ASEAN ENERGY MARKET INTEGRATION (AEMI)

Energy Security and Connectivity:
The Nordic and European Union Approaches

FORUM PAPER

Energy Security and Energy Connectivity in the Context of ASEAN European Energy Market Integration

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Executive Summary

The first lesson drawn from the European Union energy market integration is the importance of an agreement among governments on the long-term objective to establish a market. Once all the member states had agreed on this objective in principle, the subsequent implementing decisions were taken by majority voting ("qualified majority"). The history of the EU shows that real progress can be made only when implementing decisions are taken by majority voting. But even then, trying to achieve a single integrated energy market for all 28 member states has proved to be too ambitious.

After 25 years of liberalisation, in 2014, the EU moved from a "single market" to a "regional markets" approach. Regional markets are now seen as stepping stones to an EU-wide energy market. There are presently four major regions in the EU: the Nordic region, including the Baltic republics; northwestern/Central Europe (Benelux, France, Germany, Austria and some neighbouring countries); Iberian island; and Southeast Europe. Some of these regions overlap, and opposition to market integration is best addressed by regionally focused approaches whereby concrete benefits in terms of network development, systems stability and resilience can be identified.

Region-wide analysis, e.g. on costs and benefits of cross-border integration, has been indispensable in terms of advancing projects and market integration since the benefits of integration are framed within a regional perspective. The analysis has been supported by governments and foundations, as well as interest groups that benefitted from regional integration. By now, most of the analysis in the EU has adopted an EU-wide or at least regional perspective.

A final lesson is to avoid designing the future based on the past. After 25 years, the EU energy market has started to work effectively, at least in the Nordic region and Western Europe. With the move towards decentralised power generation as a result of new political priorities, technological developments have also illustrated very clearly the need for a new way of regulating the market, planning grids, and cooperating between member states, not least on account of the intermittency of renewable energy.

Introduction

The creation of the internal market for energy has been one of the most ambitious yet controversial undertakings of the European Union (EU). Started as early as 1988, significant progress has been achieved, notably in the area of crude oil and oil products, public procurement and even the convergence of energy tax rates. More difficult proved to be the electricity and natural gas markets. More than 25 years after the objective to complete the internal electricity and gas markets was formulated, much work remains to be done. Within the Energy Union document (Egenhofer et al., 2014; European Commission, 2015a), the completion of internal electricity and gas markets is one of the five dimensions of the EU energy strategy. Energy Union can be seen as the final push to complete the internal energy market.

This article will take stock of the past and current efforts by the EU to liberalise electricity and gas markets. It will describe its motivation, the applied methods but also the specific EU institutional context. A particular focus will be on infrastructure policy and the new challenges which arise as a result of the EU and global decarbonisation agenda.

Energy in the EU

The EU Energy Situation

In 2013, according to the European Environment Agency (EEA), the total energy consumption of the EU was as follows: 33 per cent petroleum, 23 per cent natural gas, 17 per cent coal, 14 per cent nuclear, 12 per cent renewables and 1 per cent waste (European Commission, 2015b). The EU as a whole and all member states except Denmark are net energy importers. In 2012, 53 per cent of the EU's energy needs were imported. This represents a 40 per cent increase since the 1980s when liberalisation started. The dependency rate is highest for crude oil with 88 per cent, followed by natural gas (66 per cent) and coal (42 per cent). Russia tops the table as the biggest supplier for all three fuels. Natural gas imports are highly concentrated; more than three-quarters (77 per cent) of the EU-28's imports of natural gas in 2012 came from Russia, Norway or Algeria. Most of the Central and Eastern European member states depend on Russia as the main or in some cases, sole supplier for natural gas. Overall the Russian share of EU imports is typically somewhat above 30 per cent with recently strong yearly variations as a result of market dynamics and weather variations.[1]

As a net importer, the EU has traditionally attached high importance to energy demand management through energy efficiency and conservation. High energy prices compared to other regions have made Europe's industry among the least energy-intensive as a result of specialisation in non-energy-intensive goods and energy-efficient production. High European energy prices were offset by high efficiency and specialisation in higher value-added goods resulting in moderate energy costs, keeping the European industry competitive (European Commission, 2014).

