CHAPTER 4

THE CLASH: LIBERALIZATION VS INTERVENTION

The interaction between Europe's energy and climate policies creates multiple tensions. One of these is the increasing friction between liberalization and intervention. EU policy-makers continue to apply their traditional model of market-opening liberalization to an energy sector in which national governments increasingly intervene in their home markets in order to support renewable energy technologies or to guarantee security of supply. This is fragmenting the market between subsidized and non-subsidized energy. It is also segmenting it geographically, along national lines, because the subsidies are designed and paid nationally. From this it might almost seem as though there is one set of (EU) policies supposed to make energy flow across borders and another set of (national) policies aimed at stopping the flow. In fact, it is not so simple, because it is largely only in order to implement EU-agreed climate goals that member states are intervening in their national energy markets, using national means (renewable subsidies) that so far happen to have proved more effective than EU-wide instruments like the ETS. There is also the element of a race against time in this conflict between liberalization and intervention. The forces of intervention gain influence as the volume of renewable energy, currently subsidized and organized on a national basis, grows every year at the expense of the shrinking non-subsidized sector.

The aim of this chapter is to illustrate the work of EU-scale market unification and to show how it has been outpaced by the dis-integrationist impact of national intervention. Subsequent chapters focus on whether the problem of geographic segmentation can be tackled by putting national renewable subsidies and capacity payments on a regional, if not European, basis. They will also consider whether renewable electricity can ever be integrated into the conventional power market.

A. Market unification

At the heart of this is the work carried out by the European organizations of ACER, ENTSOE, and ENTSOG. They have been following an agreed blueprint, or 'Target Model', for the architecture of both electricity and gas. The aim in each sector is to harmonize cross-border trading arrangements and link national markets through efficient use of infrastructure carrying electricity and gas to where they are most valued. Critical to this construction job are so-called network codes that, in a sense, provide the plumbing in all the joints of the system so that energy trade can flow smoothly.

Electricity. The aim of market integration in electricity, as in all sectors of the European economy, is to encourage cross-border trade in the hope that this will produce more competition, efficiency, and wholesale prices which, if not lower in absolute terms, are at least lower than they would otherwise be. The growth rate of cross-border electricity flows started to rise in the late 1990s as the Commission began to push through its market-opening legislation (as described in the previous chapter). The increase would have been greater, however, if such trade had not hit a growing problem of transmission capacity congestion that so often occurs at national borders in a system originally designed around independent nation states.

Electricity infrastructure: the software. Dealing with this congestion is a main aim of the 'Target Model' for electricity. The idea is to progressively harmonize power trading arrangements along a timeline that starts with the day-ahead market and moves eventually to providing a single continuous platform for intraday trading. This ultimate goal is important for renewable energy suppliers who need to trade as near as possible to 'gate closure', or the time of actual delivery, in order to take account of weather-related variations in their supply and so to minimize the imbalances they can cause in the system.

The main instrument for achieving this is 'market coupling', which is used to optimize the use of existing interconnections. Among other things, it is designed to avoid the situation in which a seller of power on one side of the border gets a deal to deliver the power to the other side of the border but then finds he cannot get the capacity to transport the electricity. Market coupling allows buyers and sellers to trade electricity without explicitly having to separately buy the transmission capacity to complete the trade. The way it works is that a power exchange, or usually two (one on either side of a border), will take all the trans-border transmission capacity that the TSOs have declared available for any period of time and, by use of a clever algorithm, automatically allocate this capacity so that one country will continue to export to another for as long as the selling price in the first country is below the bid price in the second. This allocation of transport capacity (paired automatically with trades in the electricity itself) goes on until prices in the two markets converge or until all available cross-border capacity is used up, whichever happens first. The system allows transmission capacity to be used efficiently and prices to act as a signal for the logical flow of electricity, from lower price to higher price areas. As a result, it reduces 'adverse flows', or economically wasteful flows, from higher to lower price areas.

As regards the trading of electricity in the day-ahead timeframe, market coupling has proceeded apace. Pioneered in the late 1990s by Nord Pool in Scandinavia, the method evolved into a 'trilateral' coupling between France, Belgium, and the Netherlands in 2006, before becoming a 'pentalateral' coupling when Germany and Luxembourg joined in 2010. Fast forward to 24 February 2015, when Italy achieved market coupling on its borders with France, Austria, and Slovenia, and so became the 19th country in Europe's coupled day-ahead power market. The other 18 are Austria, Belgium, Denmark, Finland, France, Germany, Great Britain (i.e. without Northern Ireland), Luxembourg, the Netherlands, Norway, Poland (via its link with Sweden), Portugal, Slovenia, Spain, Sweden, and the three Baltic states of Latvia, Lithuania, and Estonia via the latter's new electricity links with Finland. Switzerland, in the middle of this area, is still uncoupled, not for technical reasons, but because it has some unresolved political issues with Brussels. In a further integration move in May 2015, the core pentalateral countries that make up the Central Western Europe (CWE) group launched something called 'flow-based' coupling of their electricity markets, which essentially increases the amount of cross-border interconnection capacity available for coupling.

However, there is a drawback to this integration success in the day-ahead market, which is naturally still dominated by generators of conventional electricity who can confidently forecast their output 24 hours in advance. The drawback is that the day-ahead market is of decreasing relevance in a system with an ever-growing percentage of wind and solar power that is necessarily less predictable because of reliance on the weather. In its electricity market design proposal of July 2015, the European Commission stressed that 'short-term markets, notably intraday [meaning trading within the same day as delivery] and balancing markets, must be at the core of an efficient electricity market design' (COM 2015c: 5). Until very recently, there appeared to be no solution in sight for a common intraday platform for trading and balancing electricity from when the day-ahead market closes to about half an hour before gate closure. There are several causes for this according to European regulators and officials. One is the technical difficulty of designing a platform which will allow parties to bid anywhere across Europe for short-term balancing power and where available capacity will require fast and constant updating.

However, the root cause of the impasse appeared to lie with the involvement of power exchanges in the negotiations. Power exchanges are vital to the process, but while they are supposed to be cooperating with each other in the public interest, they are also commercial entities competing with each other. It seems they fear that, in making the compromises necessary for progress, they might lose business to each other in this increasingly important slice of the electricity market. It also has to be said that up to now there has been no great industry pressure for an EU-wide solution from generators or traders, most of whom are satisfied with the national intraday power markets that exist in most EU countries with a big renewable sector.

