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Why Europe's energy and climate policies are coming apart*

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1. Introductory summary

The European Union is the only major region of the world that has seriously tried to integrate its energy and climate policies. Reflecting the fact that, in terms of a global average, the burning of fossil fuels accounts for two-thirds of all man-made greenhouse gases, the EU has made emissions reduction a very significant goal of its energy policy, while still retaining the more traditional aim of ensuring supplies of secure and affordable energy. It has promoted low-carbon energy supply, and pursued energy efficiency policies to curb energy demand and therefore emissions. Initially, energy and climate policies were legislated separately. In the late 1990s, the EU started to pass reforms – in the hope of creating a single market in energy – while in the early 2000s it began to set indicative renewable energy targets for its member states. Then in 2005 the EU established the Emissions Trading System (ETS), a pan-European climate instrument whose coverage encompassed all major electricity generators. Energy and climate policies were further bolted together in the energy and climate package of legislation that was proposed in 2007, negotiated in 2008, and approved in 2009. The energy part of this package was the Third Package of reforms to trading arrangements and regulatory governance of the single market, while the climate part comprised a revamp of the ETS, mandatory targets for renewable energy, and a softer target for energy efficiency. Climate and energy policies need to go together. Climate policy really is synonymous with energy policy; agriculture is the only other sector producing major amounts of man-made greenhouse gases, but drastic action here would involve an end to ploughing (which releases carbon from the soil) or to keeping livestock (which generates methane).

But, after what looked in 2009 like a plausible marriage between climate and energy policy, divorce is now in the air. Recession has made Europe's governments, industry, and consumers neurotic about high energy prices – which many blame on expensive renewables. Bulgaria recently lost a government to protests about electricity prices; Spain has broken contracts with renewable energy producers in order to scale back its commitments to them; and German industry is obsessed about losing export competitiveness because of energy costs. The main complaint is about the surge in subsidies on renewables. The complainers make the contrast with the USA, which they say has refused to saddle itself with a burdensome climate policy and which is also reaping the benefit of shale gas, driving down both its gas and electricity costs.

Few complain about the cost of the ETS, because it has not actually brought about any real costs; recession has rendered it useless as a financial instrument for promoting low-carbon generation and curbing high carbon consumption. Yet few rush to fix the ETS, lest a repaired ETS impose a cost that would be unwelcome in times of recession. Günther Oettinger, the EU energy commissioner, argues that Europe can no longer afford to subordinate energy policy to a unilateral climate policy. 'We cannot be the good guys for the whole world, when no one is following us', he told a Brussels conference at the end of May 2013.

However, the growing tension between energy and climate policies is not just the result of recession – a cyclical factor. The Commission's energy directorate has become increasingly worried that climate-related policies – in other words national subsidies for renewables and for back-up generation capacity (needed for intermittent renewables) – are throwing up structural obstacles in the pathway to a pan-European market. These national subsidy schemes serve national interests and priorities, not surprisingly. National subsidies for renewable energy are designed to help national renewable generators meet national renewable targets; this distorts investment patterns within the single market. National capacity schemes reserve national spare capacity for national needs, in contravention of normal free trade within the single market.

But the objection of the Commission's energy directorate to national subsidies is not just that they are national; the Commission had to concede national subsidies for renewable energy when it failed twice in the 2000s to convince the Council of Ministers and the Parliament of the merits of a pan-European renewable subsidy scheme which would have involved green electricity certificates being traded across borders, in the same way as ETS allowances. The Commission's other objection to these national schemes is that they introduce a degree of state intervention into the marketplace that undermines the liberalization considered necessary to achieve the single market.

As a result, the Commission is undertaking what it sees as a damage limitation exercise by producing guidelines that, among other goals, seek to Europeanize, or at least regionalize, national renewable and capacity subsidies. The guidelines, expected during the summer of 2013, will urge member states to harmonize, or even merge,

support schemes for renewables, perhaps on a regional basis, and to allow energy companies from other member states to participate in capacity schemes.

However, these recommendations assume rapid progress in completing the framework for the single market – in terms of building more cross-border interconnectors, harmonizing trading arrangements, and agreeing on network codes in electricity and gas. In 2011 EU leaders said this work should be completed by 2014, as part of their public commitment to having 'a fully functioning, interconnected and integrated internal energy market' by that date. This work is proceeding. The Commission wants, in particular, to achieve maximum progress towards a pan-European energy network, so as to give individual member states minimal excuse to design autarkic national renewable and capacity schemes. But building infrastructure takes a long time and harmonizing trading arrangements is a complex business; it is clear the work will only be half finished in 2014.

Some member states might therefore be tempted to ignore these guidelines, and if so the Commission might eventually be tempted to use its state aid control powers in an attempt to enforce aspects of the guidelines. This would be the wrong way to tackle the growing contradiction between energy market liberalization and climate-related public intervention for all concerned. The Commission needs to produce a serious re-think of how to accommodate these conflicting goals, and governments need to give the matter serious consideration. Unless the EU abandons its climate policy, which is still unlikely, the problem will not go away. Both renewable energy and back-up generating capacity may need subsidizing on a permanent basis.

2. Recession and other cyclical tensions between energy and climate policies

The two cyclical factors creating strain between Europe's energy and climate policies are the economic downturn and the failure of the rest of the world to follow Europe's unilateral lead on climate policy. These factors will not last forever – which is why they can be described as cyclical – but they will last for some time. Austerity policies look like prolonging the eurozone debt crisis for several years to come. In 2015 the global climate negotiations are supposed to produce an agreement, which could bring the USA, China, and other major emitters more into line with the EU. However, it is already agreed that such an accord would not take effect until 2020.

Deepening recession and rising unemployment in large parts of Europe have increased public sensitivity about the price of energy, especially that of gas which in Europe is expensive to the extent that it is linked to the still-buoyant world price of oil. Much of the blame for high energy prices is attributed to climate policies in general, and to subsidies for renewables in particular. The volume of these subsidies is rising at least as fast as the level of renewable energy generation capacity, which is increasing each year in line with EU-agreed targets. Indeed, subsidies for renewables are rising faster than renewable generation capacity in some countries, for example the UK, which is pushing more expensive offshore wind generation capacity harder than cheaper onshore wind.

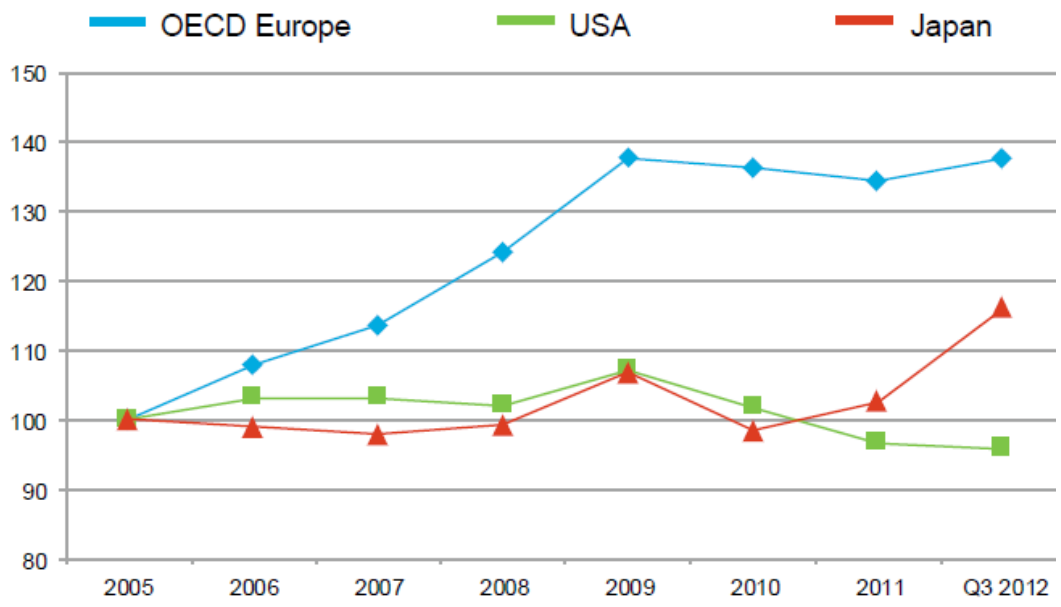
Prominent among those people arguing most strongly for EU energy policy to be decoupled from climate policy are Europe's industrialists. This is despite the fact that provision has been made at the EU level, and in most member states, to exempt energy-intensive sectors from some or all of the extra climate-related costs imposed on energy users. Intensive energy users judged to be particularly exposed to international competition can get free carbon allowances on the Emission Trading System, although this is currently a minor benefit given the low ETS price. In addition to this assistance, most EU governments, including the UK, have added tax breaks or cost exemptions. In Germany, where the clamour is loudest about the issue of Europe's energy costs undermining its competitiveness, energy-intensive companies pay a tiny fraction of the renewable energy surcharge that German households have to

pay. These companies are also exempted from electricity grid charges with, again, German households picking up the bill and cross-subsidizing industry.

However, the factor which is making much of European industry both anxious and jealous is the perceived benefits of the shale gas revolution in the USA. The European Commission noted with alarm in its March 2013 Green Paper on energy and climate policy that gas prices for industry were more than four times lower in the USA than in Europe. [1] The Green Paper cites IEA data that, for the 2005–12 period, real (discounting for inflation) electricity prices charged to industry rose by an average of 38 per cent in west European countries, while in the USA they decreased by 4 per cent, mostly because of lower gas generation costs.