Greenhouse gas emissions in 2012 were down by 19 per cent compared to 1990, keeping the EU on track to meet its 20 per cent reduction objective by 2020. Although reductions are a result of policies, they have been "helped" by the fall of economic activity following the world economic crisis. There is also some windfall effect as a result of the economic contraction of the former GDR and the member states from Central and Eastern Europe. Due to an effective policy, renewables have been growing very fast and are expected to reach the target of 20 per cent in total primary energy in 2020. In 2013, it has been above 13 per cent of total final energy consumption, up from 8 per cent in 2007.

[1] Up to the subsequent Russia–Ukraine crises, Russia has been a reliable and relatively cheap supplier, causing few fears on security of supply. Except for oil during the oil crises, supply concerns or disruptions have been related to domestic events, e.g. strikes of coal miners, blockades of refineries by truckers, electricity blackouts and brownouts as a result of system failure. With the first Russia–Ukraine crisis in 2006, however, gas supply disruptions have become a concern for the EU and its member states.

EU Energy Policy

EU energy policy, as most EU policies, features supranational as well as intergovernmental elements, depending on the specific area of action. For example, at the onset of the "European project", there was a common "EU policy" for coal (European Coal and Steel Community "ECSC") and nuclear energy (Euratom), while later on and outside these two sectors energy policies have largely been confined to essentially voluntary intergovernmental cooperation. Such voluntary cooperation typically means that decisions are based on the lowest common denominator, except in times of crisis. As a result, typical energy policy areas such as choices about the fuel mix and (by extension) geopolitics are generally left to member states. This has resulted in a very low degree of convergence between the fuel mixes, notably in the power sector, and to a varying degree of diversification of the gas import portfolio.

In this situation, policy at the EU level has mainly focused on building an internal market for electricity and gas and horizontal measures to moderate demand, and to promote indigenous energy sources, including renewables. In the domain of the internal market, the EU decides by majority voting. The EU's Lisbon Treaty, which came into force in 2009, has not affected the constitutional situation as it yet again confirmed member states' relative freedom of choice of their energy mix.

In addition to the internal market, energy policy initiatives have often been driven by climate and environmental concerns, and under different constitutional situations. Since the 1980s, the EU has had significant legal authority, notably the possibility to take decisions by (qualified) majority vote. Many of the EU's energy policy decisions, including those on energy efficiency and renewable energy, have a legal basis stemming from environment and climate change commitments. Pursuing energy policy goals via the environment has been facilitated by the EU-wide consensus on the importance attached to addressing climate change preceding the 1997 Kyoto Protocol. This is evidenced in the EU's so-called 2007–09 Energy and Climate Change Package,[2] which established a 20 per cent greenhouse gas reduction target, a 20 per cent energy efficiency improvement, and a 20 per cent renewables production goal—all to be met by 2020. These targets are currently being updated for the 2020–30 period. On 23–24 October 2014, the European Council decided on a new set of targets for 2030 ("2030 Framework for Climate and Energy Policy"), including a 40 per cent greenhouse gas reduction, a minimum 27 per cent renewables, and a minimum 27 per cent efficiency target, as well as an interconnector target in the meantime.[3]

[2] Often also referred to as 20-20-20 by 2020 Package.

[3] The European Council of October 2014 agreed to arrive at a 15 per cent interconnection target, meaning that each member state should have interconnections to the tune of 15 per cent of electricity consumption.

The EU's Internal Market for Electricity and Gas: Motivation and Method

There are legal/constitutional and economic drivers behind the creation of an internal energy market, notably for electricity and gas. Setting up an internal market to guarantee the freedom of movement for goods, services, capital and persons is one of the most fundamental objectives of the EU, and therefore is a legal obligation under the Treaty.

The economic justification for the internal electricity and gas market is based on two arguments: (i) increased competition in order to lower costs; and (ii) scale to enhance security of supply. The European Commission has frequently argued that a unified EU electricity and gas market would be intrinsically more secure than the individual member countries' markets. A larger market—served by wider and well-interconnected networks, and which receives electricity or gas supplies from a larger number of actors—may be expected to be more stable than a combination of national markets, and often, small countries. A resilient market also fosters solidarity among EU member states, and solidarity has been a guiding principle of the Lisbon Treaty, effected in 2009.[4] An integrated market is more efficient in allocating resources across Europe than strictly nationally organised, and often small markets. It would provide a pan-European signal to promote investment in electricity and gas infrastructure.