In late 2014 the director of ACER, Alberto Pototschnig, was moved to complain of the 'embarrassingly long delays' in negotiations, saying that 'very little tangible progress has been achieved over the last two years and at the end of 2014 we have once again to report that there is not yet a credible timetable for the deployment of a single intra-day capacity allocation platform'. Pointing the finger at the power exchanges, he said 'the stalemate is caused by the conflicting interests of some of the parties involved and an inadequate governance of the process' (ACER 2014: 3–4). However, the advent of the Energy Union plan has at last acted as a catalyst for progress. In June 2015, Europe's leading power exchanges finally agreed a contract with Deutsche Börse for the latter to design a common intraday trading platform that would go live in 2017. The delay has frustrated the Commission, which attaches a great deal of importance to the harmonization of short-term trading and the power exchanges' role in this. In its July 2015 market design proposal, the Commission suggested it wanted to bring power exchanges into line with its policies:

> Strengthening the regulatory framework may also require integrating entities which currently are not subject to regulatory oversight, such as power exchanges which play a crucial role in coupled European electricity markets and perform also functions which have characteristics of a natural monopoly. (COM 2015c: 12)

Another issue of governance, and source of delay in integration, has been the time taken to negotiate network codes for gas and electricity. Agreement on new EU network codes, which replace national ones, is vital to harmonizing cross-border trading arrangements. The Capacity Allocation and Congestion Management (CACM) code is probably the most important of these in relation to cross-border trade. It defines how capacity should be assessed and allocated, and it deals with congestion by setting a rule about firmness of orders and what happens to firm orders if transmission capacity is subsequently constrained. The CACM code should win approval this year, but, like other network codes, it has been a long time in the making. Agreeing on network codes typically takes at least three years. This is the result of a cumbersome process in which ACER has six months to produce framework guidelines for the ENTSOs, which in turn have 12 months to draft a code. ACER then has a further three months to recommend adoption or ask for more work. All this takes place under the supervision of the Commission.

If and when that process is over, the draft network code goes into comitology—the name for an arcane process of secondary law-making by officials of the Commission and of the member states—and emerges as a binding rule on the energy industry. Any changes in governance as a result of the Energy Union plan might usefully speed up this process.

The progress that has been achieved in coupling markets and agreeing network codes should have brought price levels in different EU countries and markets closer together. Cross-border price convergence is the standard measure used across all sectors of the EU economy to determine the degree and effectiveness of cross-border competition and trade flows. Because retail end-user prices are heavily influenced by national governments, both through taxes and in many cases regulation, the relevant focus is on wholesale prices.

In recent years, wholesale price levels did begin to converge in the main Central Western Europe (CWE) regional group of France, Germany, and the Benelux markets; more erratic has been the pattern in the Nordic countries' Nord Pool market, which relies heavily on hydroelectricity, the price of which is affected by rainfall and reservoir levels. Since 2012, however, the surge of renewable power, and the influx of cheap coal entering the German market from outside the EU, has helped drive prices in Germany lower than levels in neighbouring countries. Indeed, the wholesale spot price in Germany (and in its linked market with Austria) often now goes negative, something that never occurred before 2008 but which now happens several dozen times a year (for instance, on 64 occasions in 2014). A factor contributing to this bizarre phenomenon, whereby German generators occasionally have to pay the grid to take their electricity, is that due to a lack of adequate interconnections with neighbouring markets, they have nowhere else to dispose of power that is excess to domestic German demand. The supply/demand imbalance in Germany is also accentuated by insufficient connection between the wind power production regions of northern Germany and the industrial electricity demand centres in the south, where a number of nuclear reactors have been taken offline.

Taken to its logical extreme, the electricity Target Model would produce a single wholesale price across Europe. It is not clear such an extreme outcome would be necessary—indeed it might even indicate that the EU had over-invested in interconnection. This, however, is far from the situation today.

Electricity infrastructure: the hardware. The previous passage set out the efforts to get the most out of available physical cross-border infrastructure. In other words, how to make the best out of a bad job—because the current level of electricity interconnection between member states is inadequate, woefully so on certain borders. According to ENTSOE, interconnection capacity will (on average) have to double by 2030, driven mainly by the need to link ever-growing sources of renewable electricity to centres of consumption (ENTSOE 2014: 10).

The main reasons for the relative paucity of cross-border interconnections are fairly straightforward. Europe's member states designed their power systems to serve themselves, not each other. Interconnections are high-voltage power lines, which are very obtrusive if attached to pylons and even more expensive if buried. They therefore attract considerable environmental opposition, as was the case with a controversial 65km Franco-Spanish power link which was first proposed in the 1990s; only in 2015 was it decided that the line should cross the Pyrenees in a tunnel and be buried in trenches on both the Spanish and French side. For quite some time the European Commission was also convinced that national TSOs, especially those with ownership ties to electricity generators, might be deliberately underinvesting in cross-border interconnections in order to keep foreign rivals out of their domestic supply markets. It was in order to remove this possible conflict of interest that the Commission strove to unbundle, or separate, TSOs from any energy supply business in its three packages of energy legislation over the 1996–2009 period.

The third package of legislation in 2009 also created ACER, the grouping of national regulators, partly in order to try to settle national regulatory differences and disputes over interconnections between member states. A frequent problem has been the mismatch of costs and benefits on a national basis. If country A incurs the bulk of the investment cost but country B gains most of the benefit, then country A's regulator will

be disinclined to give country A's TSO much of a return on its investment. The idea of ACER is to get national regulators to take a less nationally-minded view of the benefits of interconnections.

However, the 2009 changes do not seem to have satisfied the Commission and EU leaders, who have now returned to the blunter—and very EU—approach of setting a fixed target for cross-border power connections. In 2002, EU governments agreed that every member state should have interconnection capacity equal to at least 10 per cent of its total electricity generating capacity. However, as **Table 4.1** shows, 12 countries still fall below that threshold. So in October 2014, when they signed on to the EU's 2030 targets and the Energy Union concept, EU leaders renewed their vow for all member states to meet the 10 per cent ratio by 2020 and indeed to raise this to 15 per cent by 2030. Do arbitrary targets of this kind make sense? Not to ENTSOE, which has criticized this one-ratio-fits-all approach as inappropriate for the widely differing situations on Europe's internal energy borders, which in some cases manage to combine high levels of interconnection with high levels of congestion. ENTSOE would prefer that Europe's politicians draw their infrastructure priorities from the rolling Ten-Year Network Development Plans that it develops every two years. However, while the instrument of the 10 per cent or 15 per cent targets may be crude, the political impetus for interconnection building may be useful.

