TWh), but during that time the composition of supply also changed fundamentally. In 1974, there was only a minimal contribution from nuclear; by 1990, nearly half of Sweden's power came from nuclear, with most of the rest being hydro. Nuclear capacity grew from 1 to 10 GW; hydro from 12 to 15 GW.

Source: IEA 2014a

Not only is the technical and logistical task of reducing emissions in electricity generation easier than in other sectors, but the political problems are also usually more manageable. For instance, there is little direct impact on consumers' lives, as electricity appliances do not need to be changed. Furthermore, since electricity has low price elasticity, even if prices rise as a result of the measures, there should be less risk of wider economic distortions. (In effect, the climate measures would amount to a sort of 'Ramsey' tax—that is, a tax on goods for which demand does not change very much with price. Many economists regard this sort of tax as desirable in the sense that it does not significantly affect consumer behaviour, so is less likely to distort economic decisions.)

The emissions reduction potential is of course something which arises on the supply side; electricity does not create emissions at the point of consumption. But as well as being emissions free, electricity is also uniquely flexible and controllable as an energy source—it can be substituted for almost any other form of energy in use (whereas other energy sources cannot be used for most appliances and information technology applications). In the past, electricity's main handicaps have been that it is difficult to store in a convenient fashion or make it effectively portable for use in vehicles. Technology is reducing these handicaps and policy is encouraging the use of electricity more widely—given that electricity is being decarbonized anyway, it offers probably the best opportunity for decarbonizing sectors like transport, which are at present dominated by hydrocarbon fuels.

The outcome of all these factors is that, in outline terms, many countries' decarbonization strategies are based on the same overall sequence: first, decarbonize electricity, then electrify other sectors of the economy (e.g. via the use of electricity in transport and residential heating). In the UK, for instance, the UK's Committee on Climate Change (CCC) saw little alternative to starting with the decarbonization of electricity. It concluded that 'any path to an 80 per cent reduction by 2050 requires that electricity generation is almost totally decarbonised by 2030' (CCC 2008: 173). This standpoint has been at the heart of the government's strategy.

Similarly, the European Commission's 'Roadmap' sets out a plan to meet the long-term target of reducing domestic emissions by 80 to 95 per cent by mid-century. The strategy in the 'Roadmap' is broadly similar to that adopted in the UK. 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…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. (COM 2011: 6)

In other words, the electricity sector is going to be the one most affected, and affected at the earliest stage, by interventions to effect the low-carbon transition which the Energy Union is aiming at. The impact of these interventions over time will be to change the whole structure of the industry. They will affect the whole system, including the demand side (discussed in Chapter 7); this chapter focuses on the consequences for electricity wholesale market design.

European electricity markets

At the moment, the bulk of the interventions in electricity involve technology-specific support, as discussed in Chapter 5. In addition, support is also being offered by different countries, and in different ways, for reliable capacity (see Chapter 4). As Europe progresses in its energy transition and the degree of intervention grows, the differences of approach across the continent are only likely to become greater. If the end result is that 28 different member states are operating 28 different national support schemes in different ways and for different supply sources, mostly confined to domestic production, there will not be a genuinely level playing field across Europe. An increasing number of plants will be remunerated not, or not just, by revenue from electricity markets but by income from the various different schemes for rewarding capacity or investment in low-carbon sources. Producers in different countries will be responding to different price signals and facing different incentives. The risk is that as long as the various separate national government schemes continue to be the driving force for investment and operation, the European wholesale electricity market will increasingly turn into a residual mechanism for dealing with the power thus generated.

However, the problems go wider than the absence of a level playing field and barriers to trade arising from member states' different energy policies. An even more fundamental difficulty lies in the nature of traditional electricity market structures, as exemplified in the so-called 'Target Model'—the standard form for trading in electricity across Europe. As explained in Chapter 4, the model is built around the coupling of separate electricity markets via day-ahead markets, and eventually the entire trading timeframe, for buying and selling electricity by the kWh (or MWh).