Beginnings

Although the creation of an internal market is one of the tools for achieving European integration,[5] progress was slow for many years. A fundamental change occurred in the 1980s, with a reform of the EU Treaty through the so-called Single European Act that came into force in 1986. This was followed by the so-called Delors White Paper, which set out an ambitious programme to successfully establish the single or internal market by 1992. However, energy was neither part of the Single European Act, nor the White Paper. It was only as late as 1988 that the creation of an internal energy market was actively pursued after it became evident that energy markets were deeply affected by internal market legislation. Key areas of legislation included public procurement, which, despite a delay, soon had to be applied to the energy sector. Tax harmonisation and environment legislation also affected the sector. But the most important was the active application of the hitherto dormant competition rules (e.g. the then Art. 90 and competition rules 85, 86) to utilities for the first time. Nevertheless, it took nine years, until 1996, to reach an agreement on electricity. Not surprisingly, the resulting Directive (96/92/EC) remained cautious, and competition was slow to take off.

[4] In the absence of an integrated gas market, each member state—many of them small—was responsible for signing gas import contracts, often from a single supplier, e.g. Gazprom. In an integrated market where gas flows freely, imports are contracted by pan-European companies, which serve the whole EU market. 80 per cent of the gas is traded at gas hubs.

[5] The others have been economic tools, the Monetary Union, and common policies and activities.

The framework set by the first electricity and gas directives of 1996 and 1998 (European Union, 1996, 1998) fixed a minimum level of competition at member state level by way of agreed common rules, while progressively bringing down barriers to cross-border trade. It was expected that the cross-border market dynamics would unleash competitive forces, which would quickly remove the last remaining barriers to the functioning of a fully competitive and integrated European market.

The first electricity directive of 1996 concentrated on full liberalisation of generation, and introduced a six-year phased-in freedom for all large and medium-sized companies to choose their supplier as well as the freedom to construct lines. Access to the grid was tackled by unbundling[6] the accounts of integrated companies, and by promulgating a number of different access rules to be implemented by member states that should guarantee non-discriminatory access. The 1998 gas directive chose the same approach in principle, but with two modifications: first, the transition period was to be 10 years to accommodate long-term investment needs; and second, the unbundling provisions were lighter to avoid undermining EU companies' bargaining powers with non-EU suppliers. The gas directive allowed each power generator to choose its own supplier.

While the first electricity and gas directives constituted considerable progress, many weaknesses persisted: a lack of effective, unrestricted and non-discriminatory third-party access to networks due to vertical integration, weak regulatory function, high and increasing concentration (and market power), limited or non-existent competition in the small consumer segment and, generally, insufficient liquidity in wholesale markets and response of prices to supply and demand conditions, including network capacity.

Many of the issues in the electricity markets could also be found in the gas markets. There were problems with access and high-access charges and the inadequate independence of transmission systems operators (TSOs). There were concerns about a lack of transparency over the publication of infrastructure capacity able to dispatch both cross-border and domestic transmission, and also in relation to capacity reservation procedures. Rules that governed network balancing were sometimes seen as being too stringent, to the point that they hindered the development of market competition, while at the same time they did not reflect the costs incurred. More generally, gas import levels and cross-border trade were seen as unsatisfactory, with the existing incumbents dominating domestic markets and wholesale prices. Gas trading hubs were slow to develop.

The "Third Package"

To address the shortcomings of the first and second package, the European Union adopted what became known as the Third Package.[7] It was adopted in 2009 and entered into force in 2011. It aimed to improve the functioning of the market and resolve

[6] Unbundling describes the separation of energy supply and generation from the operation of transmission networks.

[7] The Third Package comprises a number of Directives and Regulations; see https://ec.europa.eu/energy/en/topics/markets-and-consumers/market-legislation.

structural problems, notably related to unbundling and the independence and capacity of the regulator. Practically, it consisted of:

- Fully unbundling energy suppliers from network operators
- Strengthening the independence of regulators
- Establishing the Agency for the Cooperation of Energy Regulators (ACER)
- Improving cross-border cooperation between transmission system operators and the creation of European Networks of Transmission System Operators (ENTSO-E and ENTSO-G)
- Increased transparency in retail markets to benefit consumers[8]

Most significant were the rules on unbundling, regulatory agencies and cooperation of TSOs. The Directive foresees either full ownership unbundling in cases of integrated companies, or the creation of an independent System Operator where all important decisions are taken independently of the parent company.