This new effort to physically link electricity markets builds on a number of previous initiatives. First came the European Energy Programme for Recovery, which was launched in the wake of the 2008 financial crisis and which put €650m into electricity interconnections. Then there was the 2013 energy infrastructure regulation (Council Regulation 2013). This established a certain number of 'Projects of Common Interest' (PCIs), most of them cross-border interconnections, and for the first time streamlined national planning procedures for these priority projects. It requires member states to concentrate permit-granting powers in one competent authority (a 'one-stop shop') and limits the time allowed for granting permits to 3.5 years, compared to the current average of 10–13 years.

Table 4.1: Cross-border electricity interconnection as ratio of total generating capacity in 2014

Member states above the 10% threshold	
Austria	29%
Belgium	17%
Bulgaria	11%
Czech Republic	17%
Germany	10%
Denmark	44%
Finland	30%
France	10%
Greece	11%
Croatia	69%
Hungary	29%
Luxembourg	245%
Netherlands	17%
Slovenia	65%
Sweden	26%
Slovakia	61%
Member states below the 10% threshold	
Ireland	9%
Italy	7%
Romania	7%
Portugal	7%
Estonia*	4%
Lithuania *	4%
Latvia*	4%
United Kingdom	6%
Spain	3%
Poland	2%
Cyprus	0%
Malta	0%

* The three Baltic states are interconnected amongst themselves (and to the Russian grid), but only have limited connection with the rest of the EU

Source: European Commission (COM 2015b)

These PCIs are eligible for some EU finance, both from the EU budget (out of structural funding for poorer member states and out of a special energy infrastructure fund of €5.35bn over

the 2014–20 period) and from the European Fund for Structural Investment proposed by the Commission at the start of 2015. This EFSI is to have EU seed money of €21bn (€16bn from the EU budget and €5bn from the European Investment Bank) in order to mobilize over €300bn in private and public investment. It is doubtful whether this target will be reached, and it is even more doubtful that the EFSI, which aims to help many sectors beyond energy, will make much impact on perceived energy infrastructure needs in this decade. The Commission estimates that around €105bn needs to be invested in electricity infrastructure by 2020, of which €35bn will need to be spent on interconnections for all states to meet that 10 per cent target.

Gas. Unlike electricity, which is mostly generated and consumed within national borders, gas has always flowed across the EU's internal and external boundaries. A large and increasing portion of Europe's gas comes from far away, whether transported by pipeline or LNG, and usually crosses several EU borders before reaching its destination. This is the inevitable result of decreasing production within the EU (primary production in **Figure 4.1**) and increasing imports. The transport regime is therefore crucial for gas.

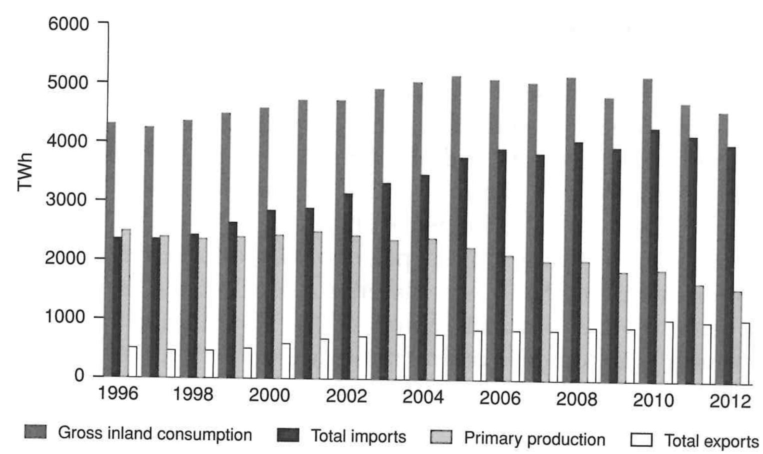

Figure 4.1: Falling domestic gas output, rising imports

Source: European Commission (SWD 2014a)

Gas infrastructure: the software. In unifying and simplifying the transport of gas across the bloc, the EU has chosen as its basic building block so-called entry-exit zones (EEZs). These are required by the third package of legislation, which stipulates that transport tariffs should be independent of 'contract paths', or the actual distance between the source of gas and the point of consumption. Gas can enter at any point or leave at any point within these EEZs at prices that are not directly connected to the distance which that gas has travelled.

European countries used to have a system that more closely resembles that of the US, in which the inter-state transport and trading of gas is largely governed by long-term contracts. In the US, transport tariffs are calculated on a point-to-point system and take account of the underlying infrastructure costs. Trading takes place at physical hubs, such as the famous Henry Hub, formed by pipelines coming together and also providing a useful location for storage and balancing. Underpinning this point-to-point system were well-defined property rights to, or long-term contracts for, transmission capacity that had been key to funding the building of the long-distance pipelines within the US and also between Russia and Western Europe.

Had this system been retained, many of the recent contractual problems that have arisen with Russia's Gazprom would have been avoided.[1] However, partly because the system appeared to suit Gazprom and some other foreign suppliers all too well, the European Commission decided that many of the long-term gas transport contracts were effectively cosy arrangements between Europe's gas importers and outside suppliers that cartelized the market against new entrants. The Commission also decided that the contracts also helped sustain the increasingly artificial pricing of gas by indexing its price to oil product prices. So the Commission chose the very different model of EEZs in order to promote new entrants, competition, and trading at virtual gas hubs that could be at any notional point within an EEZ. It so happened that the model had already been successfully put into practice in the 1990s in Great Britain, the pioneer of gas liberalization in Europe, which had turned itself into a single gas trading market with a virtual hub known as the National Balancing Point (NBP). This was the only working model of competition at the time, so the Commission adopted it. For the Commission there was also the ideological attraction of EEZs as mini-versions of Europe's single market.

1 For a thorough discussion of this issue, see 'The EU Third Package for Gas and the Gas Target Model', Katja Yafimava, OIES (2013)

The EEZs, which coincide with balancing zones, facilitate trading in several ways and use a simplified commercial model to promote more efficient market functioning. They expand the trading zones, with usually only one EEZ per country (as in the UK and Italy, though Germany has two EEZs and France three), and they lower transaction costs because any gas is priced and traded regardless of its location within the EEZ. Balancing—to equalize injections and withdrawals of gas—becomes easier in a larger zone, and therefore the timeframe for balancing can be extended. The cost of transport and network services is separated from that of the commodity and is 'socialized', or spread across all users of the EEZ network. Trading has become simpler (fewer transactions) and less risky (less worry about imbalances and mismatched trades). So trading activity has surged at Europe's hubs.[2] Liquidity attracts liquidity, as buyers and sellers benefit from always being able to get a good price, and Europe's gas consumers can be more certain of purchasing gas on a market where large volumes make prices difficult to manipulate.