The choice of kWh (or MWh) as the unit for trading (i.e. the 'energy-only' market) might at first sight seem natural. It might appear that such markets are 'transparent windows', simply the medium through which trading takes place and not linked with any particular technological structure—that kWh pricing is as natural to electricity as pricing by the barrel is to oil, for example. Certainly, this seemed to be the original assumption in the moves towards a single European market—that a European reference price for a kWh of electricity would emerge in the same way as an oil reference price of so many dollars per barrel. But in fact, pricing structures depend on technologies and customer preferences and can change over time—we do not, for instance, expect that internet use must always be priced per gigabyte, or that telephone calls must always be charged for by the minute, as used to be the case in many countries. We understand, and generally benefit from, the range of packages available, with various trade-offs between unit costs and subscription charges.

Electricity pricing has hitherto been less varied. It has been affected by government regulation, long-standing practice, and the characteristics of the technologies in place. KWh (energy or unit) pricing has long been the standard approach to trading electricity, though other cost drivers, like maximum demand (kW, which reflects the level of demand, or the rate of energy use, at any particular moment, and hence the amount of capacity

needed to supply it) are taken into account for some consumption classes. The marginal-cost approach to pricing is based on the technologies common in the 20th century industry, and in particular on the economics of fossil plants, in which the costs of the marginal generator could be taken as representing total system costs at any particular time.

The move to a low-carbon system will lead to a fundamental change in technologies—principally in the move to renewables and distributed generation (like solar photovoltaics [PV]). These technologies are being installed very widely across Europe. Some countries may also opt for other low-carbon sources, like nuclear power and carbon capture and storage (CCS). The overall effect will be to change the economic and operating characteristics of the industry in a fundamental way:

- **Intermittency**. A large proportion of the new sources will be intermittent or non-dispatchable—in other words, they will not operate flexibly, either at the instructions of the system operator or in response to market signals. Even sources like nuclear and CCS, while in principle dispatchable, have very high capital costs. In economic terms, it will be difficult to operate them at low load factors or in a flexible manner.
- **Diversity** is recognized as being at the heart of energy security. Yet the transition to low-carbon sources is, at least at present, threatening to lead to decreased diversity. It is partly a matter of the sources themselves—in recent years, more than 70 per cent of new capacity has been from renewable sources, mainly wind and solar power, while there have been closures of conventional capacity. According to ENTSOE, renewable sources will account for over half of capacity in 22 EU countries by the mid-2020s (ENTSOE 2014). The decline in diversity will be compounded by the extent of correlation in output from these sources—wind conditions across large parts in the north-west of Europe tend to be broadly similar, so a large part of the wind generation fleet is likely to be operating (or off-line) at the same time. Solar power may vary more across the region but is subject everywhere to the diurnal cycle.
- **Cost structure**. As noted above, electricity pricing has

traditionally been based on marginal costs (kWh), reflecting an underlying cost structure in which the majority of costs were marginal (fuel). But with most of the low-carbon sources these will be mainly capital; their marginal costs are very low or zero.

- **Operating regimes**. In the past, plants have normally been dispatched by price, with those bidding the lowest prices dispatched first. But many renewables, like wind and solar PV, operate in response to weather conditions rather than price signals. In any event, under Article 16.2 of the EU Renewables Directive, renewable sources have priority in dispatch and should thus be allowed to operate whenever they are available, provided it is safe for them to do so.
- **Remuneration**. In a normal market, investment and operating costs are remunerated by income from the market. However, most of the remuneration for renewable sources (and with the growth of capacity payments, some of the remuneration for fossil sources) will come from outside the main market. Investment will increasingly be determined by government-set prices rather than market prices (or forecasts of market prices).

The underlying problem is that the new supply technologies do not fit well into a system designed to discriminate, by price, between sources with different marginal costs but some degree of flexibility. It is leading to problems for utilities across Europe (OIES 2015): a deterioration in the finances of utilities; plant closures; a move away from price convergence across Europe; and pressure for the introduction of capacity payments and so on.

A specific example of the distortions can be seen in the growing disconnection between different parts of the market. Wholesale power prices have been on a downward trend across Europe, as shown in **Figure 6.1**.

