CENTRE ON REGULATION IN EUROPE

Europe's wholesale electricity markets: future regulatory perspectives and challenges

Policy Paper

edited by Professor Catherine Waddams (CERRE & ESRC Centre for Competition Policy, University of East Anglia)

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CERRE's added value is based on:

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This policy paper has been developed within the framework of the CERRE Executive Seminar of 19 June 2013, which received the financial support of CERRE members ELIA and CREG. As provided for in the association's by-laws, this paper has, however, been prepared with complete academic independence. The contents and opinions expressed reflect only the authors' views and in no way bind either the sponsors or any other member of CERRE.

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About the authors

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Her research interests are in the area of Industrial Organization, and she has published widely on privatization, regulation and the introduction of competition, especially in energy markets. She is particularly interested in the distributional impact of regulatory reform, and consumer choice in newly opened markets, both in the UK and elsewhere.

Catherine Waddams has worked with the World Bank, the OECD and sector regulators in the UK and overseas. She was a part time reporting member of the UK Competition Commission from 2001-2009 and is a non-executive Director of The Water Services Regulation Authority (Ofwat), the economic regulator of the water and sewerage sectors in England and Wales, and a member of the expert consumer group of the UK Office of the Rail Regulator.

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He has worked in power system dynamic analysis, monitoring and diagnosis of power system devices and systems, intelligent computer design of industrial systems, planning and operation of electric generation and networks, regulation and restructuring of the power industry, and sustainability of national and global energy models. He has been a consultant for governmental agencies and electric utilities in more than 30 countries.

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Professor Richard Green is the Alan and Sabine Howard Professor of Sustainable Energy Business at Imperial College Business School. He started his career in the Department of Applied Economics at the University of Cambridge, and has held chairs at the University of Hull and the University of Birmingham. An economist, his work concerns competition and regulation in the electricity industry; particularly in the wholesale markets where generators sell power to retailers. Much of his recent work concerns the implications of a large increase in the proportion of electricity coming from renewable generators. He has been a specialist advisor to select committees from both Houses of Parliament, and held visiting positions at the World Bank, the University of California Energy Institute and the Massachusetts Institute of Technology.

1. Introduction

The executive seminar in June brought together the three interesting papers presented here, and stimulated discussion across the topics. The issues discussed, some of which resulted in more challenging questions than clear answers, are incorporated into the individual papers. The role of this introduction is to identify common themes and potential ways forward in the area of wholesale energy markets at a time when this is of crucial importance both at European Union and Member State level.

- Both the papers and the discussion emphasised underlying support for the market process wherever it could be used, and so a focus on identifying market failures where intervention might be appropriate.

- Energy markets pose a challenge because of the long term nature of investment, which do not necessarily yield a positive net worth in a short term Cost Benefit Analysis. It is sometimes difficult for regulators and market designers to take the long term view when the political horizon can be so much shorter.

- Increasing complexity in markets raises their costs, and these higher costs are likely to be borne by consumers, adding to the political pressure in this area. There may be particular difficulties for vulnerable consumers, particularly those who have high energy expenditure, but also for general competitiveness if non-residential energy prices increase.

- There is real danger of political and regulatory failure, resulting in a dangerous vicious spiral of intervention which causes unanticipated adverse consequences, which then require further intervention to correct them. Such a process is likely to result in higher costs for customers and consumers. This process explains a general lack of enthusiasm for capacity mechanisms.

In what circumstances is a central solution appropriate, say at EU level, and where is a disaggregated market solution better? How far may national interests conflict with European agenda? Such tensions are likely to lead to State Aids issues in many Member States, as they try to reconcile the interests of their own populations with those of the EU as a whole.

Each paper is self-contained, with excellent summaries both of the original arguments and of the consequent discussion, but some features of each contribute particularly to the overall theme.

Smart technology

The basic definition of smart technology is still unclear – a "smart meter" can mean many things, and what they can deliver clearly depends on their intrinsic characteristics. Sometimes the phrase is used to describe a meter which is able to convey 'dumb' consumption information from individual meters to a central billing point. Or they could be capable of much more sophisticated two way communication with both customers and appliances. Consequently much of the debate depends on their definition.