Beguiling contrast with the USA in electricity (1)

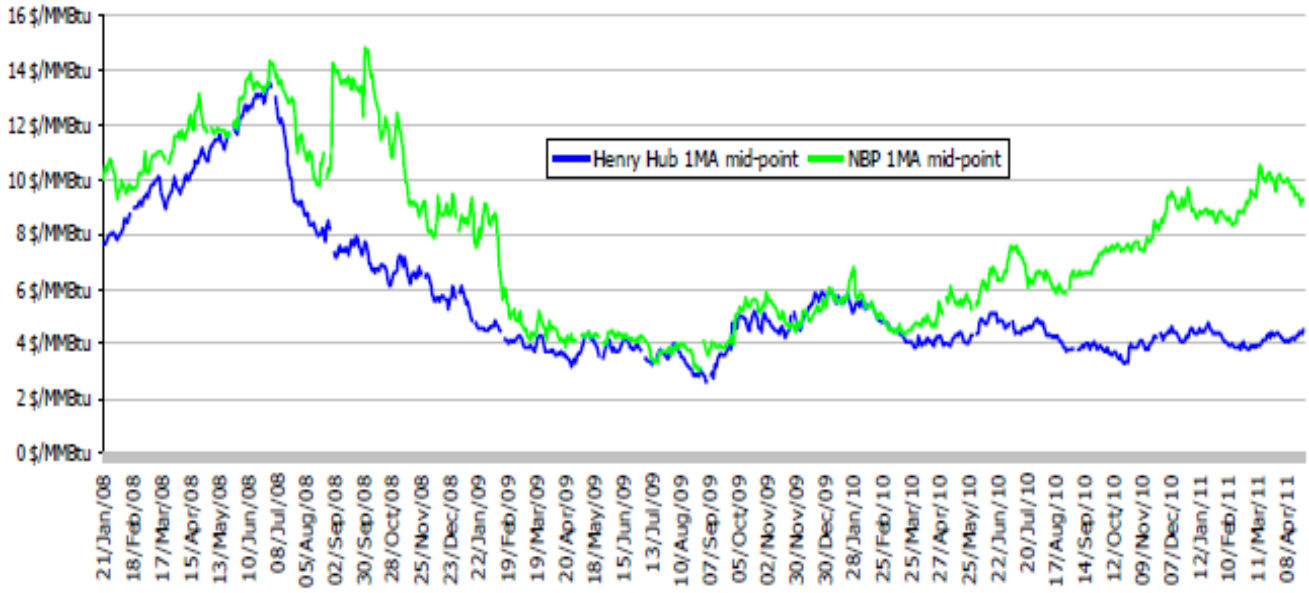
Figure 1: Evolution of end-user electricity prices for industry, taxes excluded (2005 = index 100)



Source: International Energy Agency.

Beguiling contrast with the USA in gas (2)

Figure 2: US and UK gas prices drift apart



Source: EU Joint Research Centre report on unconventional gas, 2012

It is not self-evident that cheap energy has always benefited the USA or other countries such as Russia, especially where the energy in question is fuel for appliances like cars. High or higher energy prices have driven efficiency in Europe and Japan and have helped them sell products all around the world. Countries can adjust to higher energy prices, shedding jobs in sectors where energy is a significant raw material input, and gaining jobs in sectors producing energy-efficient appliances and services. But there is no escaping the fact that European industries such as aluminium, chemicals, and petrochemicals face a real worry about losing jobs and market share to the USA. Gas accounts for 35 per cent of the energy used by Europe's chemical industry, and gas can represent 60–80 per cent of the cost of fertilizer. Since 2008 Europe has lost 2m tonnes of aluminium production a year, while global production has expanded by 10m tonnes a year, mainly in the Middle East and Asia.

But Europe cannot do much to close the current gas price gap. It might be able to buy gas in the USA cheaply, but the cost advantage could not survive the journey across the Atlantic, once the costs of liquefying, shipping, and re-gasifying the gas are taken into account. Europe might of course accelerate development of its own shale gas, and this is indeed what Poland, some other central European states, and the UK are trying

to do. But the consensus forecast is that shale gas production costs in Europe will be more than double those in the USA, because, compared to the USA, Europe's shale layers are deeper, its regulations may be tighter, and its oil and gas service less competitive [2]. Moreover, no substantial shale gas production is expected in Europe until after 2020.

Europe should not panic about its gas and electricity price divergences with the USA, partly because the differential may be temporary (certainly so, if the US government allows gas exports that will cause domestic prices to rise), and partly because there is not much Europe can do to close the price gap. But the US shale gas revolution partially undermined the assumption of rising fossil fuel prices on which Europe's energy and climate package was negotiated in 2007–8 and signed into law in 2009. This is important because the higher the price of fossil fuels, the lower the real net cost of replacing them with renewables. This was part of the European Commission's sales pitch for the 2009 package (and the argument was also used by the UK government for its national version of an integrated energy and climate policy). The assumption was understandable – the oil price had risen steadily and strongly throughout the 2000–8 period – and not totally mistaken. After a spectacularly quick collapse and bounce-back in 2008, the oil price has stabilized at around $100 a barrel.

But Europe's policy makers have been wrong-footed by the impact of shale development, which few in Europe had heard about in 2007–8, on the domestic US gas price. This has, in a sense, 're-regionalized' the US gas market price. Just as it had begun to seem that gas pricing in the US market was about to join the rest of the gas world, through imports of LNG, shale development suddenly put the USA back on its own separate planet of much cheaper gas prices. Direct exposure to competition from cheaper US energy is, furthermore, all the more alarming to many European industrialists at a time when Brussels and Washington have committed themselves to attempts to negotiate a transatlantic free-trade zone.

Europe's 2009 policy package was also based on the hope that the Copenhagen summit at the end of that year would see the rest of the world copying Europe's ambitious lead in climate policy. That hope of a global climate treaty was dashed at Copenhagen. What remains is a vague commitment to reach, in 2015, some sort of agreement that would take effect in 2020. For many Europeans, their continent's

failure to get matching commitments from other countries goes halfway to undermining Europe's unilateral climate policy – and the process of undermining is completed by the irony that shale gas is reducing emissions in the USA while raising them in Europe's power generation – where increased amounts of US coal, displaced into Europe by shale gas at home, is being burnt.

3. Renewables and other structural factors driving energy and climate policies apart

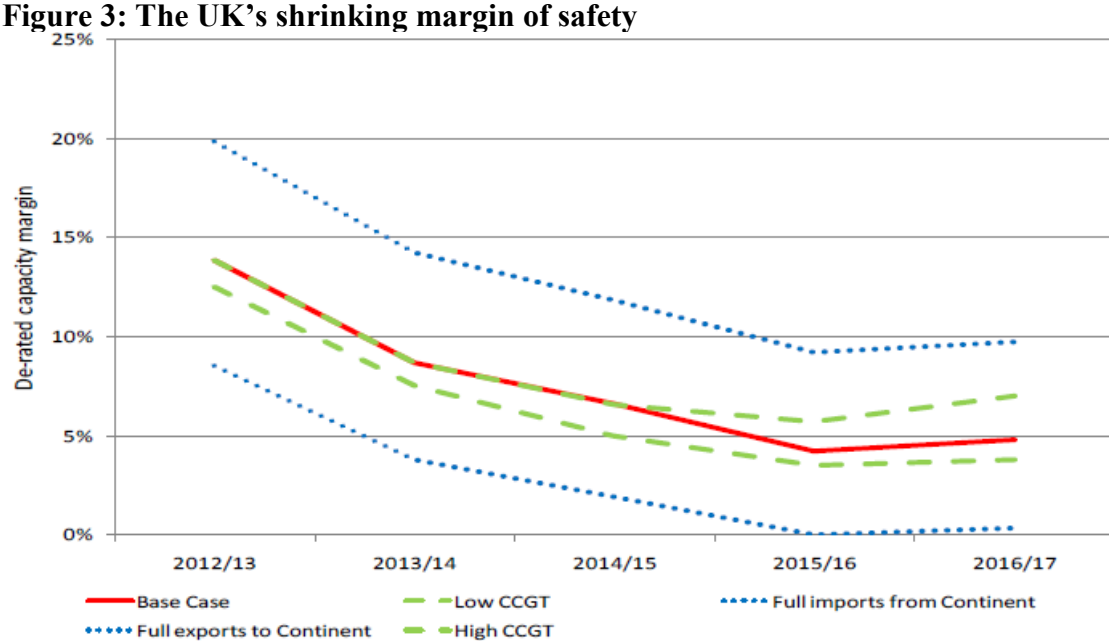
In addition to cyclical factors, structural changes are also increasing the tension between energy and climate policy in the EU's energy sector. These mostly relate to renewable energy: the way it has been supported through national subsidies, the consequent demand for national subsidies for back-up power generation and, as the European Commission sees it, the challenge that these national schemes pose to its conception of a single pan-European energy market that it has been trying to create for nearly 20 years. Here the tensions are as much inside the Commission as outside it – between those who are reluctant to let the development of renewables spoil the tidy symmetry of their single market blueprint, and those who accept that the single market must accommodate climate policy and, if necessary, change.

The 2009 energy and climate programme was the culmination of legislative efforts from the mid-1990s onwards to unify markets that had been originally designed as national monopolies to serve national interests and customers. It contained a final package of legislation to separate transmission systems from energy groups, in order to transform them into common carriers of energy across frontiers. It formalized European organizations of national energy regulators and transmission system operators (TSOs), giving them the tasks of coupling markets together and of agreeing network codes to harmonize trading arrangements across the EU (all of which is discussed later in the paper). But all this work of linking up markets and harmonizing trade arrangements is predicated on an 'energy only' market where the forces of supply and demand are supposed to create competitive, cost-reflective, and convergent prices, free of national barriers or aids.

However, in reality, the share of non-subsidized electricity is becoming a shrinking part of the total market because of the growing volume of renewables. There is also the prospect that national subsidies will be applied to a further slice of the market, in order to keep enough conventional, fossil-fuelled generators ready and willing to provide back-up for intermittent renewables, when the wind drops or the sky clouds over. In this way, subsidies could take over most of the electricity market, with little left of the 'energy only' market. As the Eurelectric industry association of Europe's main generators says, 'competitive markets cannot be a minor part of the market'.

The capacity issue can cover two somewhat different problems. The first is a lack of sufficient overall capacity in which, even if all of a country's power generators (renewable ones included) are generating at full capacity, there may still be a risk of the lights going out. The UK is a classic case of this position: due to the country's delay in replacing dirty coal plants and ageing nuclear reactors, this risk of an overall capacity shortage is growing. Figure 3 below shows the estimate from Ofgem, the UK regulator, of how the country's safety margin of reserve capacity (following the red line marking Ofgem's base case) will shrink from around 14 per cent of overall generation today to less than 5 per cent by 2015/16. This is a risk, even though the UK's overall capacity in 2015 will still include relatively few intermittent renewables flowing onto and off its grid.