Independence of regulators from both industry interests and the government should, from now on, be guaranteed by creating legal entities with sufficient funds provided by national governments and authority over their budgets. Following the Third Package, regulators can issue binding decisions to companies at the member state level and impose penalties in cases of non-compliance. Regulators now have far-reaching access to data from generators, network operators and other companies. Finally, regulators from different EU countries are asked to cooperate with one another to promote competition, the opening-up of the market, and an efficient and secure energy network system. However, this cooperation has been slow to develop.

In order to boost cooperation between different national regulators, the EU established the independent Agency for the Cooperation of Energy Regulators (ACER), located in Ljubljana, Slovenia. It is not comparable to a national regulator, e.g. in the UK. Instead, it should be seen as an attempt to bundle all competencies related to cross-border trade, which is in EU philosophy an original EU task. All other regulatory competencies remain with national regulators, in line with the subsidiary principle.[9] By Europeanising cross-border competencies within one agency, the EU has attempted to: i) reinforce the European Commission's role as the responsible body for undertaking negotiations with third countries; ii) affirm the independence of regulatory authorities from both the European Commission and member states; iii) reduce the complexity of

[8] For a more detailed analysis, see, for example, the Florence School of Regulation, at http://fsr-encyclopedia.eui.eu/the-third-energy-package-2009/.

[9] The subsidiarity principle stipulates that the EU action is appropriate only if an objective cannot be sufficiently achieved by member states. In addition, EU intervention must be proportional to the objective to be achieved.

the current system; and iv) bundle technical expertise within EU bodies. The main advantage is that it could be implemented within the then existing Treaty as well as the then forthcoming Lisbon Treaty. The EU Treaties require that the delegation of powers to independent agencies must be limited to implementing powers clearly defined and entirely supervised by the delegating institution, on the basis of specific and objective criteria. Put differently, this means that delegation cannot concern discretionary powers involving a margin of political judgement, unless they are set up by the EU Treaty itself, by "quasi constitutional law" itself.

Given that networks have been and still are developed according to national, member states' interests, a particular focus has been cooperation and integration of (national) TSOs. This is attempted through the creation of the European Networks of Transmission Systems Operators, for both electricity and gas: ENTSO-E and ENTSO-G. Their task is to develop standards and draft network codes, later to be formally adopted in EU legislative processes, to help harmonise the flow of electricity and gas across different transmission systems as well as to coordinate the planning of new network investments and monitor the development of new transmission capabilities. This includes publishing a Europe-wide 10-year investment plan to identify investment gaps every two years.

This focus on TSOs has led to a surprising development: the creation of multinational network companies, such as Elia and Tennet, which own assets in several member states. On the downside, there is an unresolved conflict of interests, as ENTSO-E and ENTSO-G are responsible for network planning, while at the same time, their member companies will build and operate the assets they have been planning.

A notable development is that small consumers, such as households, have shown very little interest in retail market liberalisation. The financial savings achieved by changing suppliers are generally seen as too small and the transactions costs too high to motivate consumers to switch.

Coupling National Markets to Create a Single EU Market

Cross-border cooperation and competition is most advanced in the power sector. The EU blueprint for creating an internal electricity market foresees that national power markets should be coupled at the wholesale level. Implicitly, this means that the EU is pursuing a zonal pricing approach, not a nodal pricing approach. In most cases, price zones are currently defined by national borders, with some notable exceptions. In the Nordic markets and in Italy, there are sub-zones to reflect internal (domestic) grid congestion, while Germany, Austria and Luxembourg represent a unified market with a single wholesale electricity price for these three countries.

Market coupling has been successfully implemented for day-ahead markets, while much work remains to be done for intra-day and balancing power markets. Essentially, coupling means that generators do not have to decide whether to offer their production capacity to the domestic or a neighbouring market. Instead, electricity should freely flow from regions with high prices to regions with low prices. To this end, the various national market operators (power exchanges) combine all demand orders and supply offers. Afterwards, the available cross-border transmission capacity is allocated in such a way that the overall costs to consumers are minimised. In this way, physical transmission rights are allocated implicitly. As of June 2015, this approach has been implemented in most EU member states.

In the current framework, transmission rights must be used day-ahead or will otherwise be released to the day-ahead market-coupling algorithm ("use-it-or-sell-it" principle). It is currently not possible to keep these transmission rights for transactions in the intra-day market, although for balancing purposes they may be reserved under specific circumstances.[10] Moreover, bilateral agreements exist to allow for some cross-border intra-day trading.