How quickly should smart technology be deployed? There is a clear option value in waiting to gain more benefits as technology develops, but conversely there are economies of scope from rolling such meters out across several sectors at once, which suggests moving sooner rather than later. Different market participants may also perceive the benefits very differently – consumers may see the benefits of greater control and information, while providers may focus on saved billing costs. These different perspectives indicate that expectations must be carefully managed. As with all new technologies there is the question of whether regulators or governments should pick winners, risking the wrong choice, or allow the market to roll out a number of technologies which may be mutually inconsistent and may, more crucially, hinder competition in related markets by adding to costs of switching. Institutions are slow to resolve these issues, particularly at international level.

Perhaps most important is the response of the consumers: will smart meters necessarily generate smart consumers? If they do not understand the messages which are being transmitted to them, the opportunities for demand response will clearly be severely limited. A CERRE report on smart meters, to be published in early 2014, will explore this issue further.

Generation capacity adequacy

One mystery about capacity support was why so many such schemes existed, given the lack enthusiasm for the concept among many experts, including those participating in the CERRE seminar. While there are clearly potential market failures as described above, the discussion focused more on regulatory failure, with much more interest in using mechanisms to complement the market than to substitute for it. The strength of potential interventions to kill or severely impair the market was widely recognised, and legal failures might often exacerbate the damage. If no market failure exists, then intervention would generally be ruled out as constituting state aids.

Generation mix

The importance of interdependence within Europe was emphasised with respect to generation mix, where there are enormous potential cost savings from allowing different technologies to be exploited through energy trading. The rapid increase in the use of renewables made this more relevant, as the trading of different renewable sourced power in Nord Pool has demonstrated. However such international arrangements required trust between countries, and an acceptance that such connections might raise prices locally, even though there were benefits for consumers as a whole. Of course markets should work well in theory: but, like chains, they are only as strong as their weakest part, and some doubt was expressed about whether the practice lived up to the theory.

Conclusion

A number of issues emerged from the discussion across all of the sessions. One was the crucial role of uncertainty in this market, the importance of trust and the need for stability. Above all, policy coherence was required, including a delicate balance between the sovereignty of Member States and reducing the costs for European consumers as a whole. Such a dilemma should be soluble through allowing trading of benefits, but how could such arrangements be credibly made and adhered to, in the face of the emotive and politically damaging possibility of the 'lights going out'? Energy is not necessarily unique in this regard: some similar issues may arise in transport, with a possibility for inter-sector learning.

The power of markets was evident – both when they work and when they do not, and co-ordination and central management can be very costly. Adequate transmission assets and better use of existing transmission lines could provide considerable benefits. The papers and the seminar underlined the enormous beneficial potential for an EU wide model, and the corresponding potential losses if the opportunity for co-ordination is missed.

2. Smart technology and demand response

by **Dr Guido Cervigni**

2. 1. Introduction

The deployment of smart metering technologies in network industries such as water, electricity and gas is taking place or is being discussed in many European countries. On the one hand, this is the result of technological developments on solid-state sensor technology and digital data processing and communication which make it possible to deliver more advanced metering services on a large scale. On the other hand, European policies on sustainability and on the single energy market consider smart metering as a crucial enabler of changes in consumers' demand for energy.

The issues to be discussed in the first panel on Smart technology and demand response of the forthcoming CERRE Executive Seminar on *Europe's wholesale electricity markets: Future regulatory perspectives and challenges*, relate to:

a) the expected costs and benefits of large scale deployment of smart meters in the electricity and natural gas sector;

b) the characteristics of the organizational model for metering activities that appears most suitable to achieve the objectives attached to the deployment of smart meters at minimum cost;

c) identification of those aspects of the legal and regulatory environment that might need to be updated in order to maximize the benefits of the smart metering system.

This paper provides, essentially in the form of questions, an outline of the above mentioned topics.

2. 2. Benefits and costs expected from the deployment of smart metering

2.2.1. Expected benefits

Smart-meters are expected to deliver benefits in the following areas.