Figure 3: The UK's shrinking margin of safety



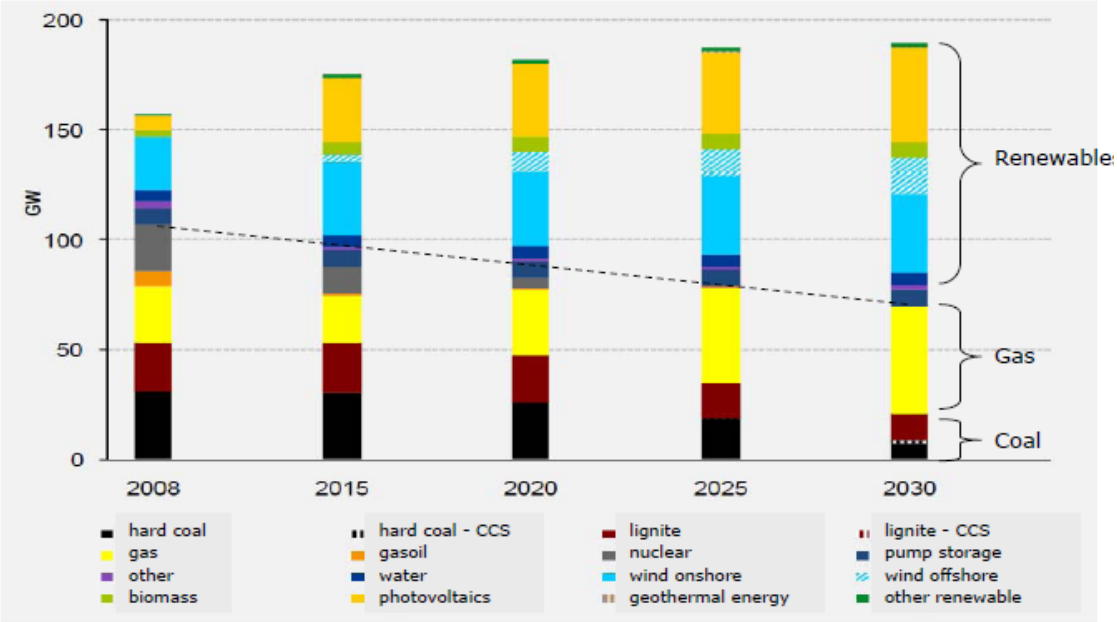
Source: Ofgem

The second is a problem which more EU states, and also the UK in the future, will face as renewables grow: a lack of appropriate capacity that is both fast and sufficiently flexible to back up intermittent renewables. This is Germany's challenge. The country still has considerable overall spare capacity left over from the gold-plated pre-liberalization era. The sudden shut down in 2011 of eight nuclear reactors with 8 gigawatts (GW) of capacity, at a stroke of Chancellor Merkel's pen, still left Germany with nearly 100 GW of generating capacity. This constitutes, for the moment, a comfortable reserve margin of at least 15 GW (or 15 per cent, roughly the current UK

margin), because peak load or peak demand is around 82–3GW. However, this demand is being met with an increasingly changeable supply mix. What Germany lacks is sufficient flexible conventional back-up to counterbalance the huge amount of wind and solar power coming on stream in Germany. Figure 4 below is a projection of Germany's energy mix in the light of its nuclear phase-out decision and its *energiewende* programme to expand renewables.

The expansion of installed capacity for renewables is shown above the dotted line in Figure 4. This is not at all the same as actual output because only a small percentage of total installed wind and solar capacity can be firmly relied on to produce at any time. The area below the dotted line shows what is available as installed conventional generating capacity – coal (hard coal and lignite), gas, and (until around 2022) some nuclear power. This is all firm capacity – in the sense that, unlike renewables, it can be switched on and off when needed (but only slowly in the case of nuclear, reasonably quickly in the case of coal, and very quickly only in the case of gas and pumped water storage). Figure 4 shows that, at least until 2020, the majority of Germany's conventional generating back-up, available to offset variations in renewables, will consist of its relatively inflexible coal and nuclear capacity.

Figure 4: Installed electricity generating capacity in Germany (GWs)



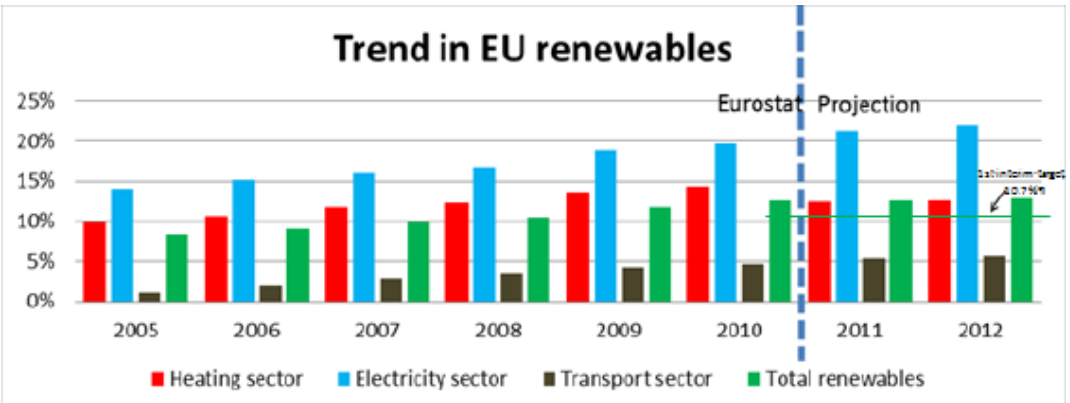
Source: Prognos; Energy Research Institute; Ministry of Economics

In its March 2013 *Renewable Energy Progress Report*, the Commission said the overall picture was of:

> … a generally solid initial start at EU level, but with slower than expected removal of key barriers to renewable energy growth and with additional efforts by particular member states necessary [3].

Table 5 below (taken from the *Renewable Energy Progress Report*) illustrates the solid start in the 2007–10 period, and the fact that, according to this Eurostat projection, it has stalled in the last two years.

Figure 5: Increasing penetration of green power



Source: *Renewable Energy Progress Report*.

The situation by 2010 was not looking too bad even if, on the road to the binding targets of 2020, half the EU membership had not met their indicative goals for 2010 in renewable electricity, and three-quarters had failed to meet indicative goals in renewable transport. However, as regards technology, the actual deployment of offshore wind has been falling well behind the levels set out in the national renewable plans that member states file to Brussels. Onshore wind and biomass are also lagging. By contrast, in what has been called 'the solar surprise', the installation of solar PV capacity has outstripped expectations, though this has also led to disruptive cuts in subsidies. As a result, renewables are penetrating the electricity sector faster than other sectors (see Figure 5). This is line with Europe's overall strategy of first de-carbonizing its electricity supply and then further electrifying the wider economy.

In the first quarter of 2013, however, investment in renewables fell by 25 per cent across Europe and came to a standstill in certain countries such as Spain. Analysis carried out for the Commission [3] casts some doubt on the sustainability of renewable energy expansion, because of administrative and infrastructure obstacles

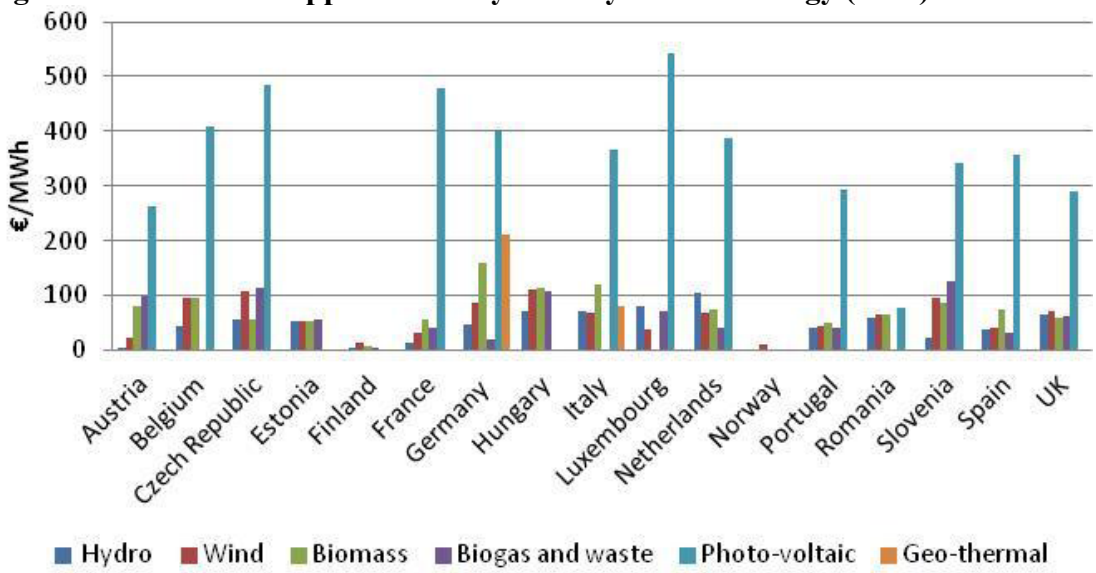
and disruptive changes to support schemes. Barriers to renewables are still widespread. Administrative procedures are still complex; only three countries – Denmark, Italy, and the Netherlands – have a single permitting system for the building of renewable generation projects. Once built, renewable projects often find it difficult to get the necessary connection to the low-voltage grid. Such grid connection problems for renewables usually occur within a member state and thus the new EU regulation on infrastructure (see Section 4) is not of much help. This regulation streamlines planning procedures for a selected number of priority high-voltage power lines and high-pressure gas pipelines across borders.

The other constraint on the growth of renewables is the growing criticism of the cost of subsidizing them. The nominal cost is very high (the real net cost to an economy also depends on the costs of the fuels replaced by renewables). The latest official figures, provided by the Council for European Energy Regulators (CEER) are for 2010, and cover only 17 EU member states (although all the larger ones are included) [4]. According to the CEER survey, the 17 countries spent a total of Euros 25.2bn supporting renewable electricity. Nearly 40 per cent (Euros 9.5bn) of this was in Germany, while the second largest subsidizer was Spain with Euros 5.3bn spent in supporting green power. Spain was spending much more than the larger states of Italy, France, and the UK because its share of renewables in electricity generation was much higher (20 per cent in 2011) than that of Italy (10.0 per cent), France (3 per cent), and the UK (5.7 per cent).

Today, these subsidy figures will be different. Germany's renewables support spending is even higher. A 47 per cent increase in its 2013 consumer levy to pay for renewables could bring Germany's subsidy [in 2013] to around Euros 20bn, though the Merkel government is trying to trim this. Meanwhile, Spain might now be spending less on support for renewables. Madrid is certainly trying to spend less. In 2012 it suspended negotiations on any new projects and in 2010 Spain placed an annual limit on the number of hours it was prepared to pay existing renewable electricity producers. This limit shook investor confidence because its imposition on existing producers appeared to be a breach of contract. Spain has not been alone in taking retroactive measures to cut subsidies, the Czech Republic and Bulgaria have also done so.

Much of the disruption has been in solar PV schemes. Solar PV merits a fairly high level of support, because of its potential as a decentralized power source in cities and crowded spaces. Figure 6 below shows how far solar PV subsidy levels have outpaced support for other renewables. In 2010, for instance, solar PV in the Czech Republic was being subsidized to the tune of Euros 496 per megawatt hour. Such a rate was far too high, given the sharp fall in the cost of buying Chinese PV panels, and given that PV investment is particularly reactive to subsidy incentives. Where PV subsidies are generous, the relative ease of installing solar PV can cause a sudden surge in solar generation capacity, outstripping infrastructure and giving rise to windfall profits for operators. (The windfall profit margins for European solar PV developers may have been boosted by the Chinese dumping solar panels on the EU market at a sales price below their cost of production in China, as has been alleged by the European Commission.) Therefore politicians and regulators have been scrambling to cut PV tariffs, leading to a boom and bust in several countries in a way that has disillusioned public opinion in relation to renewables, dislocated supply chains, and discouraged future investment.