It is also possible to obtain explicit long-term transmission rights. This can be useful to contract cross-border deliveries of electricity for a period longer than one day. Moreover, it gives market participants the possibility to hedge themselves against congestion costs. One shortcoming, however, is that transmission rights across national borders can only provide hedging opportunities between two price areas, and not on a regional or even EU level.

Implementation, Enforcement and Governance

As indicated earlier, the EU features supranational as well as intergovernmental elements, depending on the specific area. This is also true for energy. While energy policy in the narrow sense, e.g. choice of fuel mix, is a member state competence and therefore subject to unanimous decision, other areas such as the internal market (including energy) or the environment (including climate change) are subject to qualified majority voting. While voting is very seldom used, the very possibility of a country being outvoted has a disciplining effect, and countries are more open to compromise. In areas where unanimity is required, controversial decisions tend to be adopted only in times of crises, such as that involving the Euro.

Nevertheless, there is an implicit understanding that the EU does not adopt measures which would put a member state government under pressure. Therefore, there is significant opportunity for member states to bargain very hard. Very often, this results in transition periods, differing options being offered to member states, or straightforward exemptions. In reality, this means that a particular policy issue is subject to recurrent changes. In the field of the internal electricity and gas markets, there have been two changes to the original decisions, in the form of three packages—with a fourth one in the making.

When it comes to enforcement, the situation is different. If member states do not implement legislation which has been adopted, the European Commission can bring them to court within four months. The difficulty is that in many cases a possible breach of EU law can be hard to identify. Given the fact that member states have very different legal systems and traditions, let alone more than 20 official languages, the EU typically leaves considerable discretion to member states when implementing legislation.

[10] The network code on "electricity balancing" allows for reserving transmission capacity for balancing markets subject to cost–benefit analysis.

In this respect, competition law, which covers state aid such as illegal subsidies and anti-trust measures, is different. Here, enforcement is entrusted to the European Commission. In this field, the European Commission can act without member states' consent.

Infrastructure Policy

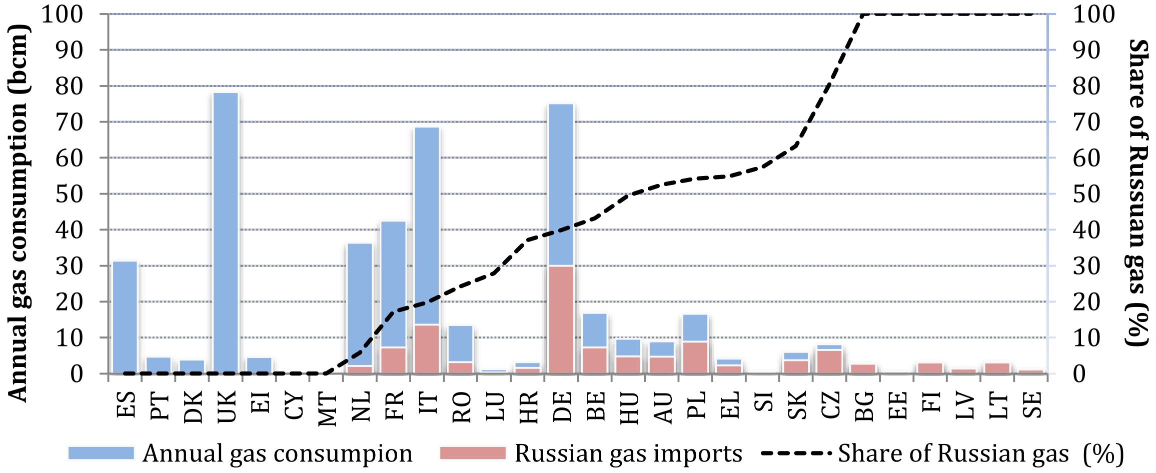
The European Commission estimates that €200 billion needs to be invested for both electricity and gas by the year 2020 to successfully establish the internal market for electricity and gas, and also to guarantee security of supply. Planning is based on the rolling so-called "10-Year Network Development Plan" (10YNDP) compiled by the EU electricity and gas TSO associations, ENTSO-E and ENTSO-G, respectively. Execution of the projects is done by member states according to national laws and regulations such as those relating to permitting and other issues. Financing in most cases is private, although supported by member state funds. The EU contribution is small and is currently limited to roughly 3 per cent of the total amount required.