Meanwhile, the total cost of the system has been increasing because of the higher costs of the new renewables sources being introduced into the system. These higher costs lead to higher bills for consumers.

In other words, wholesale prices, industry costs, and retail

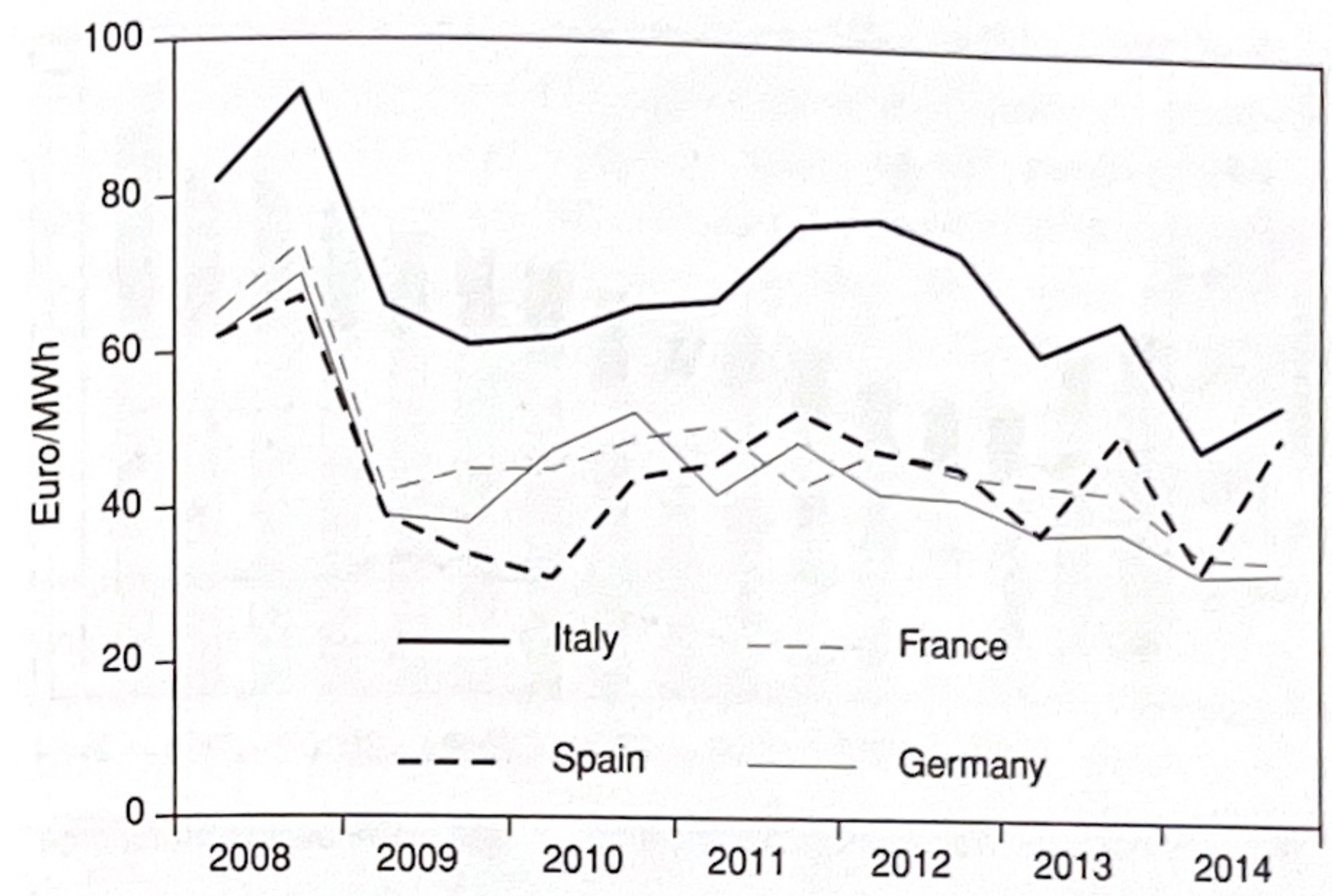

Figure 6.1: Wholesale market prices in selected EU countries 2008–14

Source: OIES 2015

prices have all been moving in different directions, as summarized in **Figure 6.2**; this relates to Germany, where the process of introducing renewables has been fastest.