Retail services

- More accurate billing, as smart meters eliminate the need for bills based on estimated consumptions;
- Easier contractual changes, as some changes with smart-meters do not require accessing customers' premises (e.g. deactivation/reactivation of supply, change in the maximum allowed withdrawal, implementation of pre-payment);
- Access to a wider range of offers (including time-of-use tariffs, real time pricing, etc.) and possibility to implement (bill reducing) load and/or micro generation management;
- Easier supplier switch, as the meter reading at the time of the switch can be known precisely.

Retail costs

Some retail costs are expected to be reduced, thanks to smart-meters, for example because of:

- Fewer bill complaints to manage, due to the more accurate billing;
- Quicker and cheaper disconnection/reconnection of consumers not paying their bills.

Electricity pricing

Conventional consumers, who have no smart meters, are charged on the basis of total their total consumption over the period between two meter readings, irrespective of the time-pattern of consumption during the billing period.

A smart meter allows assessing the cost caused to the system by the consumer's power withdrawal at each time and – in a possible implementation – making this information available in real-time to the consumer (or the load serving entity). To the extent that the consumers' preferences are such that their consumption behaviour reacts to spot and real-time prices, the information collected and made available by the smart meters might:

- Move from higher-price hours to lower-price hours consumption by previously non smart-metered consumers;
- Make it possible for consumers to sell balancing services, by reducing withdrawals at short notice.

The development of demand-side price response is expected to:

- reduce the need for generation and transmission capacity, to the extent that the system load will be less peaky;
- reduce the need for operating reserve provided by fast-response relatively inefficient thermal units.

That should lead to a reduction in total generation and transmission cost, as well as total emissions. In addition, greater demand flexibility should reduce vulnerability to market power of the wholesale electricity market in tight supply conditions.

Energy conservation

Smart meters are expected to contribute to energy conservation by:

- enabling the development of smart-home solutions which lower consumption would be a by-product of;
- increasing consumer awareness of the cost and environmental impact of energy consumption.

Distribution service

Smart meters are expected to contribute to increasing the quality of the distribution service in areas such as:

- Identification of fault location;
- Timely identification of faults;
- Monitoring of service quality;
- Improved theft detection;
- Network planning, thanks to more extensive information on consumption patterns at the different locations provided by smart meters.

Embedded generation

Together with smart-grid measures, smart metering is expected to contribute to increase the distribution network's capacity to host renewable generators, even in the form of micro-generators located at the consumer's premises and integrated with the home's appliances.

2.2.2. Expected costs

Not much information is available on the cost of large scale deployment of smart metering system. That holds all the more for metering systems with the technical features necessary to reap all the benefits indicated in the previous section.

The UK estimates a cost of 11 billion euros to replace 53 million gas and electricity meters at 30 million consumers' premises by 2019. However, since a number of technical features of the future metering system are still being defined, this could impact the above cost assessment.

In all other European countries both the definition of the meters' requirements and the selection of the communication architecture are at a much earlier stage. This makes any cost estimate rather uncertain.

2. 3. Organisation of metering activities

2.3.1. Regulated monopoly vs. liberalised framework

In all EU member states - with the exception of the UK, the Netherlands and Germany - metering is regarded as part of the distribution activities. Distributors enjoy monopoly on metering activities and are regulated.

The relative merits of regulated vs. liberalised smart metering markets need to be assessed keeping into account the following factors:

- Complex standardisation issues at multiple interface points and process coordination issues need to addressed in order to obtain interoperability of smart metering systems; those issues may be exacerbated in a liberalised framework;
- It is possible that the cost minimizing architecture for smart metering systems entails that some components of the different utilities' metering systems (gas, electricity and water) be shared, making the monopoly regime less obvious;
- The weight of the data processing and communication component in the metering activity will increase in a smart metering environment; making metering and the distributors' core operations even less homogenous.

2. 4. Updates to the legal and regulatory framework

2.4.1. Regulatory coordination, privacy and data protection

So far metering activities have been generally subject to energy specific regulation. A plausible cost-minimizing technological scenario entails some metering infrastructure sharing among different industries. That would require coordination among different sector regulators.

Further, the quantity and possibly the variety of the information carried through the network used to link smart meters will expand. This could lead such network to be regarded as an electronic communications network and the services provided over it in relation to smart meters may be considered as electronic communications services. That would involve the telecommunication regulator in the metering industry.