Figure 6: Renewable support levels by country and technology (2011)



Source: CEER 2013

As Marie Donnelly, the Commission official in charge of renewables, told a conference in January 2013:

> I am not sure we are going to make our 2020 targets. We cannot afford to be complacent, because the trajectory [to meet the target] should go up sharply nearer 2020 [5].

This trajectory allowed member states seven years, up to 2012, to achieve the first 20 per cent of the target. However, in each subsequent two-year period up to 2020 it steadily raises the bar, so that in 2019–20, member states are supposed to achieve no less than 35 per cent of their total goal.

The integration challenge posed by renewables is to reduce the differences between the 27 national schemes, and thus to reduce the trade and investment distortions they cause – and to do so in a way that meshes renewables into the energy market more successfully. So the challenge is to both European market and energy market integration.

Support schemes for renewables are national for a variety of reasons: because renewables are part of a member state's energy mix, which is still formally a national prerogative; because national renewables programmes long pre-date EU involvement in this area; and because member states have been given different targets for renewables. And because governments have different targets, they insist that they need to have control over the subsidy schemes used to meet these targets. Faced with the level of attachment to national subsidy schemes felt by governments, their national renewable energy lobbies, and their supporters in the European Parliament, the Commission confined itself, in the 2009 energy and climate package, to trying to reduce the differences in subsidy levels by encouraging cross-border trade in renewable energy or certificates of renewable energy. The Commission twice (in 2001 and 2007) proposed pan-European trading of green energy certificates, and twice it was rebuffed by the Council of Ministers and the European Parliament, which have regarded cross-border trading as EU harmonization-by-the-backdoor (which it could be). At present, the only cross-border trading of renewables which is officially recognized and encouraged is between consenting governments in order to meet their targets. (And even some of this cross-border trading could be virtual rather than actual, with one government selling a 'statistical transfer' of some of its renewable energy to another government that would be buying the right to count this foreign percentage of renewable energy towards its national target.)

The Commission is expected to propose guidelines for national support schemes (alongside guidelines on capacity markets). These will address three main issues. First, the issue of cost control. The guidelines will stress the need for support tariffs to

be adjusted transparently, regularly, and quickly so as to keep pace with falling technology costs, as frequently did not happen with solar PV schemes. They will warn that retroactive subsidy-cutting damages investor confidence. The guidelines may seek to establish a benchmark of renewable technology costs that member states can use as a basis for setting subsidy levels.

Second, the issue of energy market integration. The guidelines will suggest that producers of renewable energy need to be more exposed to market prices and disciplines, in the same way as conventional power producers. Feed-in tariffs – which provide renewables producers with a fixed subsidy covering all their costs, together with a mark-up – are now considered less useful than premiums that just top up whatever revenue a producer of renewable energy can get from the regular energy market. As to market discipline, renewables producers should be made responsible for the imbalances that their erratic solar or wind power deliveries can cause. This already happens in Spain, for example.

Finally, the issue of European market integration. Member states will be urged to trade and cooperate more on joint renewables projects, as set out in the 2009 renewables directive. Neighbouring countries should also be encouraged to harmonize or merge their support schemes, on the basis of regions that might coincide with areas where regulators and TSOs are coupling markets and harmonizing trade arrangements.

Table 1: Member states' progress – renewable shares in total energy consumption

Member State	2005 RES share	2010 RES share	1st interim target	2020 RES target
Austria	23.3%	30.1%	25.4%	34%
Belgium	2.2%	5.4%	4.4%	13%
Bulgaria	9.4%	13.8%	10.7%	16%
Cyprus	2.9%	5.7%	4.9%	13%
Czech Republic	6.1%	9.4%	7.5%	13%
Germany	5.8%	11.0%	8.2%	18%
Denmark	17%	22.2%	19.6%	30%
Estonia	18%	24.3%	19.4%	25%
Greece	6.9%	9.7%	9.1%	18%
Spain	8.7%	13.8%	10.9%	20%
Finland	28.5%	33%	30.4%	38%
France	10.3%	13.5%	12.8%	23%
Hungary	4.3%	8.8%	6.0%	13%
Ireland	3.1%	5.8%	5.7%	16%
Italy	5.2%	10.4%	7.6%	17%
Lithuania	15%	19.7%	16.6%	23%
Luxembourg	0.9%	3%	2.9%	11%
Latvia	32.6%	32.6%	34.0%	40%
Malta	0%	0.4%	2.0%	10%
Netherlands	2.4%	3.8%	4.7%	14%
Poland	7.2%	9.5%	8.8%	15%
Portugal	20.5%	24.6%	22.6%	31%
Romania	17.8%	23.6%	19.0%	24%
Sweden	39.8%	49.1%	41.6%	49%
Slovenia	16.0%	19.9%	17.8%	25%
Slovakia	6.7%	9.8%	8.2%	14%
UK	1.3%	3.3%	4.0%	15%
EU	8.5%	**12.7%**	**10.7%**	**20%**

The most objective measure is to judge Member States against their first interim target, calculated as the average of their 2011/2012 shares. Whilst on average such progress to 2010 is good, this does not reflect the policy and economic uncertainties that renewable energy producers appear to face currently.

Progress towards the first interim target:

>2% above interim target

<1% from or <2% above interim target

>1% below interim target

Source: Renewable Energy Progress Report, March 2013, Com (2013) 175 Final

Capacity mechanisms

These are government-organized systems of separate payments to generators to ensure that they are ready to provide power to the market when supply falls short of demand. So they are subsidies to maintain a ready reserve of generation 'capacity', generally gas- or coal-fired plants because these can be switched on and off dependably and

fairly quickly. These capacity mechanisms should be distinguished from traditional short-term 'balancing' mechanisms or markets in which sudden variations in supply or demand need quick, or (in the case of electricity), instantaneous correction to restore balance; fast-reacting hydroelectricity is often used for this. However, expansion of balancing markets can play a role in easing the capacity problem.

Renewable energies that have the greatest scope for expansion – such as wind and solar power – complicate the economics of capacity back-up because they are not only intermittent energy sources but are also free, in the sense that they have virtually zero marginal or running costs. This feature puts them first in the 'merit order': the traditional line-up in which electricity grid operators call upon generators to supply demand. This dispatching system starts, logically, with the cheapest source of power, and moves to the most expensive source until all demand is satisfied. Financially, this means 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 (often likely to be gas or coal) has been able to cover its higher fuel cost, while the cheaper generation source with zero or low marginal cost (wind, solar, nuclear) can make enough money to cover its capital costs that are high relative to its fuel costs.

However, given the volume of subsidized renewable energy now coming on to the grid in some countries, the 'first' in the merit order can also be the 'last'. In other words, renewable energy can, at times of high wind and solar generation, supply the entire demand without gas or coal plants being called on and being able to earn any money. Moreover, when renewable energy supply not only fulfils demand, but exceeds it, the market price goes negative. This is now happening several times a year in Germany, where renewables producers, with their near-zero operating costs, are ready to pay a power exchange to take their electricity, provided that penalty price is less than the subsidy they get for continuing to generate.

Some analysts argue that the current design of energy-only markets – where the only revenue comes from the sale of energy commodities and there is no subsidy – may never be able to cover the capital costs of intermittent wind and solar power, no matter how competitive these renewables become [5]. The reason is that when these renewables generate electricity, they do so uncontrollably, sometimes driving the power price on exchanges to very low levels – even to zero or negative. When the

wind stops, the price rises, but at that point wind farms have nothing to sell. The daily cycle of solar power is generally better matched with demand from the working day than wind is. In certain sunny countries such as Spain and Chile, some developers have started to build solar PV without subsidy because falling technology costs, coupled with good solar resources, have brought solar PV to grid parity with conventional fossil fuels there. However, they may find that, as solar capacity builds up and periodically surges on to the market in ever-greater quantities, solar power may still 'destroy' its own market price. The logic of this analysis is that intermittent renewables will require permanent subsidy – unless the pricing of electricity is reformed so that generators are rewarded, not as today for the volume of electrons sold, but for the reliability of the service provided [6].

The intermittency of renewables makes all other energy sources in the marketplace intermittent too This is bad business for the owners of gas and coal plants. If their plants can only operate for a couple of hundred hours a year, it might not matter to their owners, provided they can capture the very high peak prices a free market would produce during those hours. But investors in conventional energy suspect that politicians would not dare risk upsetting voters with such peak prices, and that they will therefore cap prices. The obvious back-up for renewable energy is fast and flexible gas plants. But gas is more expensive than coal in Europe at present. Few companies in Europe are planning to build any new gas plants, and some companies have mothballed existing plants in the hope of getting capacity payments.

Capacity mechanisms are controversial. In planning capacity markets, the UK and other countries are making 'a colossal error', according to Walter Boltz, Austria's outspoken national regulator.

> We made the problem ourselves with the growth in renewables, so let us think of how we can fix it without killing the market [7].

However, the Council of European Energy Regulators (CEER), of which Mr Boltz is a member, concedes that 'energy only' markets, meaning markets where a generator's only revenue comes from selling his energy, may have 'some market flaws that lead to a sub-optimal level of generation adequacy' [8]. The regulators went on to say that 'pure energy-only market designs have an inescapable tendency to produce scarcity from time to time', adding that it was difficult for regulators to distinguish between efficient (in other words, genuine) scarcity prices, and prices that reflect market power

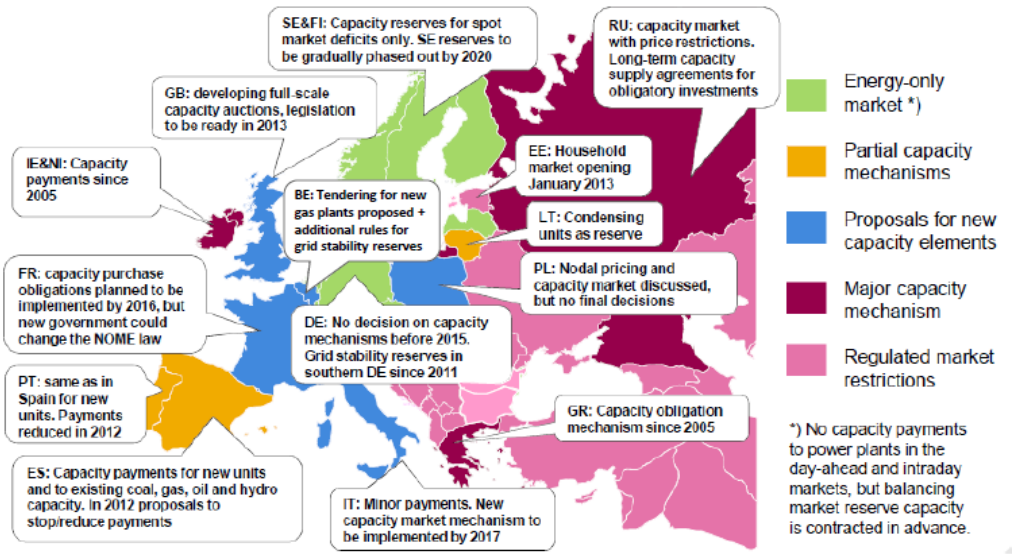
(that is, possibly affected by manipulation) during periods of scarcity. In any case, the regulators did not believe that 'policy-makers [i.e. politicians] are generally willing to accept potentially severe prices spikes and the demand rationing associated with energy-only markets'.