Another outcome is a flattening of the intraday price curve, which shows the level of prices at particular times of day, as shown in **Figure 6.3**.

Paradoxically, this flattening (that is, the lowering of prices during the middle of the day) is due to the introduction of high-cost sources, like solar PV, which generate during the day, pushing down daytime prices. This leads to a further disconnect between costs and prices, and it undermines price signals for consumers—the flatter the price curve, the less the incentive for flexibility in demand.

Continuing on this basis leads to major inefficiencies, not just as a matter of particular circumstances but of fundamental market design. Not only are there no useful signals for operation or investment for many plants (which rely on FiTs rather than market prices), but the market itself is distorted. Low-carbon plants with FiT or other support create what are called '**pecuniary externalities**' (i.e. the FiT-supported plants reduce the

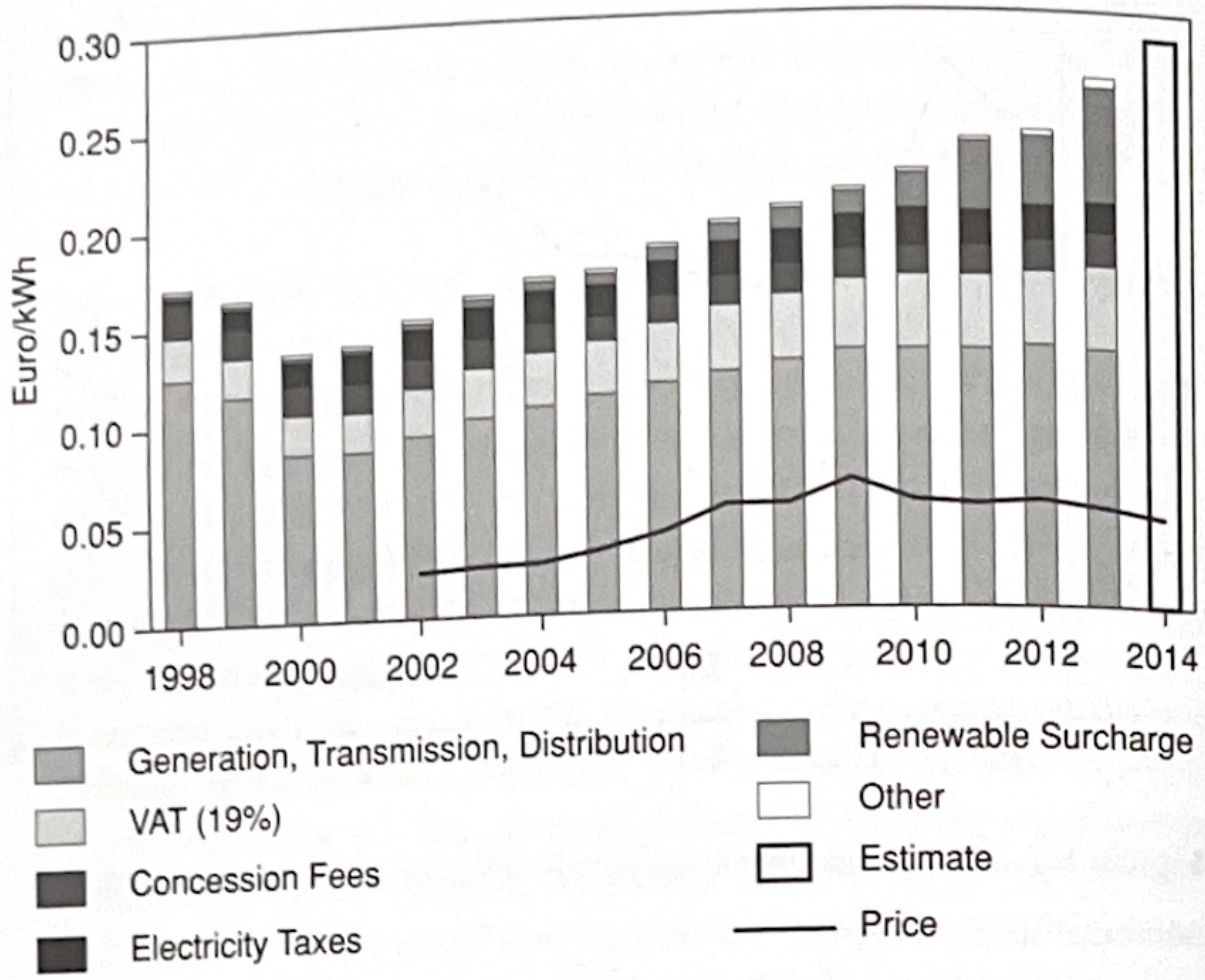

Figure 6.2: Disconnect between wholesale and retail electricity prices in Germany 1998–2014