2. 5. Demand response

Lack of demand response to prices in the short term is one of the main features making electricity different from other products. In particular, the insensitivity of a large share of demand to price, in the short-term, results in:

- the need for quantity rationing in case of scarcity and for a regulated price (or a price-cap) in scarcity hours;
- the extreme gap between (relatively low) prices in normal conditions and the rationing price in the event of scarcity.

Capacity adequacy concerns discussed in another session of the seminar, are rooted (also) in such an extreme optimal price pattern for electricity.

Greater price-responsiveness of demand would mitigate this feature of wholesale power markets. Further, they would contribute to the system's flexibility, necessary to offset at a reasonable cost the short term fluctuations of some renewable generators' production.

Currently only large consumers can be exposed to wholesale spot prices and therefore receive correct economic incentives to shape planned consumption consistently with the prices of electricity at the different times and to adjust consumption in response to price changes occurring as the time of delivery approaches.

An even smaller subset of consumers is capable to participate in real-time markets, i.e. to change withdrawals in response to the demand and supply conditions prevailing at the time of delivery. Further, typically the service rendered by these consumers to the system operator entails giving up consumption at very short notice when critical technical conditions occur, to a large extent irrespective of the price prevailing at the time of the interruption.

Large scale deployment of smart-metering systems is a necessary condition for enabling all consumers to plan and adjust power consumption in response to short-term prices. Depending on the kind of demand-side response that one intends to enable, different smart metering infrastructures and possibly additional measures have to be implemented. Relatively simple smart-meters enable day-ahead price-dependent load scheduling; more advanced communication infrastructures and electric appliances are needed to enable demand response to price (changes) closer to real-time.

In all events, demand response requires unbiased wholesale market prices for electricity, at all time-frames. In particular, regulatory provisions or market design flows that prevent prices to rise at time of scarcity may inhibit the development of (efficient) demand flexibility.

It remains to be seen whether the net benefits of providing flexibility is positive for a material share of the final consumers, so that a significant portion of the market's demand will become flexible.

3. Generation capacity adequacy: What economic rationale for support mechanisms?

by **Professor Ignacio J. Pérez-Arriaga**

3. 1. Terminology and problem definition

Generation capacity adequacy is one among several factors that contribute to the overall reliability performance of a power system. One has to realize that the actual physical supply of electricity to the end-consumers at a given moment in time is the outcome of a complex and interlinked set of actions, some of which were performed many years before, which jointly make possible that the right technologies and infrastructures of generation and networks have been developed and installed, provision of fuels have been contracted, hydro reservoirs have been properly managed, networks and power plants have been maintained correctly and at an adequate time, generators have been started-up and connected to the grid so that they were ready to function when needed, margins of operating reserves have been kept, and metering, control and system protections were functioning correctly.

Reliability can be defined[1] as "the degree to which the performance of the elements of the electrical system results in power being delivered to consumers within accepted standards and in the amount desired". Although the quality of the delivery of electricity only materializes in real time, as indicated before, its provision comprises a multiplicity of actions and measures that have to be performed in different time ranges from many years to seconds, by different agents –from investors to regulators or system operators and involving different types of technologies and equipment –generators of a diversity of technologies, transmission and distribution networks, control centers or the means of provision of primary fuels–. Therefore "reliability" has been precisely broken down into

[1] US National Electric Reliability Corporation.

its major components, in order to facilitate its understanding and to design proper technical procedures and regulatory measures.

From the "time" perspective one can distinguish four dimensions of reliability of electricity supply:

- **Security**, which is the readiness of existing and functioning generation and network capacity to respond in real time when they are needed to meet the actual demand. This is a short-term issue. Caring for system security is the main function of the System Operator, who sets at every moment the most adequate reserve margins for generation and network.
- **Firmness**, which is the availability to provide generation and network services "when needed", and depends on the short and medium term management of the already installed facilities: generator and network maintenance, fuel supply contracts, reservoir management, start-up schedules, etc. This is a short to mid-term issue. A flawed management of firmness may result in poor system security of supply, even if there is abundant installed capacity of generation and network.
- **Adequacy**, which means the existence of enough available capacity of generation and network, both installed and/or expected to be installed, to meet demand. This is a long-term issue.
- **Strategic energy policy**, which concerns the long-term availability of energy resources and infrastructures: long-term diversification of the fuel provision and the technology mix of generation, geopolitical considerations, future price evolution of fuels, potential environmental constraints, expected development of interconnections, etc. This is a long to very long-term issue.