However, there is a trade-off to the size of EEZs: they have to be large enough to attract buyers, sellers, traders, and shippers, but they have to be small enough that any physical constraints do not generate high internal congestion costs and problems. Distance may have been 'abolished' commercially inside the EEZ, but gas still has to flow physically within it. A TSO will always keep part of its infrastructure capacity out of the market in order to respond to requests for shipment in and out of any entry or exit point of the zone. The larger the zone, the more capacity has to be held in reserve and the greater degree of cross-subsidization, with shippers

2 See 'Continental European Gas Hubs: are they fit for purpose?' Patrick Heather, OIES (2012)

that use little transport effectively subsidizing those who use a lot. A further complication is that within the EEZs there are no locational price signals, or price spikes at particularly bad bottlenecks, to pinpoint congestion and incentivize investment in new pipelines to relieve the bottlenecks. As a result, there could be underinvestment in new gas pipelines at a time when more cross-border interconnectors need to be built to improve security of gas supply and the EU's resilience to any external energy shock, such as a cut-off of Russian gas.

For some of these reasons it is hard to see individual EEZs being enlarged much further. Most will probably stay at the national level in size, some may stay sub-national, and there will never be a single EEZ for the whole of the EU. Therefore, the issue is how to improve the links between EEZs and make best use of the interconnector capacity between them. One possibility might seem to be to use the market coupling tool already used in electricity. But so far this has only been carried out between the Netherlands and Germany due to the rather exceptional fact that Gasunie happens to own the gas grids on both sides of the Dutch-German border. Generally, the gas industry has an aversion to trying market coupling because it sees the usual approach in electricity as appearing to put almost no value on transport, which is a very important feature of the gas industry. The gas industry's preference is to use the network codes that are being negotiated, specifically the Congestion Management Principles, which prevent capacity hoarding by clawing back unused capacity, and the Capacity Allocation Mechanism, which puts this unused capacity out to auction. However, there is still a problem for long-distance transport of gas across Europe. The capacity allocation process requires the mandatory bundling of transport contracts crossing from one EEZ to another, so that if gas leaves one zone it will always be allowed to enter an adjacent zone. But it cannot do this simultaneously across several zones, although this might well be the delivery route of a Gazprom consignment of long-distance Siberian gas, for example. To try to resolve this problem, a procedure is being developed within the amended Capacity Allocation Mechanism to allow coordinated allocation of capacity across several zones if certain conditions are met.

Generally, the parallel development of EEZs, and hubs within them, has led to a significant convergence in wholesale prices at gas trading hubs, although these are all in Western Europe. In turn, this has led to a rise in the share of gas priced and traded on the basis of gas-on-gas competition and, despite the best efforts of Gazprom and Algeria's Sonatrach to frustrate this, a decline in gas indexed to oil prices. However, there is still a pricing disconnect with some of Europe's eastern and southern areas that suffer from a lack of supply diversity, a paucity of connecting pipelines, a scarcity of LNG, and (because of all this) an absence of trading hubs.

Gas infrastructure: the hardware. The EU has set no simple benchmark for gas infrastructure comparable to the 10 per cent interconnection target in electricity. This is because, for practical and legal reasons, a reasonable level of interconnection already exists. Russian gas piped to Europe usually crosses several EU borders before reaching its final customers, and there is legislation requiring member states to provide for alternatives if and when their largest single source of gas were to fail (Council Regulation 2010). However, there is still a need to build more interconnections, especially more north-south and two-way links in a gas grid that was largely built to carry Russian gas in one direction—from east to west—first by the Soviet Union to supply communist Eastern Europe, and then extended from the late 1960s to supply Western Europe as well.

Until recently, the two main arteries for Russian gas were the Yamal pipeline, which runs east–west through Poland to Germany, and the Ukraine transit route taking Russian gas both through Central Europe to Austria and through Romania and Bulgaria to Greece and the Western Balkans. A third gas route opened in 2011—the Nord Stream pipeline, which provides a direct gas route from Russia through the Baltic Sea straight to Germany. These are the fixed connections that tie much of Europe's gas security to Russia. (The Druzhba pipeline carrying Russian oil through Ukraine to Slovakia, Hungary, and the Czech Republic does not create quite the same security concerns for these countries, because they can access alternative supplies of oil by truck or rail.) Gazprom's monopoly hold over individual

Eastern European gas markets has to a large extent rested on the fact that these pipelines could not be used to bring alternative supplies of non-Russian gas in from the west, the north, or the south. Therefore, one priority for the EU has been to build more north–south pipeline connections. This north–south axis exists through Austria, which is a gas trading hub and storage point linking Europe's northern gas markets to Italy, but is lacking further east. It could exist through Hungary, which is the biggest gas user in south-central Europe and now has gas connections with several neighbours, but until recently few of these were two-way interconnections.

The ability to reverse the flow of gas (by adapting or installing additional pipeline compressors) is important because it provides alternative supply routes, indirect access to gas from LNG terminals, and opportunities to trade and to increase hub liquidity. The increase in reverse flow capability in Central and Eastern Europe is already proving valuable to Ukraine, which has in the past year been able to draw on gas from Slovakia, Poland, and sporadically from Hungary in order to counter some of the impact of its supply problems with Russia. Of course, this reverse flow gas that Ukraine is getting from its Central European neighbours is physically Russian, but by the time it reaches Ukraine it is contractually European.

However, progress towards a more meshed, two-way gas grid has not been the product of pure market forces. This is not surprising: European gas demand is falling, or at best stagnant, and some gas infrastructure is seriously underused. Over the 2012–14 period, only around a quarter of LNG import capacity was used. There is congestion on a number of gas transport routes within the EU. However, as explained earlier, within the entry-exit zones which the EU has chosen as the model for market integration, there are no locational price signals, or price spikes at particular bottlenecks, to pinpoint congestion and to incentivize TSOs to invest in new pipelines to resolve the bottlenecks. Furthermore, some of the vulnerable member states, in terms of exposure to the risk of a cut-off of Russian gas, have gas markets which have low regulated retail prices, which means Europe's major gas companies are hardly rushing to reach them. Indeed, the only company ready to make major investments in new infrastructure in Europe in recent years has been Gazprom.

In order to get anything done, it has been EU policy-makers rather than the gas industry that has taken the initiative in encouraging the building of more gas infrastructure. Among other measures and methods, they have achieved this through the 2010 security of gas supply regulation (requiring reverse flow on new pipelines), the 2013 infrastructure regulation (streamlining planning procedures for priority projects), the Commission's 2014 energy security strategy (which singled out 27 gas projects—compared to only six in electricity—as vital to the EU's short- and medium-term security), and most recently through the Energy Union plan. Some countries or regions have needed less encouragement than others. The three Baltic states and Finland rely 100 per cent on Russia for their gas, but Finland has taken fuel-switching precautions, Latvia is ready to share its large gas storage with its neighbours, and Lithuania has acquired a floating LNG terminal to import non-Russian gas. So far the only long-term supply for this regasification terminal is a fairly small amount of gas from Norway's Statoil, but this has been sufficient for Lithuania to bargain down the price of its gas from Gazprom.