For its part, the European Commission has now conceded that its 2009 energy and climate package:

> … underestimated the impact on market integration of 27 different national support schemes for renewables [and] did not address the issue of whether the market offered the necessary incentives to invest in generation, distribution, transmission and storage capacity in a system with greater shares of renewables [9].

What particularly haunts the Commission is the prospect that the combination of national renewable and capacity markets would effectively shut off countries' energy sectors from each other, and negate much of the painstaking work, described in other sections of this paper, of building cross-border interconnectors, agreeing pan-European network codes, and coupling power markets. Many in the EU executive feel that they let 'the genie out of the bottle' by conceding that member states could run their own renewable support programmes, and do not want to make the same mistake again with national capacity schemes. But the capacity genie is already uncorked. Several member states already have capacity mechanisms. Sweden and Finland pay certain generators to maintain a strategic reserve; Ireland, Spain, and Portugal make more broadly based capacity payments; and the UK and France plan capacity auctions or markets (see Figure 7).

Figure 7: National capacity mechanisms and plans



Source: Eurelectric presentation. 2013.

More specifically, the Commission fears that national capacity mechanisms, especially if badly designed or introduced unevenly in some countries and not in others, could distort investment. Capital investment would be attracted to states paying the most for capacity, just as it follows the more generous of national subsidies for renewable energy. They could also distort trade. Extra investment in a country with a capacity mechanism could create an artificial surplus of power there, encouraging more cross-border trade that would overload available interconnectors. In addition, such a mechanism could create a re-distributional effect, with citizens of a country with a capacity system paying for security of supply for citizens in another member state without a capacity scheme. Finally, the Commission fears problems from whichever type of capacity system a country chooses. A strategic reserve of the Swedish or Finnish variety has only a limited impact on the wholesale energy market, because it is rarely called upon. However, it only works to improve the supply side by adding or maintaining generation capacity. In contrast, a capacity auction of the kind the UK is proposing would allow providers of demand reduction, as well as suppliers, to bid for capacity payments – thereby impacting both sides of the energy equation. But capacity markets are more complex to design and administer.

Remedies

The Commission has the legal power, under its right to review state aid and public service obligations, to restrict and even block national renewable and capacity subsidy schemes. And it may have to use this power in the case of the UK government's proposed Electricity Market Reform soon, as this presents an unusually difficult challenge to the state aid regime [10]. For this reform consists of a series of state-organized guaranteed prices for renewables and (for the first time) for nuclear power, with no provision for phasing out or reducing these price guarantees. It also introduces a capacity market.

Normally, the EU executive has allowed states to pay declining amounts of aid to renewables projects because these are viewed as necessary, proportionate, and in pursuit of an agreed EU policy goal: low-carbon energy. As a matter of practical politics, the Commission may take the same broadly permissive attitude towards states organizing capacity payments to keep the lights on – provided these are deemed necessary and proportionate – because security of energy supply is also an agreed EU

policy goal. The Commission may feel it cannot afford, especially given the shaky political state of integration in today's Europe, to be seen to thwart member states in the exercise of their legitimate right to try to assure their own energy security. Moreover, there is no easy European alternative to national capacity schemes. Technically, an EU-wide scheme would have been easier to introduce for renewables than for capacity. The aim with renewables is just to add supply, whereas capacity affects both sides of the equation – demand and supply – and the balance between them.

In the absence of a pan-European capacity scheme, what should member states do? All member states would benefit from improved pricing in short-term electricity balancing markets. At present, producers of renewables are held responsible for the imbalances they create in the system in only 15 member states, and elsewhere many such producers are 'free riders' on the balancing system. What is needed are balancing markets in which all are held financially responsible for correcting imbalances at marginal prices that reflect the extent of the imbalance. 'People who cause the problem should pay and people who solve it should be rewarded', comments an ENTSOE official [11]. The aim is to ensure that price signals reflect the correct value of electricity at each point of time during the day of delivery (the value can be very different from moment to moment) something that the traditional day-ahead trading market cannot provide. Even the UK, which has a relatively efficient balancing market, is concerned that the averaging of prices in its balancing mechanism does not provide sufficiently sharp price signals as rewards and penalties, and it is seeking to reform this. At the moment, however, there is often an impasse in the development of balancing markets: renewables producers claim they cannot be held responsible for balancing until liquid balancing markets develop, but such markets may not emerge until it is clear that all producers (including those of renewables) will participate.

However, the big issue, from the Commission's viewpoint, is how to Europeanize national capacity mechanisms and to ensure that they do not cut across its single market plan. It would be easy to forbid national hoarding of energy; it would clearly be illegal, under standard EU internal market rules, for a government to ban any export of energy to its EU neighbours. It might be possible to pressure member states

into preparing the ground for greater mutual dependence through building more cross-border interconnectors. The Commission could use its state aid powers to make approval of national capacity mechanisms conditional on member states putting aside a certain proportion of their capacity subsidy money for the building of such links. EU governments may have laid themselves open to Commission pressure on this point, when in their May 2013 special meeting on energy EU leaders agreed, among things, to take:

> … more determined action to meet the target of achieving interconnection of at least 10 per cent of installed electricity capacity [12].

This 10 per cent figure was set at an EU summit in 2002; it is fairly arbitrary, has never been reached in the case of islands (UK, Ireland) or peninsulas (Iberia, Italy), and until it suddenly re-surfaced at the May 2013 summit it was never seen as much of a commitment. It may, however, regain significance. The Commission could use internal market and anti-trust rules to insist that governments allow all EU participants, at least in theory, to bid into their national capacity schemes.

But, in practice, the Commission cannot insist that countries rely on their neighbours, or that they treat every bid from across the border to provide emergency power as 100 per cent firm and deliverable. In other words, a French or Dutch company might contract to provide power to the UK, but be unable to deliver it because of interconnector congestion across the Channel. Because of regional weather patterns, when one European country experiences a sharp drop in wind and solar power and/or a sudden increase or decrease in temperature and therefore demand, the likelihood is that its neighbours will suffer in exactly the same way. So a wide swathe of the European grid would come under stress simultaneously. These are factors that each operator of a national capacity scheme will have to take into account, and which cannot be second-guessed from Brussels.

One solution to doubts, at times of emergency, about the firmness of cross-border deliveries would be permanent reservation of capacity for them. But such permanent reservation would subtract from the capacity available for day-to-day trading, and as shown in the next section, this is already insufficient.

4. Infrastructure – stitching the market together, slowly

The rapid deployment of renewables has increased the need for infrastructure. Much of this infrastructure is within member states, because most new renewables, especially wind and solar power, tend to be connected to the low-voltage distribution network rather than to the high-voltage lines that traverse frontiers. The EU has no real remit over these purely national networks. But the Commission has always promoted cross-border infrastructure as being the linchpin of its internal energy market programme. And recently, it has sought to accelerate cross-border infrastructure development, precisely to counter what it sees as the risk of national renewable and capacity schemes returning Europe's semblance of a single energy market to autarkic national fiefs.

In the past the Commission focused more on the use of energy infrastructure, rather than on actually contributing to building it; it first sought to abolish monopolies and then to remove discrimination on networks by means of anti-trust measures and traditional market-opening legislation – these moves culminated in the 2009 'Third Package'. The Commission has now broken new ground by involving the EU in the building of new infrastructure, by means of a new regulation which took effect on 1 June 2013. This is aimed at identifying major European 'projects of common interest' (PCIs) and at streamlining national permitting procedures and providing some EU finance for such projects.

In 2011, when the Commission came up with its proposal for this infrastructure regulation, it estimated that around Euros 210bn needed to be spent by 2020 on extending electricity and gas grids and upgrading existing ones. This overall figure was made up of Euros 100bn for high-voltage transmission (Euros 70bn onshore, Euros 30bn offshore), another Euros 40bn for electricity storage and smart grid applications, and Euros 70bn for high-pressure gas transmission gas pipelines, storage, LNG terminals, and reverse-flow infrastructure [13].

The prolonged economic downturn has made it harder to raise private finance for infrastructure investment. Even in 2011 the Commission conceded that of the Euros 210bn, half:

> … should be delivered by the market unaided, whereas the other Euros 100bn will require public action to source and leverage the necessary private capital [14]

Delays in the planning and permitting process – which can take up to eight to ten years for new transmission lines – are a major reason why infrastructure investment fails to materialize. Permitting delays add to cost. They also add to uncertainty, which in turn increases risk, and this may cause financiers to increase their required rate of return beyond the level a project can produce. Public acceptance is harder to win for electricity cables, which are three to ten times more expensive to bury than to string between overhead pylons, whereas gas pipelines are routinely buried.

In recent years, the EU has tried other measures to create some of the missing links in Europe's energy networks. These included the appointment of special negotiators, for example, Mario Monti who successfully concluded a Franco-Spanish negotiation on a trans-Pyrenean power line – this project had been rejected in 1996, re-started in 2001 and finally concluded in 2011. There was also the Trans-European Networks programme, or TEN, set up in 1996. The energy part (TEN-E) of this had a tiny budget (Euros 20m a year), essentially to finance feasibility studies.

> At the time it was assumed that only a relatively small initial impulse from Brussels would be needed to set in motion the market forces that would drive construction of all necessary cross-border links. [15]

Moreover, the TEN-E list of projects was the sum of every state's wish list, amounting in 2011 to a *short* list of 568 priority projects of European and national interest.

The Infrastructure Regulation of 2013

Under the new regime, the *long* list for 'projects of common interest' (PCI) starts with 420 projects, and this number will be winnowed down by autumn 2013 to 150 (100 for electricity and 50 for gas). Once a project gets PCI status, it can benefit from a national permitting process that, under the new EU regulation, should not last longer than three and a half years. This period is composed of: two years for the project promoter(s) to make all the necessary applications and carry out environmental impact assessments; and 18 months for national planning authorities to come to a decision. The only significant modification made by EU legislators to the Commission's draft regulation was to extend the permitting process from three to three and a half years. It had been thought that the regulation's requirement that each

member state set up a one-stop shop – a body with the power to decide, or at least co-ordinate, permitting for PCI projects – would pose difficulties to countries with a federal system. But acceptance was made easier by the fact that federal Germany had already decided to pass decision-making power on major energy infrastructure to its network regulator.