This paper focuses on the *adequacy of generation* capacity, although *generation firmness* and *network issues* will have to be necessarily considered, since these three elements are inextricably coupled. In the context of the Internal Electricity Market (IEM), the major issue to be addressed here is whether there is a convincing justification for a regulatory intervention –the so called capacity mechanisms[2]– to achieve a satisfactory level of generation adequacy and firmness in a given power system, and whether the non-harmonized implementation of capacity mechanisms in the EU Member States might negatively affect the development of the IEM.

It has been recently claimed in numerous fora that **flexibility** should also be included as a new dimension of reliability, since it is a desirable characteristic of power systems, with a positive reliability impact in the presence of the actual or anticipated strong presence of intermittent sources (wind and solar) of electricity generation. Flexibility can be defined as the capability of a power system to adapt electricity production or consumption in response to variability, expected or otherwise, rapid and/or large, whatever the cause.

The need for a sufficiently flexible mix of generation technologies is not new in power systems: the variability of demand –with its daily, weekly and seasonal patterns– and the lack of storage capacity requires that every power system has *base-load* plants –typically inflexible, with low variable costs but high investment costs, like run-of-river hydro, nuclear and coal–, *intermediate* plants –typically combined cycle natural gas plants– and *peaking* plants that are very flexible and can start-up and change output very quickly –single cycle natural gas turbines–, with low investment costs but high variable costs–. Storage hydro, when available, provides extra operational flexibility. The strong presence of wind and solar requires a generation mix with different proportions of base-load, intermediate and peaking plants and also creates opportunities for innovation –like new natural gas fired plants that are both very efficient and very

[2] There is no common terminology for the regulatory instruments that support the investment of new generation capacity. This paper will refer to "capacity mechanisms", although the expression "Capacity remuneration mechanisms, or CRM" is frequently used.

flexible– and entry of new modes of contribution to flexibility: demand response, new storage technologies and better use of interconnections. This paper advocates that flexibility *should not be included* into the four dimensions of reliability of supply. However, it has to be carefully assessed that the market design –whether energy-only or with regulatory instruments to ensure sufficient security, firmness, adequacy and compliance with strategic energy policy of the generation mix– will result in a satisfactory level of flexibility for the conditions existing in the specific power system. Therefore the question remains whether there is the need to explicitly incentivize the "commodity" flexibility or not.

3. 2. Current concerns

Since the early times of power sector restructuring and liberalization, the ability of electricity markets to provide enough generation to reliably meet demand has been called into question. Mistrust of whether the electricity market, left to its own devices, can efficiently provide sufficient generation when needed has gradually but inexorably led to the implementation of additional regulatory mechanisms. This issue has increased in importance with the passing of time, and it is now present in the regulatory agendas of most power systems. While there is widespread consensus that security and strategic expansion policy require regulatory intervention, the debate on the need for regulatory instruments in generation adequacy and firmness remains open.

Recent efforts in European-wide regulation have focused on the shortest and longest-term issues. The *security* of the operation in wholesale electricity markets is currently a chief concern of the regulatory efforts of the European Commission, ACER, CEER and ENTSO-E. Recent outcomes of this effort are the Framework Guidelines and Network Codes that will lead to implementing an EU-wide target model for the wholesale market, with an implementation deadline of 2014. Harmonization will be accomplished for EU-wide congestion management with a day-ahead market, which will encompass the entire EU with harmonized bidding and pricing rules. Further harmonization is also being sought for more complex short term issues, such as the coordination of the balancing markets of the different MSs, a very demanding task that requires a great deal of engineering and organization skills.

Efforts are also being made at EU-wide level regarding the fourth dimension of security of supply: the *strategic energy policy*. Within the Third Package of reforms of the energy markets, commitments have been made and targets have been established regarding reduction of CO2 emissions, level of penetration of renewable energy sources, improvements in energy efficiency and promotion of innovation. An ambitious 2050 Energy Roadmap has been announced. These measures and targets will dramatically shape electricity markets in Europe for the next decades.