A major shortcoming is the fact that the 10-Year Network Development Plans are largely a bottom-up exercise—whereby member states, and often regional and local governments, promote their own priorities based on their national or sub-national needs, interests and politics, with limited consideration for the EU perspective or the market. This is aggravated by the unresolved conflicts of interests between the TSOs, which are at the same time responsible for network planning, as well as building and operating their upcoming projects. Further, most European member states tend to be densely populated, and thus face difficulties concerning the social acceptability of infrastructure projects. This is generally seen as the biggest obstacle to the construction of new electricity and gas infrastructure.

As a result, natural gas markets and infrastructure are unequally developed within different regions of the EU, often depending on historical developments. For instance, the markets of the Baltic States are isolated and not connected to gas hubs in Central Western Europe,[11] which are generally considered competitive and liquid markets. The size of these Central Western European markets—more than 80 per cent of total EU gas consumption—also makes it easier to attract new suppliers of natural gas. The situation in southeastern Europe is similar to the Baltic States: connectivity to other parts of Europe remains low, thus forcing Romania and Bulgaria, for example, to rely on (limited) domestic production and imports from Russia. These states are also the most vulnerable to supply disruptions. In 2012, these five member states were 100 per cent dependent on natural gas imports from Russia: Latvia, Lithuania, Estonia, Bulgaria and Finland (see Figure 1).

[11] The central Western Europe electricity market region comprises Austria, Belgium, France, Germany, Luxembourg, the Netherlands and Switzerland.

Figure 1. Russian Gas in the Total Gas Consumption of the EU-28 (2012 data)



Source: Authors' own data, based on data from BP, the U.S. Energy Information Administration, and the International Energy Agency

Power markets, as with gas markets, face similar challenges of fragmentation. As in the gas sector, missing infrastructure is a key reason for fragmentation in the power market. Increasingly, there is a need for new electricity interconnectors to accommodate an increasing level of intermittent renewables, but progress is very slow.

New Challenges

The EU electricity market has been developed as a so-called energy market only (EOM), with no separate payments for capacity availability. At the core is the day-ahead market, which produces a uniform, non-discriminatory market price for each hour of the day as a result of the intersection of all offers and bids. This price is set by the variable production costs of the marginal power plant—the last power plant needed to satisfy electricity demand. All generators receive the same price irrespective of their variable production costs. As a result, generation units with variable production costs below the market price receive a so-called "infra-marginal rent". This margin— typically referred to as the gross margin—is used to cover fixed operations and maintenance (O&M) costs, as well as to recover investment costs. Thus, availability is implicitly remunerated through infra-marginal rents.

If market prices were always equal to the variable production costs of the marginal plant, this plant would not even be able to cover its fixed O&M costs, let alone recover its investment costs. This is why so-called "scarcity prices" are required to let an energy-only market function properly.[12] Such price increases are expected to occur when supply struggles to meet demand (e.g. when consumption peaks), when production from intermittent renewable sources is low, or when there are large, rapid

[12] It can be shown that such scarcity prices are needed not just for the marginal production unit but for all units in order to recover fixed and investment costs. Scarcity prices can only occur if there is no restriction on the bid price. This means generators must be allowed to bid above marginal costs. At the same time, competition authorities must ensure this does not lead to strategic bidding, i.e. exercising market power (see Joskow, 2007).

swings in demand or supply. During these hours, the price would rise above variable production costs of the marginal plant and thus offer a so-called "scarcity rent" to all resources in the market. These additional revenues are needed to fully recover both fixed O&M and investment costs.

An energy-only market attracts investment in new capacity, therefore, through either direct or indirect reliance[13] on scarcity prices. Unexpected policy interventions, erroneous demand expectations, and long lead times for planning and building new capacity tend to lead to boom and bust cycles, with times of overcapacity alternating with times of scarce capacity. When there is overcapacity, scarcity prices are not going to occur, simply because supply is always well above demand, which signals that there is no need for new capacity.[14]

Renewable Energy

The very rapid build-up of renewable generation in final energy consumption to 20 and 27 per cent in 2020 and 2030, respectively[15] has created a situation where price signals play an increasingly smaller role. Renewable energy investment has mostly not been triggered by wholesale price signals based on internal energy market regulation combined with the carbon price signal from the European Emissions Trading System (ETS).[16] To achieve this target, EU member states have primarily relied on dedicated policy instruments to support the deployment of renewables, often feed-in tariffs under long-term contracts. There are two effects of using dedicated support policies.