The new legislation specifically directs national regulators to take a wider cross-border view of the costs and benefits of trans-frontier infrastructure, and to allocate the costs appropriately to match the benefits. To take the example of a planned new Hungary–Slovakia gas interconnector (most of which has to be constructed in Slovakia while most of the benefit of improved security of supply will go to Hungary): it will be up to the Hungarian regulator to ensure that most of the cost will be borne by Hungarians. PCI projects will have to show that proper cost allocation has been carried out, before seeking any EU funding.

EU funding for energy infrastructure so far amounts to:

- Of the Euros 4bn devoted to energy in the 2009 European Economic Recovery Programme, Euros 1.36bn went to gas infrastructure, and Euros 904m to electricity infrastructure.
- As part of the Multiannual Financial Framework (MFF) for 2014–20, the Connecting Europe Facility originally slated Euros 9bn to energy infrastructure, but in the ongoing MFF negotiations this has been cut to Euros 5bn.
- Most of the large sum lent by the European Investment Bank (EIB) to the energy sector – totalling Euros 11.5bn in 2011 – goes to renewable energy generation and energy efficiency projects, rather than to infrastructure. But the EIB is piloting a project bond scheme in 2013 that could eventually leverage fairly large amounts of private sector lending into infrastructure investment. The EIB will not issue the project bonds itself. Instead, as part of project bond operations led by the private sector, the EIB will make loans, or issue loan guarantees, which would be subordinated to those of senior creditors such as private investors. The idea is to raise the credit rating of these project bonds, and so entice investors back into the infrastructure finance that has been more

or less deserted by European banks preoccupied with their solvency and liquidity problems.

These financial initiatives mark an important political step forward for direct EU involvement in infrastructure, but this EU money is very small when compared to Europe's overall needs. Of much greater potential influence is the behaviour of national regulators. They have the power to conjure new infrastructure into existence, because they decide the rate of financial return on Europe's major regulated electricity and gas transmission grids.

However, regulators are usually under pressure from their governments to keep transmission tariffs low, and TSOs often find it hard to raise new money for investment on the capital markets. In electricity, all east and central European TSOs are majority state-owned, as are some in west European countries such as France and the Netherlands. In gas, most large east and central European TSOs are majority state-owned. State-owned or state-controlled TSOs used to have a credit advantage in being owned by governments because this elevated them to sovereign risk status. These days, such sovereign risk status can lead to a credit demotion. Even when that is not the case – which is the situation for the two Dutch state-owned TSOs Gasunie and TenneT – governments are reluctant to inject more capital into their TSOs, especially if this is designed to help them in activities outside their national boundaries. TenneT has expanded into north-western Germany, but has found itself without the resources to connect up German wind power operators to its electricity grid as fast as they would wish. For their part, Dutch politicians and taxpayers see no reason to pay to help Germany meet its renewable energy targets.

Generally, there seem to be enough investors, both to participate in existing infrastructure projects, and to buy the assets that some energy groups are selling as a result of EU pressure to unbundle their transmission systems. For instance, E.ON and RWE found buyers for the electricity and gas grids they wanted to sell. But there appears to be little investor appetite for new infrastructure at the moment.

One contributory reason for this lack of investor appetite might be the complexity of the unbundling provisions of the 2009 Third Package of legislation. This was designed to remove, once and for all, the inherent conflict of interest in companies

owning both energy supply businesses and transmission networks that could be used to favour those energy supply businesses. The solution was to separate supply from transmission in two ways. One gives member states the option of allowing their energy supply groups to maintain formal ownership of transmission systems, but requires the energy groups to put their networks under independent management, with strict supervision to guarantee this independence of management. The other option for member states is ownership unbundling, requiring separate ownership of transmission and supply.

In theory, this second option, which had been the Commission's preference, involves far less red tape and supervision, because the elimination of joint transmission/supply ownership should mean an end to any conflict of interest between the two activities. In fact, those who own or manage an 'ownership unbundled' TSO have to be constantly on their guard not to give any significant shareholding or control to investors who have any controlling interests in energy supply businesses. Yet these totally unbundled TSOs – unless they are owned by governments that can fulfil all their financial needs – will need access to private capital markets. Independently owned TSOs, therefore, must be choosy about their investors if they are to be certified by the Commission as 'ownership unbundled'. Moreover, they must exercise this care constantly. Under the terms of the 2009 legislation, once a member state and its TSOs opt for ownership unbundling status, they cannot go back on this and revert to joint supply/transmission ownership. There is no evidence yet that the unbundling provisions of 2009 have actually deterred investment in energy infrastructure, but the complexities of the legislation hardly encourage expansion of the sector.

By contrast, the 2013 infrastructure regulation was a more straightforward way of encouraging the expansion of energy interconnectors. It also marked an advance in the politics of EU energy policy, because it took the EU into new areas of transmission planning and financing. But, unfortunately for proponents of the Commission's single market, the forces of integration, as represented by the building of cross-border infrastructure, have lagged behind the forces of single market disruption unleashed by national renewable and capacity subsidy schemes.

5. Market coupling, network codes, and other tools of integration

The work of market unification is also being applied to existing infrastructure through techniques such as market coupling, harmonized trading arrangements, and agreements on network codes. These are key elements in what is called 'completing the internal energy market'. This section aims to describe this technical task with just enough detail on the main elements to demonstrate that it is a complex, and necessarily slow, affair. Some of this work, too, has been outpaced – and in the case of market coupling and price convergence even reversed – by renewables surging erratically onto the markets of certain countries.

The work of market unification is chiefly carried out by the European groupings of national energy regulators – the Agency for Cooperation of Energy Regulators (ACER) and the Council for European Energy Regulators (CEER) – and the European-level organizations of TSOs – the European Network of Transmission Systems Operators for Electricity (ENTSOE) and the European Network of Transmission Systems Operators for Gas (ENTSOG). The plan for the completed internal EU energy market – to be achieved by 2014 as stated by EU leaders in 2011 – has been set out in an Electricity Target Model and a Gas Target Model, and agreed among all stakeholders: Commission, regulators, TSOs, industry associations, energy exchanges, traders, and consumers. The aim is to harmonize cross-border trading arrangements and to integrate national markets through efficient use of infrastructure carrying electricity and gas to where they are valued most.

Crucial to this construction job are network codes that, in a sense, provide the plumbing to ensure that energy trade can flow, and flow smoothly through the wires and pipes. These EU network codes – which when adopted by 2014 (under current assumptions) will supersede national network codes – are being drafted by ENTSOE and ENTSOG, working under the supervision of the Commission and ACER. It is unusual to ask one part of an industry to draft rules for the rest of that industry. TSOs, though now unbundled to various degrees, are still commercial organizations, and their quasi-legislative role has been queried by some other energy companies. However, they have been judged to be the only organizations with the expertise to carry out this technical task.

Electricity

Prices

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. But it is a measure that cannot be sensibly applied to retail prices. These are heavily influenced by national governments, both by taxes and, in many cases, regulation. In 2011 end-user prices for households were regulated in 17 member states, and for non-households in 12 member states, a state of affairs that the Commission has sharply criticized. EU rules only permit regulated prices in strictly limited circumstances – to protect poor and vulnerable customers. Moreover, if retail prices are set below the level of cost recovery, they may depress power generation and will certainly discourage new investment and new entrants into the market.

Retail end-user prices may therefore be a measure of political integration (or lack of it) in the sense of member states flouting EU rules. However, because they reflect more than just supply and demand, they are a much worse guide to market integration than the convergence of wholesale prices.

As ACER and CEER have shown (see Table 2 below), recent years have seen convergence in Dutch, Belgian, French, and German wholesale spot power prices in the Central West Europe (CWE) region, even though within the past year (2012/13) surges of renewable power, seen particularly in the German market, have often driven prices apart again. Prices in Spain and Portugal have tended to converge with each other, and the Iberian average with the CWE level. More erratic is the pattern in the Nord Pool countries, where reservoir levels affect the price of hydro-electricity. Increasingly important in this convergence is the mechanism of market coupling, which has led to an equalization of cross-border prices for longer periods, at least until recently. However, in 2012 abundant wind and solar power and cheap coal-fired generation pushed prices in Germany down, while problems with the availability of French nuclear power pushed prices in France up. It was the first period of wholesale price divergence, after several years of steady price convergence.

Table 2: Annual average price at European spot exchanges – 2005 to 2011 (euro/MWh)

Area	2005	2006	2007	2008	2009	2010	2011
CWE							
Netherlands	52.4	58.1	41.9	70.1	39.2	45.4	52.0
Belgium	NA	NA	41.8	70.6	39.4	46.3	49.4
France	49.3	49.3	40.9	69.2	43.0	47.5	48.9
Austria	46.4	51.0	39.0	66.2	38.9	44.8	51.8
Germany	46.0	50.8	38.0	65.8	38.9	44.5	51.1
NORDIC							
Nord Pool	29.3	48.6	27.9	44.7	35.0	53.1	47.1
MIBEL							
Spain	53.6	50.5	39.4	64.4	37.0	37.0	49.9
Portugal	NA	NA	52.2	70	37.6	37.3	50.5

Source: ACER/CEER Annual report on Electricity and Gas Markets, 2012.

Market design

'Market coupling' deals with the problem of transmission capacity congestion that so often occurs at national borders in a system originally designed around nation states. Among other things, it is aimed at preventing situations in which a seller of power on one side of the border gets a deal to deliver power to the other side of the border, but then finds he cannot get the capacity to transport the power. Market coupling allows buyers and sellers to trade electricity without explicitly having to buy the transmission capacity needed to make the trade. This works by a power exchange (or usually two, one on either side of the border) taking all the trans-border transmission capacity that the TSOs have declared to be available for any period of time, and using a clever algorithm to 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. The system allows transmission capacity to be used efficiently, and prices to act as a signal for the logical flow of power – from lower price areas to higher price areas. As a result of market coupling in the CWE region, what are called 'adverse flows' – from higher to lower price areas – have more or less disappeared. By contrast, these adverse flows of electricity, moving in 'the wrong direction' in a commercial or economic sense, remain frequent in Central East Europe, where market coupling only exists between two countries that used to be one – the Czech Republic and Slovakia – and Hungary.