While all this is taking place, several countries in Europe have implemented, or are in the process to implement, a diversity of regulatory instruments that try to address their concerns regarding the *adequacy* and *firmness* dimensions. Figure 1 shows the situation regarding the actual or expected implementation of capacity support mechanisms in the Member States of the EU[3]. So far the European institutions have not adopted any measure or issued any guideline regarding whether it is convenient or not to harmonize these efforts. However, given the reasonable concerns about future generation investments in European countries –because of the financial difficulties associated to the economic crisis, the uncertainty regarding the regulatory-driven level of penetration of clean technologies and the future regime of functioning and prices in an environment of strong presence of renewable generation–, the issue of the convenience of some

[3] Still not all existing approaches seem to be represented in the Figure. At least the "safety net" scheme in The Netherlands is missing.

harmonization measures of the adequacy and firmness in the European electricity markets cannot be ignored any longer[4].

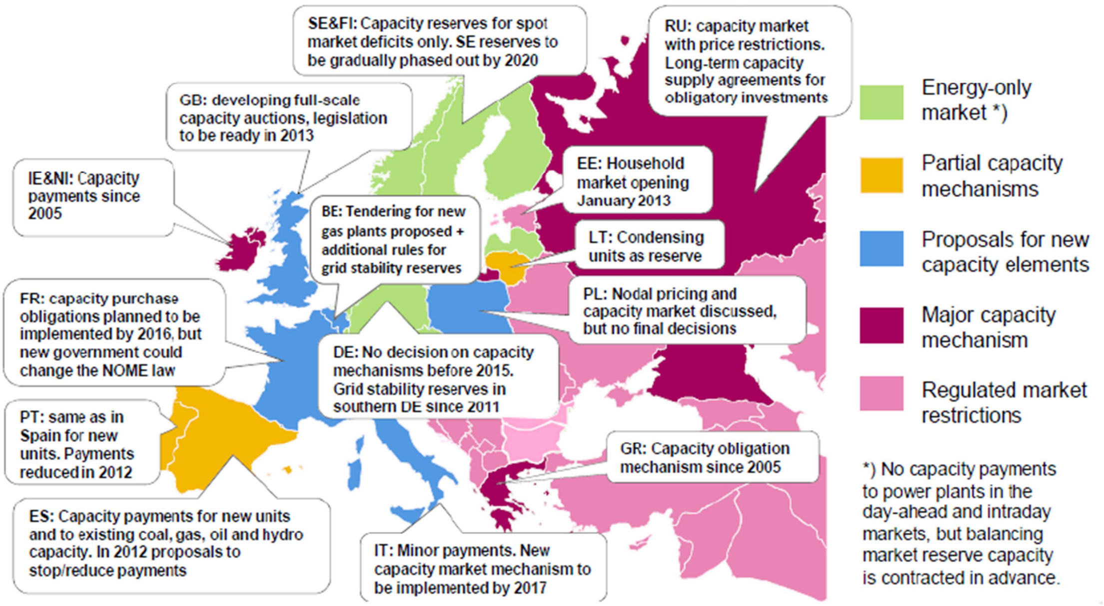


Figure 1: Capacity mechanisms in the EU Member States. Source: Eurelectric, EU Stockholder Forum, March 8, 2013.

It is also possible that some European countries, because of the concern that the profitability of generators might have been reduced because of the demand reduction caused by the global economic crisis, might decide to introduce new or to enhance existing capacity support mechanisms “for the wrong reason”. This might be subject to State aid scrutiny by the European Commission.

3. 3. The issues to be examined

These are the major questions to be examined in this paper:

[4] Several recent documents by the key EU institutions in power sector regulation reflect this concern: the Consultation Paper on generation adequacy, capacity mechanisms and the Internal Market in Electricity by the European Commission (November 2012), the EU-wide generation adequacy assessments by ENTSO-E, and the Opinion of ACER on Capacity markets (February 2013).

1. Is there a market failure that justifies the utilization of capacity support regulatory mechanisms? What is the economic rationale for these support mechanisms?

2. Does flexibility need support with a specific regulatory instrument? Should capacity mechanisms be adapted to achieve also flexibility, besides adequacy and firmness?