Other equally vulnerable countries have done less to help themselves. For some considerable time, Bulgaria counted on getting a direct feed of Russian gas via the South Stream pipeline landing on its Black Sea coast. Only now, after the cancellation of the South Stream project (see Chapter 10), is Bulgaria seriously working on a pipeline to draw gas from Greece's LNG terminal.

Intervention

Renewable energy subsidies. The most successful element in EU climate policy has been the deployment of renewable energy, but it has come at a considerable cost both in distortion of the market and in subsidies. As **Figure 4.2** shows, many member states were, even by 2013, quite near to reaching their national renewable energy target for 2020. This is a significant achievement, although the early gains in renewables may have been the easier ones, and the trajectory of the increase required for some countries to hit their final goal will become steeper nearer 2020.

However, the surge of subsidized renewables has exacerbated a problem of electricity generation overcapacity in Europe and exerted downward pressure on wholesale power prices. This is scarcely surprising, given that electricity demand fell by 3 per cent between 2008 and 2012, yet renewable capacity rose by

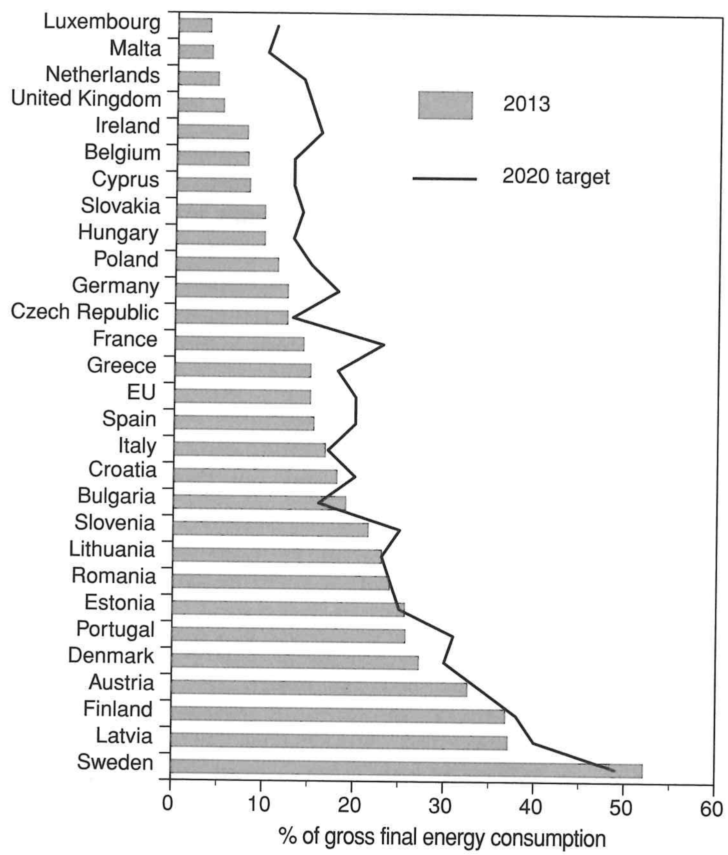

Figure 4.2: How member states fare in renewables

Source: Eurostat

Table 4.2: Renewable electricity subsidies in selected EU states 2012

	Renewable electricity subsidy (€million)	*Renewable electricity subsidy per unit of total electricity (€/MWh)*	*Share of total electricity getting RES subsidy*
Austria	361	4.97	9.1%
Belgium	1,490	17.97	11.6%
Croatia	22	2.13	3.6%
Czech Republic	1,268	14.48	6.6%
Denmark	568	18.48	55.9%
Estonia	17	1.42	9.8%
Finland	47	0.67	3.2%
France	2,488	4.41	5.2%
Germany	16,288	25.86	18.2%
Greece	1,165	19.11	10.5%
Hungary	99	2.86	5.4%
Ireland	56	2.03	15.0%
Italy	9,585	32.03	17.8%
Lithuania	49	9.78	16.5%
Netherlands	686	6.70	9.5%
Norway	4	0.03	0.1%
Poland	1,038	6.40	9.3%
Portugal	781	16.76	30.0%
Romania	190	3.21	5.7%
Spain	6,165	20.72	22.9%
Sweden	495	2.97	12.9%
UK	2,743	7.54	9.7%
Total	**45,605**	**13.68**	**12.6%**

Note: This review excludes some smaller EU member states and includes Norway, which is part of Europe's internal energy market through its membership of the European Economic Area, as an example of a country that can draw virtually all its renewable energy from unsubsidized hydroelectricity.

Source: Council of European Energy Regulators, Status Review of Renewables (2015)

50 per cent over the same period, adding 13 per cent to total electricity generating capacity (IEA 2014c: 111–12). Moreover, the cost of subsidizing renewables has risen sharply, reaching well over €40bn in 2012 (see **Table 4.2**) and over €50bn in 2013 (IEA 2014b).

The integration challenge posed by renewables is to reduce the differences between 28 national support schemes and so to reduce the geographic trade and investment distortions they cause—and to find a way of preventing renewables distorting the energy market itself. So the challenge is one of both European market and energy market integration.

Renewable subsidies are particularly distortive because they are a) national and b) related to production. One reason why they are national is that renewables are part of member states' energy mix, which is still formally a national prerogative. Another reason is that some national renewable programmes long pre-date EU involvement in this area, as shown in **Figure 4.3**.