This coupling of electricity markets has been proceeding fairly steadily. It was pioneered by Nord Pool, then in 2006 France, Belgium, and the Netherlands adopted a 'trilateral' coupling of markets, and in 2010 Germany and Luxembourg joined in to form a 'pentalateral' market coupling. There are now 17 member states with markets that are coupled to neighbouring markets, although not all 17 are directly linked to each other. The next significant milestone will come in November 2013, with the planned market coupling for day-ahead trading of North West Europe (composed of the Central West Europe region of Austria, Belgium, France, Germany, Luxembourg, and the Netherlands plus the four Nordic countries and the UK). Estonia, now linked to Finland, will probably couple its market at the same time, and Spain and Portugal soon thereafter.

But, realistically, this is likely to be the full extent of market coupling in 2014, despite the aims, set out in the Electricity Target Model, that by 2014 there should be:

- a single European price for day-ahead trading which would replace all remaining explicit capacity auctions on cross-border interconnectors.
- A single continuous platform for intra-day trading. This is important for renewable energy suppliers who need to trade as near to 'gate closure' (the time of actual delivery) as possible, in order to take account of the weather-related variations in their supply and therefore to minimize the imbalances they can cause.
- A single European platform for the allocation of long-term transmission rights, which market coupling is not designed to cope with.
- A flow-based allocation in highly meshed networks. Instead of just involving whatever spare capacity that TSOs care to declare as available on a particular border, this flow-based approach to capacity allocation would incorporate all available capacity in a price-coupled region, not just on its borders. The idea is to make even more efficient use of existing transmission capacity in a Europe where the building of new pylons and power lines is taking so long. The flow-based approach makes particular sense when attempting to maximize available capacity in and between member states with multiple borders and highly meshed grids, such as those in the centre of western Europe. For the moment, this idea is just at the stage of trial simulations in the Central West Europe region.

Network Codes

ENTSOE and ENTSOG were given the difficult task of drafting EU network codes with a very tight timetable. Each network code (NC) is typically a three-year project between concept and delivery. This allows ACER six months to produce framework guidelines for the TSOs. The latter then have 12 months to draft the NC, which ACER then has three months to assess before either recommending adoption or asking for more work. If and when that process is over, the NC goes to comitology for the Commission and member states to write into EU law. Writing law to a deadline is challenging, and the time for consultation has been short. Some companies, especially in the electricity sector, have complained that the TSO organizations are imposing stringent requirements on them without sufficient cost/benefit analysis as justification. This is a criticism that the TSOs partly accept, but argue that it is inevitable given the time pressure.

Among the nine main NCs in electricity, the most important are:

- *Requirements for generation*. There used to be some regional codes for generation in the Nordic area, but most were national, and were not aligned or harmonized with each other. This had disadvantages for industry, because manufacturers of turbines had to produce different designs for different standards. The importance of the new code (which categorizes generators according to size and connection voltage) for the TSOs, is that it gives them more technical certainty about how services such as balancing for renewable energy will be carried out.
- *Requirements on frequency*. This sets common rules on voltage in synchronous areas (GB–Ireland, Nordic region, the Baltic states, continental Europe). Generating companies have complained about the cost of requirements which, unsurprisingly, increase as the size of generator increases. Some generators also complain about the lack of cost/benefit analysis, but ENTSOE points to the time pressure from ACER.
- *Capacity Allocation and Congestion Management*. This relates to markets, in line with the target model of progressive harmonization of trading arrangements along the time line, starting with day-ahead and moving to

continuous trading. It set a rule about the firmness of orders, and what happens to firm orders if transmission capacity is subsequently constrained. This code also defines bidding zones as areas within which energy flows without any congestion. The size of bidding zones helps to determine the degree of competition and the number of buyers and sellers, to fix prices according to the proximity of supply to consumption, and, through prices, to send signals about possible new investment. This NC defines capacity allocation, which will become more complex with the move towards flow-based allocation that is important for the more meshed grids of continental Europe. Assessing capacity is vital for market coupling. This is done through the power exchanges, which take the available capacity, together with the bids, and use their algorithms to set the price in a coupled market. This puts power exchanges, which are non-regulated commercial entities, in a potentially powerful position, and it has been suggested that power exchanges should be regulated in some way. For their part, the power exchanges claim they can regulate each other, because several of them will be running the algorithms, thereby preventing monopoly power.

- *Demand connection code*. This covers all big electricity users such as factories. But it also contains a controversial provision that would require temperature-controlled devices, like refrigerators, to be able to react to frequency disturbances in order to keep the grid stable. This is a mandatory requirement for demand-side reduction. But some electricity users argue that they should be paid for providing this demand-reduction service and that if they are not to be paid, then this requirement should be legislated through standard EU law-making procedures and not rushed through in secondary legislation.

Gas

Prices

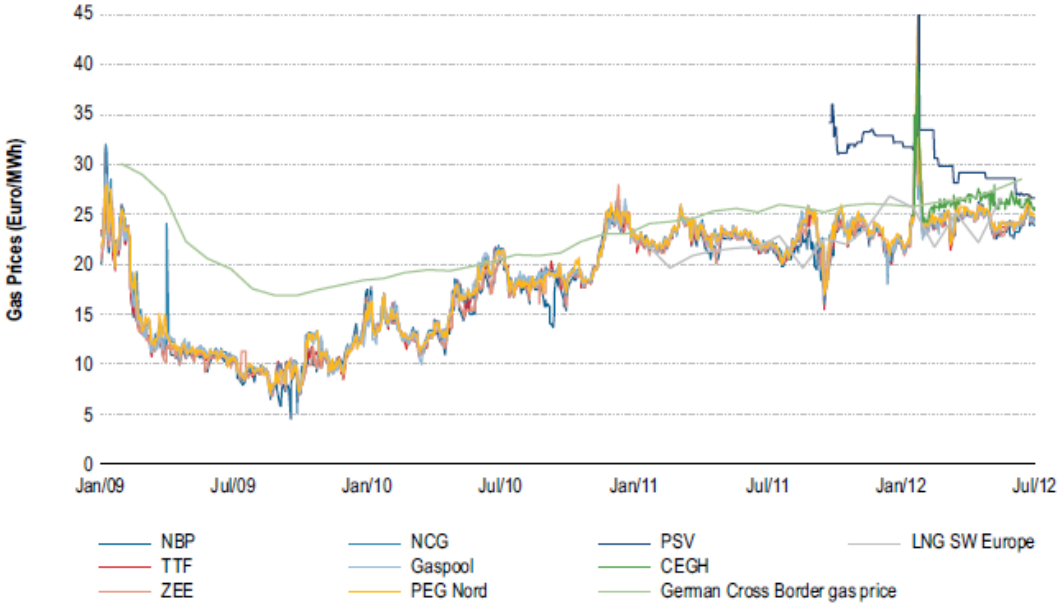
Gas prices have increased less than those of oil. This is because recession has reduced demand for gas, because imports of cheap US coal (displaced by the shale gas glut in the USA) have displaced gas in power generation, and because more gas is being traded on a spot basis at European hubs while relatively less is being sold on oil-indexed contracts (chiefly from Russia). The volume of gas traded in continental

Europe on a spot basis rose by 27 per cent between 2010 and 2011, and this has helped wholesale prices of gas to converge.

Again, retail prices of gas, as of electricity, are not the result of pure supply and demand forces, but are often the result of considerable state intervention in terms of taxes and regulation. End-user prices for households are regulated in 16 member states, though not for industry, and most new member states regulate retail gas prices. However, because the initial communist-era price level in these countries was so low, the percentage increase in some of east and central Europe's regulated prices has been higher than in some west European countries where there was no regulated cap on retail gas prices. Nonetheless, there was a wide dispersion in end-user prices in 2011 according to the ACER/CEER monitoring report: a spread of 1:4 in household prices between Romania (a gas producer itself) at the bottom and Sweden at the top, and of 1:3 in industrial prices between Romania at the bottom and Denmark at the top.

At the wholesale level, gas prices show some degree of convergence (see Figure 8 below). The tightest correlation is between the three main gas hubs in north-west Europe (NBP, TTF, and Zeebrugge) which have good physical interconnection. This region is beginning to influence the German gas market, which is moving towards hub pricing and away from oil-indexed contracts. The Italian PSV hub price (in dark blue) and the Austria–Slovakia border's Central European Gas Hub price (in green) have also started to come into line fairly recently. All hubs showed the sharp price spike caused by the very cold weather of February 2012. There is still a pricing disconnect with parts of eastern and southern Europe that suffer from a lack of diversity of supply, a paucity of connecting pipelines, a scarcity of LNG, and (because of all this) an absence of trading hubs.

Figure 8: Wholesale day-ahead gas prices at selected EU hubs – 2009–12 (Euro/MWh)



Source: ACER/CEER annual report on electricity and gas markets, 2012.

Some of the price differences reflect transport costs, which are a relatively bigger item in gas than electricity bills, reflecting the reality that electricity is usually generated close to demand whereas gas often travels thousands of kilometres. But it is alleged that much is also due to capacity congestion at cross-border interconnectors, and that some is due purely to 'contractual congestion' (where transport capacity is fully booked but not fully used). The European Commission's competition authorities have tried to crack down on such contractual congestion where this appears to be a deliberate strategy of hoarding. Nonetheless, ACER/CEER looked at seven interconnectors with 100 per cent fully booked capacity in 2011, and found that their actual utilization ranged from 92 per cent down to 42 per cent, with a central value of around 60 per cent.

Market design

Unlike electricity which, is mostly generated and consumed within national borders, a large portion of Europe's gas comes from far away and is transported by pipeline across several EU states before reaching its destination. The transport regime for gas is therefore crucial. In terms of unifying and simplifying the transport of gas, the EU has chosen as its basic building block so-called entry–exit zones (EEZs). These are required by the Third Package of legislation [16], which stipulates that transport tariffs or costs should be independent of 'contract paths' or the actual distance

between the source of gas and the point of consumption. In these EEZs gas can enter at any point or leave at any exit point, at prices which are not directly connected to the distance that gas may have travelled.

European countries used to have a system that more closely resembled that of the USA, with inter-state transport and trading of gas being largely governed by long-term contracts in which transport tariffs are calculated on a point-to-point system, taking account of the underlying infrastructure costs, with trading taking place at physical hubs – such as the famous Henry Hub – formed by pipelines coming together and also providing useful locations for storage and balancing. Underpinning this so-called point-to-point system were the well-defined property rights to, or long-term contracts for, transmission capacity that had been crucial to funding the building of long-distance pipelines within the USA and also between Russia and western Europe. However, the European Commission concluded that many of these long-term gas transport contracts were effectively cosy arrangements between Europe's gas importers and outside suppliers that cartelized the market against new entrants and thus helped sustain the increasingly artificial pricing of gas by indexing its price to oil product prices.