Sources: BDEW; Moody's

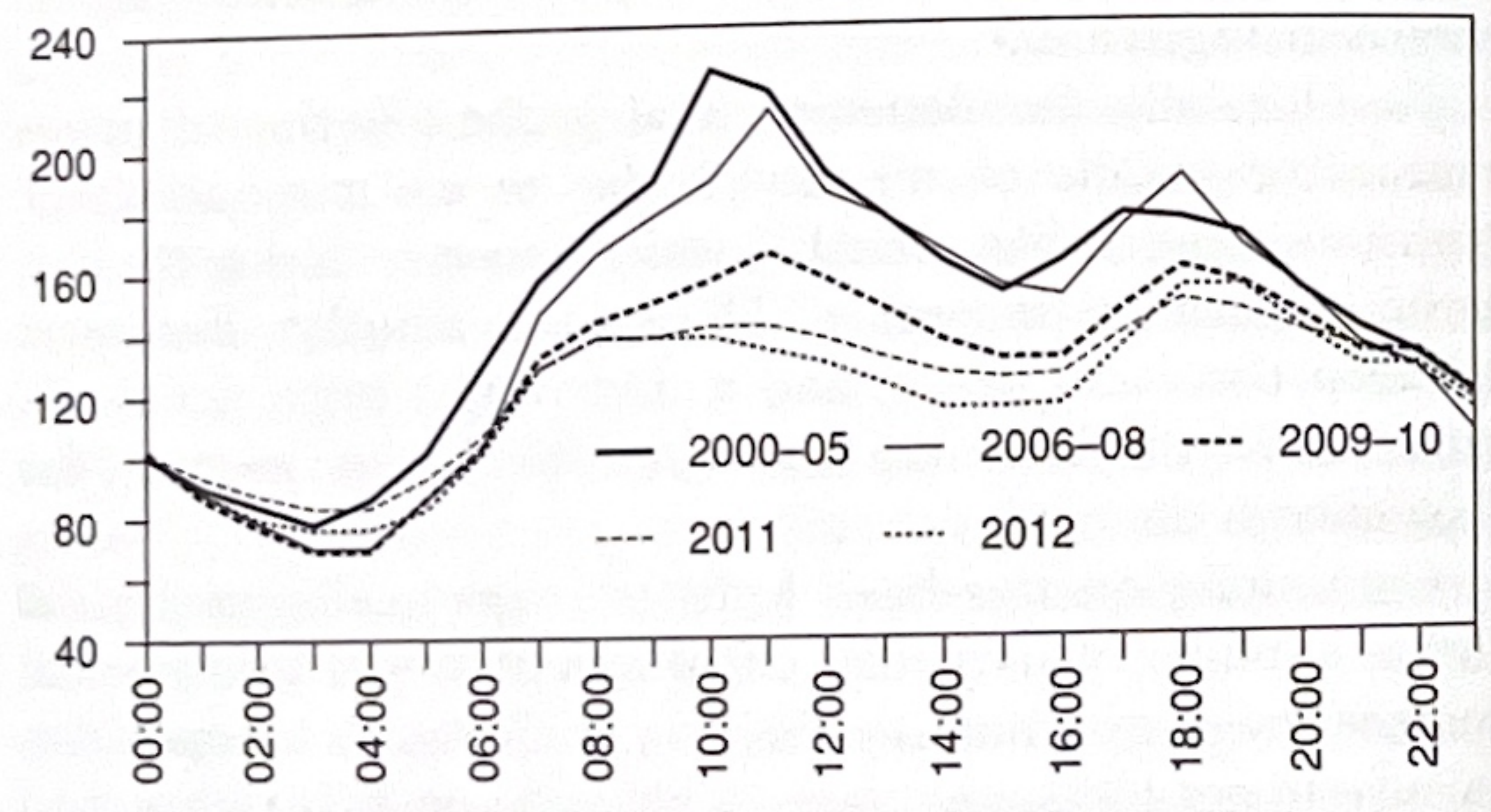

Figure 6.3: Average intraday power price profile change in Germany 2000–12

Source: Bloomberg

price being received by other plants) (OECD 2012: 34–7). In a normal market, this would simply reflect the process of competition by which low-cost suppliers entering the market tend to pull down the price for all producers. But in a normal market, the new entrant has to live (or otherwise) by market prices. In European markets today, FiT-supported plants do not depend (or do not depend wholly) on the revenue they receive from markets, because they have their FiT payments independently of (or in some cases additionally to) the market revenue. If markets were performing their normal functions, the decrease in market prices from the introduction of the new sources would be a signal for closures or disinvestment (more likely, in practice the plants would not have been built in the first place, because they could not rely on getting remunerated by the market), leading to price increases back to the level where all generators would have their costs covered. So in a normal market, these plants would not exist in the quantities governments are aiming at; but since they do exist, their presence in the market along with other suppliers distorts the market for all suppliers (including the FiT-supported plants themselves).

Less widely recognized is the fact that there is **no clear exit strategy**—that is, no possibility of a long-term, self-sustaining low-carbon market based on the mixture of sources envisaged by governments. As long as governments are pushing the new inflexible plants onto a market which is designed to encourage flexible technologies, the new sources will not get a market return (unless there is a fully diversified mix of such sources, which effectively mimics the conventional cost structure by having a significant element of dispatchable sources with positive marginal costs, such as biomass. But, as discussed in the previous chapter, there is no mechanism within existing systems of support or market structures to produce such an optimized system).