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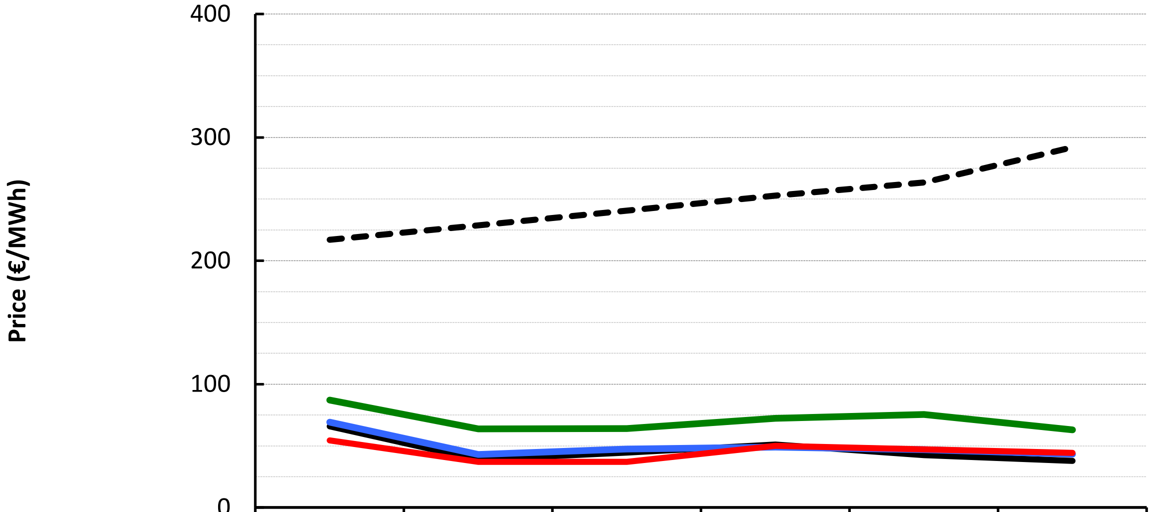
[13] Indirect reliance refers to market participants entering into commercial arrangements with one another so as to hedge their exposure to the price and volume risk.

[14] Scarcity pricing is also suppressed or distorted in energy markets, e.g. through direct public interventions or system operators (partly) socialising balancing costs.

[15] The 20 per cent renewables target of total primary energy is likely achievable, but it means that within a short period renewables will constitute some 30–35 per cent of total electricity production. This situation is likely to continue as the EU has agreed to move to a minimum level of 27 per cent renewables in total primary energy production, which would translate somewhere between 40–50 per cent of renewable energy in the electricity market.

[16] Carbon prices under the ETS have been below 10 EUR per tonne of CO_2 and the ETS, and there is little expectation that this situation will change within the next 10 years.

Figure 2. Retail (Household) and Wholesale Power Prices in Germany (DE), France (FR), Spain (ES) and Italy (IT), 2008–13



	2008	2009	2010	2011	2012	2013
DE, retail	217.2	228.8	240.7	253.0	263.6	292.0
DE, wholesale	65.8	38.9	44.5	51.1	42.6	37.8
FR, wholesale	69.2	43.0	47.5	48.9	46.9	43.2
ES, wholesale	54.4	37.0	37.0	49.9	47.2	44.3
IT, wholesale	87.0	63.7	64.1	72.2	75.5	63.0

DE: Germany; FR: France; ES: Spain; IT: Italy
Source: Eurostat and ACER (Agency for the Cooperation of Energy Regulators)

First, these policy instruments reduce the demand for electricity generated from conventional sources, resulting in falling wholesale prices, and at times even negative prices. Adding supply to an already saturated system will further depress wholesale power prices.

Second, there is more fluctuation in demand for electricity from conventional sources, because renewable generation depends to some extent on weather conditions. The reduced hours of operation of conventional power plants create a need for a different mix of conventional generation technologies, as these do not just differ in their variable production costs but also in their fixed and investment costs. So-called "base-load" capacity is used to cover the minimum continuous level of electricity demand, as it has relatively low variable but high fixed and investment costs. Consequently, when hours of operation diminish, some base-load is expected to be replaced with capacity that has lower fixed costs—natural gas, for example.