As part of the 2009 energy and climate package, it was decided to give member states different renewable targets for 2020 to take account of their differing natural endowment (sources of hydropower or exposure to sun and wind) and their differing levels of wealth (relevant due to renewables costing more than fossil fuels). The European Commission had twice before (2001 and 2007) proposed a pan-European subsidy scheme through the

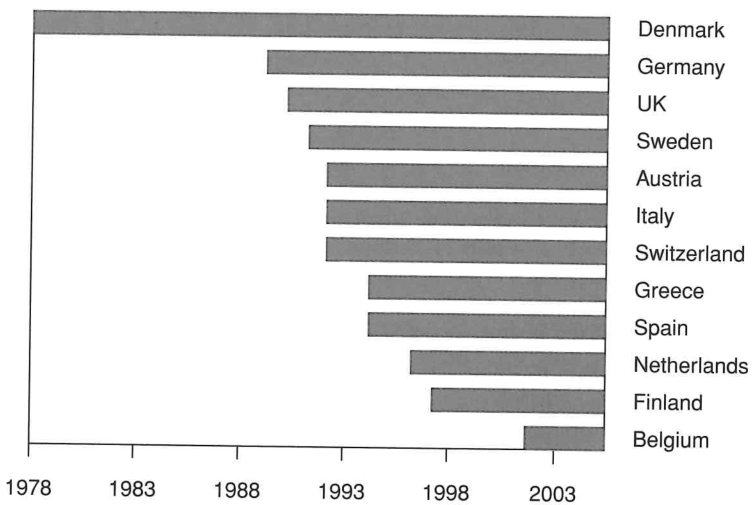

Figure 4.3: Some national renewable support schemes go back a long way

Source: Council of European Energy Regulators consultation on renewable energy support (2011)

trading of green energy certificates, but was on both occasions rebuffed by the Council of Ministers and the European Parliament, where cross-border trading of certificates was regarded as harmonization by the backdoor. So the 2009 package offered only two options for cross-border trading of renewables, both of them under the control of national governments. One is for two or more governments to create a joint subsidy scheme, which only Sweden and Norway have done so far. The other option is for one government to sell a 'statistical transfer' of some of its renewable energy to another government which would be buying the right to count this foreign percentage of renewable energy towards its own national target. No such deals have been done, though they might happen as the 2020 target date approaches.

In every other sector of the European economy, the European Commission hates operating subsidies related to production because they very directly distort the market. Even in agriculture, the EU no longer subsidizes farmers according to their output. Logically, the obvious way to support renewable projects, whose capital costs are far higher than their operating costs, would be with investment tax credits. This was in fact the norm in the early days of renewables, and a few countries still give income, corporate, property, or value added tax exemptions for renewables. However, once it was agreed that climate policy needed to produce specific outcomes (percentage cuts in emissions, percentage increases in renewable deployment), then it was decided that production or operating subsidies were the way to go.

The most popular variant of these production subsidies became the Feed-in Tariff (FiT), which guarantees the renewable project developer, over many years, a fixed payment that covers his costs and pays him a profit for production, regardless of prices and conditions prevailing in the electricity market. Indeed, the more unrelated these FiTs are to the market, and therefore the more they remove market risk, the more successful they have been in encouraging deployment of renewables. The evolution of Germany's FiTs is a case in point. Germany introduced a FiT scheme in 1991 which gave wind and solar producers only 80 per cent, not 100 per cent, of the retail power price, and therefore renewable generators needed to pay some attention to market conditions. Because this system retained some market risk for investors, the installation of new renewable capacity in Germany remained slow through the 1990s. In 2000, Germany moved its subsidy system right away from the market by offering fixed FiTs for every renewable technology and removing all price uncertainty for investors. As a result, renewable deployment has soared there, but so have the costs. In order to contain these costs, there have been recent moves in Germany and elsewhere to require renewable producers to get some of their revenue from the market and to subject them to the same market disciplines (such as paying for forecasting errors that put the market out of balance) as sellers of conventional energy.

For the past two years, the Commission has been playing catch-up by emphasizing the cost-effectiveness of a more European approach to these ballooning national renewable subsidies and their knock-on financial effect on conventional forms of electricity generation (see next section on capacity mechanisms). In a 2013 communication, 'Delivering the internal electricity market and making the most of public intervention', the Commission warned that national renewable (and capacity) support schemes were segmenting the European power sector (COM 2013). It delivered the message that national governments could save their own citizens money, and also render the cause of European integration a service, by tailoring subsidies more closely to market conditions and by harmonizing at least the structure, if not the level, of their subsidy schemes. The Commission followed this in spring 2014 with a new set of state aid guidelines (Guidelines 2014), exploiting its power to control the state aid that national governments give to their companies. In a formal sense, renewable subsidies are almost always paid by energy consumers as a levy on their electricity bills, rather than by taxpayers or by national treasuries. However, since these levies on consumers are organized and required by governments, they generally count as state aid.

The main features of the 2014 guidelines for new renewable projects require that:

- From 2016, in new renewable schemes, pure Feed-in Tariffs should be replaced by market premiums which provide renewable generators with a top-up of the price they can get in the market for their electricity, or by renewable certificate schemes which also act as a top-up of the market price. The idea is to incentivize renewable producers to pay attention to market conditions in order to maximize their earnings from the market.
- Also from 2016, renewable generators need to be responsible for selling their own electricity into the market (rather than leaving the transmission system operators to market their electricity, as happens in some countries at present). All governments must also make their renewable producers responsible for balancing and correcting or paying for any imbalance their power may cause on the grid. The idea is to encourage renewable generators to forecast their power deliveries as accurately as they can.
- From 2017, governments must start making renewable project developers compete for new subsidy money at auction. They are to hold tenders inviting developers to supply set quantities of new renewable capacity, and subsidy approval will go to those developers who commit to supply this capacity at least cost.

In its 2015 Energy Union plan, the Commission expressed the hope that these guidelines will 'limit the detrimental effects of badly-designed, fragmented and uncoordinated public interventions'. It said that 'effective application of this guidance can only be a first step to ensure that divergent national market arrangements...become more compatible with the internal market' (COM 2015a: 10). In its July 2015 electricity market design proposal, the Commission suggested the 'second step' should be regional coordination of national support schemes:

> A more coordinated regional approach to renewable energy – including support schemes – could deliver considerable gains, among others by promoting cost-efficient development of renewable generation in optimal geographic locations. This would enlarge the market for renewable energies, facilitate their integration and promote their most efficient use. (COM 2015c: 7–8)

However, the Commission conceded that 'while member states are becoming increasingly open to enhanced regional cooperation, practical difficulties remain'. The chief difficulty is fundamental, because it is about money. Governments are still very resistant to anything that might involve their consumers subsidizing renewables in other member states, unless they make a specific intergovernmental agreement to do so (which almost none of them have). Moreover, this resistance has recently been given legal backing by the European Court of Justice (see the Ålands Vindkraft ruling in Chapter 5).

Supporting conventional generation. The issue of capacity mechanisms arises out of the impact of renewable energy on conventional generation. Intermittent renewable energy has the effect of making all other sources of generation intermittent too. This undermines the traditional economics of conventional generation such as gas- and coal-fired power, which are needed, at least for the foreseeable future, as back-up for renewables. The relentless building of subsidized renewables, such as wind and solar power, produces complicated results. On the one hand, it tends to accentuate conventional overcapacity where it exists already (across much of Southern Europe and, at least locally, in Germany) and where gas and coal generating plants are often mothballed rather than shut down, or where the increase in renewable capacity outpaces the permanent retirement of conventional plants. On the other hand, it can make conventional undercapacity harder to remedy where it is pre-existing (as in the UK and Belgium) because investors are unwilling to build new conventional plants in markets with power prices depressed by the increase in renewables.