Take, for instance, a system with a high proportion of wind power subject to broadly similar wind regimes: prices will tend to be low or zero when these intermittent sources are operating at full capacity. It is only during periods when the intermittent sources are operating below capacity (or not at all) that prices will be set at a level which reflects the marginal costs of fossil generators. During these high-price periods, it is likely that no, or very few, intermittent generators will be operating (since it is their absence that is the cause of the high prices). This means that wind generators will not be able to rely on energy markets to cover their capital costs from the market alone.

It should be noted that this will be the case:

- **even if** the wind power is competitive in the sense of producing power at a 'levelized cost'[2] below that of conventional power (because the intermittent generator will receive a below average price, for the reasons explained above); and
- **even if** there is a high carbon price (since the carbon price affects high-carbon generators and hence only affects electricity prices significantly when they are generating, such as at times of peak demand but low renewables generation; conversely, the price of electricity will be little affected in situations when generation is solely or mainly from wind and other intermittent renewables).

So even if the cost of wind or other renewable sources attains 'grid parity' and even if there is a significant carbon price, the energy-only market will not provide a secure basis for remunerating investment in intermittent renewables if they are built in the quantities which governments want. They will continue, as at present, to need some other route to covering their capital costs, such as FiTs. In other words, there is a problem for investment in renewables just as much as for investment in reliable capacity from fossil sources. Although current discussions are focusing on the capacity issue, in the longer term the renewables issue is more fundamental.