So the EU 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. The EEZs, which coincide with the 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). They lower transaction costs because gas is priced and traded regardless of its location within the EEZ. The cost of transport and network services is separated from that of the commodity, and '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 [17]. Liquidity attracts liquidity, as buyers and sellers benefit from always being able to get a good price, and Europe's gas consumers and users can be more certain of purchasing gas that has been bought on a market where large volume makes the price

difficult to manipulate. Moreover, it is easy to see the ideological attraction to the Commission of EEZs, because they are mini-versions of Europe's single market.

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 small enough for any physical constraints resulting from different gas flows not to generate excessive internal congestion charges. Distance may have been 'abolished' commercially inside the EEZ for traders, but physical flow of gas still needs to take place as required by the network users. 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.

> Therefore the larger the trading zone, the larger the amount of infrastructure that needs to be kept out of the market to guarantee the greater trade flexibility permitted within the larger trading zone. [18]

Moreover, the larger the zone the greater the degree of cross-subsidization of transport costs, with shippers using a lot of transport effectively subsidizing those who use little.

A further complication is that within the EEZs there are no locational price signals, or price spikes at particular bottlenecks, to pinpoint congestion and incentivize investment in new pipelines to resolve the bottlenecks. So, because transport price signals become blurred inside EEZs, in the opinion of some experts, regulators may have to take more of a lead in determining new transmission investments both inside EEZs and particularly between such zones. [19] This is the view of one regulator, Walter Boltz, head of Austria's E-Control, who has said that:

> … increasingly, regulators will decide what needs to be built because shippers will not commit themselves to long-term investments in cross-border pipelines.

It is therefore hard to see these EEZs being enlarged much further. Most will probably remain at the national level in size. Some may stay sub-national. The number of gas trading/balancing zones has been greatly reduced in Germany – originally 19, down to six zones, with a further reduction in 2011 to two zones, run by the TSOs, NetConnect Gas and Gaspool. The German TSOs recently claimed that the cost of merging the two zones into one would be an extra Euros 395m in the first year after the merger, for a financial benefit to the market of less than Euros 60m a year, and that the extra

investment required to maintain current levels of service in the merged zones would be nearly Euros 3bn. [20]

In principle, according to the widely accepted Gas Target Model, any gas market that is smaller than 20 billion cubic metres in annual consumption, and with fewer than three suppliers, should merge with another. In practice, the only market likely to acquire a multinational, regional dimension is the Central European Gas Hub, which announced in January 2013 that it was switching from being a point-to-point trading hub to being a virtual hub with an entry–exit system. It is already a key hub for Russian gas flowing into Austria, and thence on to Germany and Italy, and as an EEZ it could eventually be extended to the Czech Republic, Slovakia, and Hungary. As yet, few EEZs exist in south and south-east Europe. The upshot is that no one is predicting the total number of EEZs across Europe will fall below seven.

An alternative suggestion is to improve the links between EEZs by making better use of cross-border interconnector capacity through market coupling, as in electricity. But this is not proceeding as fast as in electricity. There is a pilot project to couple gas zones in France. The Dutch and German gas markets are coupled, through the common ownership, by Gasunie, of gas grids on both sides of the border. And this year, 2013, has seen the launch of a proto-European gas capacity booking platform by 19 TSOs from Austria, Belgium, Denmark, France, Germany, Italy, and the Netherlands, though this will lack the automaticity of real market coupling. [21]

The reason for the relative slowness of market coupling in gas is the strong aversion that many gas industry players have to the concept. They argue that there are fundamental differences between gas and electricity. Electricity is generated and consumed locally, with a bit of spillage to export to, or shortage to import from, neighbouring countries with often very different prices – so why not develop an automated process for price comparison between adjacent markets for short-term trading of fairly small quantities of power in relation to total electricity consumed? However, many in the gas industry dislike market coupling because the usual approach in electricity appears to put almost no value on transport, which is a very important feature of the gas industry. Gas often comes from far away, and the gas industry, they say, has had to develop longer term arrangements to underwrite investment in extraction and transport. So gas has been traded on long-term contracts

that already incorporate the value/cost of transport, with the end-consumer often paying for the gas network in several other countries as well as his own. The gas industry acknowledges that there can be congestion, particularly contractual congestion, on cross-border interconnectors between EEZs and national markets. However, the problem should be resolvable in the secondary capacity market. Concerns about hoarding and market manipulation have triggered reforms via the congestion management process, including the principle of use-it-or-lose-it-or sell-it to prevent hoarding. If capacity is congested, then the gas sector rules are designed to get capacity into the hands of those who want to use it, rather than using some clever algorithm that is only relevant very close to the time of the actual gas flow.

Network codes

The most important for gas are:

- *Congestion Management Principles* (CMP). This is the procedure for clawing back capacity that is not being used, and enabling its release to other market players that might want to flow gas.
- *Capacity Allocation Methodology* (CAM). This governs the way in which, whenever free capacity is available to the TSO, the TSO has to release it to the market. So capacity is clawed back by CMP and then put out into the market by CAM.
- *Balancing*. This sets out how users should be responsible for balancing, and introduces market-based balancing for day-ahead and intraday trading.

6. Conclusion

In setting the early target date of 2014 for 'completion of the internal energy market' – and getting successive EU summits to endorse that date – the European Commission had two hopes in mind.

One hope was that the integrationist drive (attempts to accelerate the coupling of markets, infrastructure, network codes, and trading practices) might prevent member states from feeling they need to concoct national capacity (as well as national renewable) schemes to maintain their energy security. From the Commission energy directorate's viewpoint, such national schemes seriously threaten the geographical unity of the internal energy market, in the creation of which it has invested so much time and effort. Moreover, since these national schemes concern renewables, or the consequence of renewables, they add to the irritation of those who, like EU energy commissioner Günther Oettinger, currently feel that energy policy has come to be unduly subordinated to climate policy. Yet it was never plausible that there would be such a degree of cross-border network harmonization and expansion that member states would feel happy to rely primarily on each other for security of supply, and so minimize or forego national capacity schemes. Depending solely on foreigners, even close EU neighbours, to provide emergency back-up to keep the lights on is simply not good politics for national politicians.

The other hope is that advances towards a single energy market will bring down energy prices – if not in absolute terms then at least to a level below what they would otherwise be in the absence of cross-border competition in a liberalized market. Although this hope is a perennial one in Brussels, it is felt more acutely in times of recession, when households and companies tend to make price a priority over environmental considerations and therefore look for benefits from the EU single market primarily in terms of lower prices.

So, in an energy briefing paper for the May 2013 EU summit on energy, the Commission claimed that current EU energy policy was keeping prices in check. It argued that during the 2002–12 period, primary energy commodity prices (which are largely or wholly determined outside the EU) had increased on average by 14 per cent a year for oil, by almost 10 per cent a year for gas, and by 8 per cent a year for coal,

while the same figure for wholesale electricity prices in the EU was 3.4 per cent. At the level of wholesale prices, this is a perfectly good argument. The problem, however, is that the prices seen by households and most companies are retail end-user prices, which are increased and distorted by all manner of national taxes and regulations over which the Commission has little or no control. It is therefore difficult to make a politically effective argument for the price benefits of the single market. Moreover, such an argument involves gauging the counter-factual about what would have happened in the absence of an internal energy market or the attempt to create an internal energy market, which is impossible to prove.

Despite Brussels' frustrations in getting its price arguments across to the European public, recession has had the effect of returning the Commission energy directorate's prime focus to its traditional single market policies of liberalizing and creating competitive cross-border trade in energy. The Commission briefing to EU leaders was that 'the right policies are in place, but implementation is too slow'. But these policies were designed primarily for 'energy only' markets, where a generator's revenue depended entirely on the price he could get on the power exchange for his electricity. Today's markets are 'subsidy partly', where producers of renewable energy can rely on subsidies mainly or wholly independent of market price. The old order is changing. These days, downward pressure on prices is exerted less by market liberalization than by renewables surging on to the exchanges, and because these surges are intermittent, they no longer provide reliable price signals for investment.

This is no reason to abandon the goal of a unified European energy market. Market unification provides scale, and scale is the EU's main gift to its member states, in every sector of the economy. Scale has, to some extent, promoted wider competition, and through competition has come convergence in some regions on a more efficient price level. Climate goals and their consequences are proving disruptive in the electricity sector, but it is worth remembering that the EU has created more of a common electricity market template for its 28 member states than exists for the 50 US states. Scale also provides security for Europe, through diversity of energy source and supply, as well as a critical mass of low-carbon investment, and at least the potential to make a political difference in international climate negotiations.

But the single market mindset needs to take greater account of climate policy complexities. The Commission says it is already taking account of these complexities. In its March 2013 Green Paper on future energy and climate policy, it admitted that, in designing the 2009 energy and climate package, it 'underestimated' the impact of the 27 different national renewable support schemes, and 'did not address' the issue of the need for subsidized back-up for ever-larger renewable energy volumes. In an attempt to redress these omissions, the European Commission is aiming to produce guidelines in 2013 that would seek to 'Europeanize' national renewable and capacity support schemes and make them compatible with the single market.

However, if Brussels is to maintain an integrated energy and climate policy, it will have to come to a new view about the acceptable or necessary degree of public intervention in the single market. For the EU has arrived at a contradiction between its former policy of liberalizing and freeing Europe's energy market and its future ambition to de-carbonize its energy system. It is becoming increasingly obvious that companies will not invest in low-carbon generation unless member states, or the EU itself, either forces them to do so, or rewards them for doing so with subsidies, or does both. This is the inescapable conclusion that the UK has reached; this apostle of free energy markets is now proposing a series of state interventions to underpin low-carbon investment, both renewable and nuclear.

Up to now, liberalization has been considered the best means to achieve a unified EU energy market. If liberalization cannot deliver de-carbonization as well as integration, then policies will have to be modified to allow an increasing measure of state intervention. But who is the state in this case? It cannot be the EU. De-carbonization relates to altering the energy mix, which is a national prerogative. So if EU member states are to de-carbonize in an integrated manner, they will all have to intervene in the same way and to the same extent in their respective energy markets. Orchestrating similar state interventions will be harder than relying on the hidden hand of the market to be the conductor.

The policy strains examined in this paper underscore the difficulty for the EU, or its member governments, of balancing the three energy policy goals of competitiveness, security of supply, and decarbonization. Politicians, who are paid to worry about maintaining employment, keeping the lights on, and (in Europe) caring about climate

change, like to pretend that the three goals are perfectly compatible. They are not. No energy policy, except for actual energy saving, can serve all three goals equally. Trade-offs have to be made. The EU needs to re-think the trade-offs between its three energy policy goals, or at least whether its energy market can be better organized to accommodate these goals.

A hiatus in EU policy making approaches. In spring 2014 the current European Commission will come to the end of its mandate and the current European Parliament will be dissolved, and their successor bodies will only take office in autumn 2014. This creates a political pause. It could be used for much-needed reflection.

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