While there is no one-size-fits-all solution to these different situations around Europe, the answer that most EU countries are moving towards is some form of capacity payment to investors to keep conventional plants available to generate when renewable output falls short of demand. The following chapters discuss whether such capacity payments will be just a temporary solution, as part of an energy market that relies increasingly on flexible demand to match intermittent supply, or become a permanent part of a new market design.

To appreciate the changes wrought by renewables, it is important to understand how renewables fit into the 'merit

order', or the traditional line-up in which grid operators call upon generators to supply power. This dispatching system starts with the source of power with the lowest operating costs—and renewables are the cheapest because they have virtually zero marginal or running costs—and moves to the most expensive source with the highest marginal cost (likely to be gas or coal) until all demand is satisfied. The way this works financially is that the marginal cost of the last unit of power supplied sets the price for everyone. So, up to now, the most expensive source with the highest marginal cost (likely to be gas or coal) has been able to cover its higher fuel cost, while the cheaper generation sources with low marginal costs (wind, solar, nuclear) should be able to make enough money to cover at least some of their capital costs if they are receiving prices that reflect the high fuel costs of conventional sources.

Nowadays, however, with the surge of renewables onto the grid, the 'first' in the merit order can sometimes also be the 'last'. At times of high wind and solar generation, renewables can supply the entire demand and greatly reduce the opportunity for gas or coal plants to earn any money. This sort of problem has already occurred in some countries, particularly Spain, and is only likely to become more common. The effects are already being felt. The average utilization rate of thermal (gas and coal) plants fell from 50 per cent in 2008 to 37 per cent by 2013. If plants can only operate a couple of hundred hours a year, this might not matter to their owners, provided they could capture the very high peak prices which a free market would produce during these hours. However, investors suspect, probably rightly, that politicians would not dare risk such peak prices upsetting voters and that they would, in the event of real scarcity, put a cap on prices. This would give rise to what the energy industry calls 'the missing money' scenario, which describes an inability to recoup, on rare occasions of scarcity, the losses made during more normal operating conditions. It is not a scenario conducive to new investment. In order to improve the climate for investment, as well as for energy security, Germany persuaded 11 neighbouring countries to join it in signing a declaration in June 2015 to the effect that their governments would give market price signals free rein, allow price peaks, and refrain from capping power prices (BMWi 2015).

The International Energy Agency has illustrated the evolution of the plight for conventional generators with some numbers (IEA 2014c). In the years from 2000 to 2008, electricity demand rose 11 per cent and electricity producers installed an extra 15 per cent in total capacity (renewable and conventional). But demand fell away after the financial crisis of 2008 and the onset of the Eurozone debt problems, leading to a 3 per cent drop in electricity consumption 2008–12. Regardless of this decline, renewable capacity increased by 50 per cent over the same period, while the generating capacity of fossil fuel plants dropped by 14 per cent. Europe's major utilities, whose generating portfolio is still far more conventional than renewable, found their operating costs rising, partly due to the increased wear-and-tear on conventional plants required to start up and shut down more frequently in a mirror-like response to intermittent renewables. At the same time, these companies found themselves unable to cover these rising costs with prices depressed by the impact of renewables. As a result, the combined net income of the EU's 20 largest publicly listed utilities fell by 85 per cent between 2009 and 2013. New investment is not at a total standstill, but it is greatly reduced. According to Platts, the volume of combined-cycle gas turbine capacity under construction in September 2014 had fallen to less than 4 GW from a level of 11 GW two years earlier, while that of coal capacity being built was under 7 GW compared to 12.6 GW in autumn 2012 (Platts 2014).

Not surprisingly, there has been a general call from utility companies for some form of payment or compensation if they are to keep largely idled conventional plants available for occasional service as back-up power, and to offset the policy-induced hit to their traditional sources of revenue. This call has not fallen on deaf ears in national governments, which are keen to avoid any risk of the lights going off in their countries.

Capacity payments are not new. For many years, Nordic countries have paid their utilities to set aside a 'strategic reserve' of generation for use whenever insufficient rain or snowfall reduces the amount of hydroelectricity on which these countries depend. With the more recent advent of large volumes of wind and solar reaching their grids, a number of EU countries—chiefly the southern nations of Portugal, Spain, Italy and Greece, but also Ireland—instituted capacity payments to prevent a situation of growing overcapacity leading to wholesale closure of conventional capacity that is still needed to balance renewables.

However, the UK has led the way in developing a fully-fledged capacity market which will meet power shortfalls by reducing demand as well as increasing supply. In December 2014, the UK held its first capacity auction with generators bidding to be paid to guarantee power supply for the winter of 2018–19, with providers of demand response expected to bid in a second auction to be held nearer the time. (There is a natural timing discrepancy between suppliers, who may need considerable advance notice to prepare to carry out supply guarantees, and providers of demand response, who may be unable to gauge many months or years in advance what demand reduction they can offer.) The UK initiative came about less because of the impact of renewables, still a relatively small proportion of UK electricity, and more because the UK faces an impending gap in overall capacity. Due to years of delay and dither about new nuclear plants, and to the decision of several of its energy companies to respond to new EU environmental restrictions by shutting down coal plants rather than cleaning them up, the UK confronts the prospect that its maximum level of generation will barely meet peak demand after taking account of the expected level of plant availability. The reserve margin on the UK grid is expected to fall to a dangerously low 4 per cent in 2016–17. Due partly to a phase-out of its nuclear sector, Belgium also faces an overall capacity gap, and is designing a capacity mechanism to assist.

France is also creating a capacity market, to take first effect in the winter of 2016–17, mainly to solve a problem of meeting peak demand which, for the moment, is unique to that country but which will become more widespread with decarbonization. Reliance on nuclear power to generate more than 70 per cent of its power supply has greatly reduced French carbon emissions. France has pursued decarbonization by extending the use of this near zero-carbon electricity to heating, cooling and, to some extent, transport. The French economy is thus more electrified than elsewhere in the EU, but this also makes its power system more sensitive to changes in temperature. The rule of thumb for France's grid operators is that every one degree Celsius drop in temperature adds an extra 2.3 GW to electricity demand (roughly 3 per cent of recent peak demand), or almost half the total temperature sensitivity of power demand in the whole of the EU. The 2013–14 and 2014–15 winters were mild in France, but for the previous 11 years the annual peaks in demand had increased steadily year on year, from 75 GW in 2001 to 102 GW in 2012. This 2012 peak in demand briefly turned France, which is normally Europe's biggest exporter of electricity, into an importer of power from all available sources. It also led to preparations for a French capacity market. France has gone furthest in reducing emissions, by first decarbonizing the power system and then extending its use, but other EU countries are pursuing the same strategy. This decarbonization policy is logical, but it can create strains on the power system that capacity markets can help ease.