There is no way out of this problem and no roadmap to a self-sustaining low-carbon market either in the Commission's Target Model (OIES 2013a) or the latest market redesign proposals, or, for that matter, in the UK Electricity Market Reforms (OIES 2011a). Even if the systems of support for renewables are changed to give the market a bigger place, as discussed in Chapter 5, for instance via 'premia' (i.e. additions to the market

2 The cost calculated by taking all the costs involved in constructing and operating a particular plant concerned; projecting total output from the plant during its lifetime; applying an appropriate discount rate; and then deriving a cost per unit of output.

price) or 'Contracts for Difference' (as in the UK) rather than fixed price support via FiTs, the same underlying problem remains: as long as some (low-carbon) producers receive this support and other (conventional) producers do not, the subsidized producers will be facing different investment incentives but, by selling into the same market, will distort market prices. Nor will carbon prices set by the ETS resolve the problem of creating a sustainable long-term market, for the reasons previously explained. New ways of remunerating supply capacity in the market, based on the cost structure and operating characteristics of the new sources, are needed.

It is not clear how far the Commission recognizes the problem—in the past it has seemed to hope that as the competitiveness of renewable sources grows, they can gradually move to a position where they can be built and operated without support. There were signs in its Energy Union 'Framework Strategy' document that its thinking was developing, particularly when it said that 'market integration of renewable electricity generation requires flexible markets, both on supply and demand side, within and beyond a Member State's borders'. It also declared that:

> The Commission will prepare an ambitious legislative proposal to redesign the electricity market…This will…ensure that the electricity market will be better adapted to the energy transition which will bring in a multitude of new producers, in particular of renewable energy sources, as well as enable full participation of consumers in the market, notably through demand response. (COM 2015a: 10)

In practice, however, the proposals put forward by the Commission in July 2015 (COM 2015b) deal mainly with balancing, intraday markets, and the like, and raise a series of questions about future arrangements; they do not deal with the fundamental problems. They are aimed primarily at improving the flexibility and responsiveness of markets in the short term, but they largely stay within the existing framework of the energy-only market; they do not really justify the word 'ambitious' or demonstrate that the Commission is prepared to think about the problem in a fundamental way. Indeed, in some ways, they seem to represent something of a retreat from the initial

Framework Strategy document, which promised legislation on the electricity market, as already noted. This would have been something of a new departure, as the single market has to date relied primarily on codes agreed between market participants. Although these codes, once agreed, have the status of secondary legislation, the Commission strategy document seemed to be promising something more. However, the market design consultation document is rather cautious; it is based on questions as much as on answers, and it talks about 'any future legislative and non-legislative proposals' (COM 2015c: 16) rather than containing any particular suggestion for a new legislative basis for the electricity market.

In some ways this caution is surprising. At the same time as the market design proposals were published, the Directorate-General for Economic and Financial Affairs published a paper entitled 'Investment perspectives in electricity markets', which contains an analysis of the problems with wholesale markets in the EU, drawing attention to many of the issues listed earlier in this chapter. It concludes that 'in the long term, it is uncertain whether wholesale prices based on existing market arrangements will be able to provide the revenues necessary to cover the total costs of investments' and that as a result 'the market design may need to evolve'. In view of what it calls 'the inertia of the energy system' it argues that 'this calls for starting a reflection already now' (SWD 2015b: 73). It is disappointing that the Directorate-General for Energy has not responded to this challenge in its market design proposals.

It may be that the problem simply seems too difficult. If the Commission were to accept that it needed to rethink the whole basis of electricity market design, it would open a complicated can of worms and might risk jeopardizing progress to date in developing the single market. The 'investment perspectives' paper is itself relatively cautious, putting forward some evolutionary ideas like more scarcity pricing and an EU-wide capacity market. However, it also mentions another, more radical, strand which 'could be further explored' based on an EU-wide market for long-term contracts based on average-cost pricing. This would be a major departure. Hitherto, the EU has been rather resistant to long-term energy contracts, which tend to foreclose the market and limit competition. Marginal pricing, as in the Target Model, rather than average pricing, has also been regarded as the best way of giving effective signals to consumers about the costs they impose on the system. However, the general idea of long-term contracts for investment, supplemented by short-term markets for energy, has received some support from outside experts (Agora 2013; FTI 2015) and is similar to the model followed by a number of Latin American countries which have a high proportion of (low marginal-cost) hydro plants.