The business case for peak-load is challenging because investment costs have to be recovered from a low number of operating hours. What changes with renewables is that: (i) more of these units will be needed; and (ii) the exact amount required is subject to greater uncertainty today due to the weather-dependent availability of renewables. This comes at a time when Europe seems to be entering a situation where overall demand for electricity (even before allowing for renewables) is not growing, and in fact may decline, unless other sectors such as heating or transport are electrified. This represents a radical change for the industry, which for over 100 years was used to steady growth (Genoese and Egenhofer, 2015a).

Reforming the Market

The policy-driven rapid expansion of renewable energy has triggered a debate on a comprehensive reform of the EU electricity markets, or as it is called in EU jargon, "market design" (Redl et al., 2015; Genoese and Egenhofer 2015b; Weale, 2015). The European Commission has launched a stakeholder consultation which closed in early October 2015.[17] The discussion intensified in autumn 2015 with a legislative proposal to be expected during the course of 2016.

In the meantime, member states have taken action and introduced new mechanisms to deal with an explicit remuneration for being available or delivering energy in times of system stress in the form of capacity mechanisms. The objective is to ensure parallel streams of revenue to allow the recovery of that portion of their fixed costs that is not recoverable in energy and balancing markets, while also reducing the dependency on uncertain scarcity revenues. Capacity mechanisms have been implemented or are in the process of being implemented in several EU member states, including France, Germany,[18] Italy, Belgium and the UK. These mechansims also have a long history in South America and in the US,[19] where several states rely on both energy and capacity markets.

Low-Carbon Investment

A largely carbon-free power sector by 2050[20] will require considerable investment, some of which will replace carbon-intensive capacity with more flexible, less carbon-intensive forms of power generation. With the drive towards a low-carbon economy, the electricity market will need to make a positive contribution to the successful delivery of these new policy objectives. It is necessary to understand how the low-carbon economy will be brought about, notably what market rules are required and whether there is a need to adapt the current framework.

Given the weakness of the wholesale price signal, the EU and its member states are discussing the role of governments in providing such a long-term price signal. A first element is a strengthening of the EU ETS in order to provide a long-term price signal for carbon allowances, which would first serve as a market-exit signal for carbon-intensive capacity. In addition, other ideas are currently under discussion. These include:

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[17] See https://ec.europa.eu/energy/en/consultations/public-consultation-new-energy-market-design.

[18] Strictly speaking, there is currently no capacity mechanism in place in Germany. Yet there is a so-called "grid reserve" (*Netzreserve*) to ensure that TSOs have access to sufficient "re-dispatch" capacity. Re-dispatch refers to a measure to resolve internal grid congestion. Since it provides a capacity-based revenue stream for generators, it acts as a kind of de facto capacity mechanism.

[19] See, for example, Hogan (2015).

[20] According to the EU Energy Roadmap, every decarbonisation scenario will feature a high share of renewables, i.e. at least 64 per cent in 2050 (European Commission, 2011)

- Contract-for-Difference related to the electricity price
- Contract-for-Difference related to the carbon price
- So-called reliability options
- Capacity auctions

From an EU perspective, these will still need to be tested against their internal market compatibility.

Conclusions

Although the creation of an integrated electricity and gas market is a legal obligation under the EU Treaty, it has been slow to take off. Following several rounds of legislation, however, the EU is getting close to a well-functioning, competitive electricity and gas markets. All electricity markets are or soon will be coupled, whereby electricity can freely flow across the EU. 80 per cent of all natural gas is traded on gas hubs, with gas-to-gas competition. The remaining 20 per cent is located in Central and Eastern Europe, in countries late to join the EU and which also embarked on liberalisation somewhat later. A major shortcoming remains the lack of sufficient cross-border infrastructure. Reasons are that infrastructure still remains to be planned and built according to national interests, and also in the face of public opposition.

The rapid investment in renewable energy supported by dedicated support mechanisms, such as long-term feed-in tariffs, has in recent years led to a situation where wholesale prices do not allow generators to be remunerated for generating electricity. This situation is likely to continue since there is a political agreement and a target to continue building massive new renewable energy capacity. This is why member states increasingly deviate from an energy market only and complement it with a separate capacity remuneration market. Looking ahead, the major question to ask is: how to generate investment signals and, in addition, give signals that the investment becomes low-carbon. This is still currently under discussion, but the likely result is a fundamental transformation of the way the EU electricity markets work today.

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