While France, the UK, and some Eastern European member states have installed generation capacity that is not far above their average peak demand levels, an increasing number of countries have generation assets with a formal nameplate capacity that is more than twice their peak demand, as shown (**Table 4.3**) in the case of Germany, Italy, and Spain.

Table 4.3: Installed capacity vs peak demand

	France	*Germany*	*Italy*	*Poland*	*Spain*	*UK*
Installed generation capacity (GW)	131.3	171.6	124.2	34.5	102.8	84.9
Peak demand (GW)	102.0	81.8	54.1	23.9	43.5	56.2

Source: European Commission, 2011–2013 in EU Energy Markets in 2014

These three countries have installed quite enough generation capacity to meet all demand needs, but they can only rely on renewable generation producing a fraction of its maximum nameplate capacity. Moreover, as they increase the share of intermittent wind and solar power in their generation portfolio, all EU states will experience a correspondingly diminishing share of flexible, controllable generation (fossil fuels, nuclear, and the controllable renewable sources of biomass and hydroelectricity) that can be stopped and started to cover the peaks and troughs in intermittent renewable output.

Nonetheless, some governments are not yet convinced that they need a fully-fledged system of capacity support. The most important of these is Germany, where the two leaders of the coalition government, Chancellor Angela Merkel and Vice-Chancellor Sigmar Gabriel, have complained publicly that the electricity companies are playing up the threat of blackouts simply in order to get another subsidy, which would be another burden on German consumers already paying a high price to support renewables. Germany's capacity problem is also more local than national, due to the lack of sufficient transmission lines to carry excess wind power in the north to centres of industrial demand in the south. For the moment, Germany is managing to cope with the consequences of renewables surging intermittently onto its grid, largely through the legal ability of its national energy regulator to order certain conventional generators to stay online in the interest of grid stability, and partly through the improved ability of the country's coal and nuclear operators to ramp output up and down in response to the supply from renewables. However, the issue of a fully-fledged capacity market, including an element of demand response, is under consideration in Germany.

The European Commission has made no secret of its dislike for national capacity schemes for several reasons. It claims such subsidies risk distorting energy investment and trade, that they would increase wholesale energy prices, and that, worst of all, they would once more carve up the internal energy market along national lines and undo the Commission's integration and liberalization efforts. The Commission message has been that member states should only consider national capacity schemes as a last resort. Governments should first check whether the causes for inadequate generation are the result of their own bad policies, such as regulated prices that deter companies from investing, or whether demand response might provide a solution. Only after examining and exhausting these alternatives should governments set up a national capacity scheme, and even then the scheme should take account of the back-up power that neighbouring countries could provide.

Generally, the Commission has the means to enforce its view on capacity mechanisms, which are considered a form of state aid that the Commission has a treaty power to control or veto if they are deemed distorting to competition. (It is possible some capacity payments might escape state aid scrutiny by the competition directorate in Brussels—if the payments are structured or characterized as compensation for a public service obligation, rather than as a subsidy.) The first major decision on 'allowable' capacity schemes came in July 2014, when the Commission approved the UK's new Capacity Market plan. It signalled its satisfaction on two particular points: that the UK had committed itself to letting foreign suppliers participate in the capacity auctions, and that these auctions would be open to providers of demand reduction as well as of supply increase.

Both these points are difficult. Regional capacity schemes, or national schemes coordinated on a regional basis, make eminent sense, but if regional capacity schemes require dedicated cross-border transmission which is subtracted from the commercial market, then the mechanism of market coupling, described in the first part of this chapter, will be obstructed. Likewise, inclusion of demand response, laudable in itself, raises a number of questions. Can demand reduction be as reliable as provision of supply in view of the fact that demand response aggregators will not actually own the assets whose demand is being reduced? How would one classify on-site generation—is it generation, potential demand reduction, or both? Perhaps most important of all, any capacity market that includes demand-side response will have to deal with low-voltage distribution networks as well as the high-voltage network. These and other wider issues are addressed in subsequent chapters.

Nonetheless, the Commission is finally grasping the nettle of capacity mechanisms. In April 2015, its competition directorate launched a broad-ranging investigation, known as a 'sector inquiry', into the plans of 11 EU states—Belgium, Croatia, Denmark, France, Germany, Ireland, Italy, Poland, Portugal, Spain, and Sweden—proposing to introduce some form of

capacity mechanism. (The UK is not included because the Commission has already approved its capacity scheme.) One aim of the sector inquiry is simply to gather information about what precisely these states plan, but it also has other clear motives: to warn these member states to respect state aid rules as they go about designing and implementing capacity mechanisms; and to slow down the process while the Commission comes to a considered view about those bad design features of capacity mechanisms that distort competition and cross-border trade, and those good features that could complement the internal energy market rather than divide it. The Commission's goal is that the findings of this inquiry should feed into reform of Europe's electricity market design, perhaps in the form of new legislation in 2016.

As a pre-condition to any capacity scheme, the Commission would like to see the member states reach some assessment, preferably on a regional basis, of what their generation adequacy (or inadequacy) problem really is before attempting solutions. Predictably, it is the members of the so-called Pentalateral Energy Forum which are leading the way in this, as they did with market coupling. In March 2015, the TSOs of the original pentalateral five—France, Germany, and the three Benelux countries—plus Austria and Switzerland published the first common regional adequacy assessment in Europe. The results were nothing extraordinary: France and Belgium were the only countries identified as having a possible short-term problem due to closures of gas-fired plants. However, the main achievement appeared to be the methodology of how to carry out complex, probabilistic assessments of future power supply and demand balances for multiple countries. This is likely to be the model that ENTSOE will promote for an assessment of generation adequacy in the EU as a whole.

Germany, as with so much in today's European Union, was the prime mover in this regional approach to generation adequacy. Berlin followed this up in June 2015 with the code of good conduct declaration, signed by 11 other countries ranging from Norway to the Czech Republic and which also included pledges to refrain from restricting cross-border electricity trade even in times of scarcity. This initiative looks very much like an eleventh-hour attempt to preserve as much of the traditional energy-only market as possible, and not surprisingly it has strong Commission support. However, it is unlikely to head off the need for fundamental redesign of the electricity market, as the following chapters will show.