In any event, it could not really be said that any consensus on the subject has emerged. Other ideas might involve putting more emphasis on maximum demand pricing rather than unit pricing (so that a higher proportion of consumer bills came in the form of fixed-price elements, and that support to low-carbon producers put more emphasis on subsidizing the initial capital requirement rather than each unit of output). There are also more radical options, such as:

- 'transactive pricing', under which retail consumers would be able to contract separately for transmission capacity and energy supplied; and
- the 'two-market model', which would create separate markets for subsidized 'as available' power and flexible 'on demand' electricity, in order to let consumers decide for themselves on the degree of reliability they needed. (Sioshansi 2014: Chp 8 & 10)

However, the range of options and the complexity of the issues involved is likely to mean that any major proposals for change would be very difficult to agree among member states. Any such proposals would have far-reaching consequences at national level as well as in intra-EU trade (as noted earlier, the Commission has referred to the need for flexible markets within as well as beyond national borders). Furthermore, if appropriate signals are to be passed through to consumers from wholesale markets (unlike the present disconnect between the two markets described above) any redesign of wholesale markets ought to be reflected at retail level. This means that there would be major changes for consumers as well as for the industry itself. The previous chapter mentioned the 'embarrassingly long delays' in negotiations over the current, relatively evolutionary, proposals. Member states and utilities are likely to resist further change of any sort, let alone ambitious changes, and could point out that they are still in the process of adapting to the present Target Model. Whether a fundamentally new system could be agreed within a reasonable time, or indeed at all, must be open to question.

Conclusion

The Commission seems to be facing a fundamental problem. To achieve the energy transition it is aiming at, it needs to re-design electricity markets to be consistent with its environmental goals. Electricity markets across Europe are broken and are not giving effective signals for operation or investment, either to conventional sources or to the new renewable sources. If sustainable markets are to be designed for the low-carbon future, fundamental changes will be needed. But it is doubtful whether there is any consensus among industry participants or member states to make such radical changes, and the Commission does not appear to have the will or the means to deliver such major reforms. While it seems to recognize the problem, its current proposals for reforming electricity markets do not go nearly far enough to remedy it. Without a more strategic vision in this area, uncertainty is likely to persist and market distortions to get worse, until such time as the need for reform becomes so great as to be undeniable—by which time substantial damage may have been done and huge unnecessary extra costs incurred. There is a risk that the fundamental transition in energy markets, which the Commission describes as its goal, may be seriously compromised.

CHAPTER 7

NEEDED: A DEMAND-SIDE STRATEGY

Introduction

Energy policy, including EU energy policy, has traditionally focused on the supply side. For instance, energy security is generally defined as 'security of supply' rather than in terms of an active role for consumers in the matching of supply and demand.[1] Climate change objectives are also being met largely through action on the supply side of energy. The degree of intervention there—for example, in supporting low-carbon generation—has consistently been much higher than on the demand side. A recent EU study (Ecofys 2014: iii) suggested that some 70 per cent of the intervention total, in terms of the resources devoted to the measures, goes to support for production, with a mere 8 per cent or so on energy efficiency (and a negligible amount on demand response). Perversely, the largest single form of intervention on the demand side is via preferential (lower) levels of taxes on energy for some groups of consumers (for instance, lower rates of Value Added Tax on domestic energy consumption or lower carbon taxes for carbon-intensive industries), a practice which undermines climate change policy by encouraging the use of energy.

The only partial exception to this supply-side orientation is energy efficiency, which has always been a policy mainstay, at least in terms of presentation, if not substance. Yet there is much more to the demand side than energy efficiency, and developing a full understanding of the demand-side resource and integrating it properly into overall energy policy will be one of the main challenges for policy makers over the coming decades.

1 See, for instance, the Commission's description of EU energy security at http://ec.europa.eu/energy/security_of_supply_en.htm. Similarly, the UK government produces a Statutory Security of Supply Report, jointly with Ofgem.