Assuming now that some sort of regulatory instrument is justified, and in the context of the EU Internal Electricity market:

3. Is the diversity of capacity instruments at Member State level something to be concerned about, because it may result in inefficiency or loss of security of supply in the functioning of the IEM?

4. What is the scope of the impacts of these potential inefficiencies: only at investment level or could they also concern the efficiency of functioning of the short-term wholesale market?

5. If potential inefficiencies do exist, is some action from ACER or the EU Commission necessary to make sure that they do not materialize? Are there any missing pieces in the regulatory and legal framework?

3. 4. Is there a market failure?[5]

Can energy-only electricity markets be successful by themselves in attracting enough generation investment to provide an acceptable level of adequacy and to manage it for a satisfactory level of firmness in operation? How would the consumers and generators hedge against the uncertainty and volatility in market prices?

[5] An extensive discussion of this market failure and the regulatory mechanisms to fix it can be found in Chapter 12 of the book "Power system regulation", edited by Ignacio J. Pérez-Arriaga, Springer Verlag, May 2013.

Several power systems have tried the orthodox approach: an energy-only electricity market. It seems that only the Australian National Electricity Market (NEM) has persevered[6] and succeeded[7]. The NEM has a very high price cap (A$12,500/MWh or US$9,625/MWh), it has volatile and very spiky prices (140 half hour periods with above A$480/MWh prices and 16 half hour periods with above A$8,500/MWh prices during 2010) and generators and suppliers voluntarily use hedging instruments.

Most hedging instruments in the NEM are “swaps” and “caps”:

- *Swaps* are contracts for differences with a fixed strike price per MWh for a defined volume of energy at a given time and at a defined node, and they are meant to buy and sell most of the energy.

- *Caps* are call option contracts that place a cap on the electricity market price for the contract duration at a defined node. Caps are typically sold by generators, which self-hedge by owning peaking generation and operating it when prices are high. The buyer (typically a supply business) pays a fixed price per MW for the contract (close to the investment cost of a peaking plant). The contract provides a price cap for the agreed MW capacity for all price periods in the year. The seller compensates the buyer if the pool price is greater than the strike price in the contract. The typical strike price is A$300/MWh and corresponds to the variable operating costs of the open cycle gas turbines typically used to support these contracts.

[6] This market has a “contract for reserves” mechanism that can be used by the System Operator to keep a reliability standard of 0.002% of non-served energy, but it has been cancelled in June 2013. Most of this information from the NEM comes from Jamie Carstairs at Linnfall Consulting.

[7] All this being true, it cannot be forgotten that in the NEM around 60 % of the generating capacity is government-owned or controlled.

Why most electricity markets have failed in adopting the energy-only approach or have decided to use capacity support instruments directly? This market failure is typically the combination of some or all of the following factors:

- Regulators set low price caps (or intervene capping prices whenever high prices start to happen) to protect consumers (and themselves from critics) from high market prices, and they also want a good (even extra) reliability level at the same time, what is not possible.
- System operators frequently find ways of avoiding price spikes (applying all sorts of emergency measures), thus frustrating the reasonable income expectations of peaking (and also all other) generators during scarcity periods.
- Consumers are reckless (do not hedge) since they think the regulator will protect them from high prices. Moreover, consumers typically do not sign contracts long enough to facilitate entry of new generation investment.
- As a consequence of the factors above, the expected income by potential new generator entrants is so uncertain (mostly because of regulatory uncertainty) that triggers risk aversion, therefore requiring some sort of supporting regulatory instrument.

It is also important to understand that the "missing money" that is so frequently cited as the main cause of this market failure does not exist in a market equilibrium situation. Missing money, or windfall profits, will only happen transitorily because of non-anticipated changes in the market conditions. Markets adapt (with time) to imperfections and interventions in their designs, resulting in (possibly) less efficient outcomes, but with full cost recovery (obviously including a rate of return on the invested capital). The response of generation investors in an electricity market with price caps is to reduce investment until higher market prices (and the associated reduced reliability) compensate for the loss of investment. “Missing money” may happen transitorily, as it is always the case when a market has to adapt to any unexpected substantial change in regulation, production costs, demand or whatever. A case of particular interest is a change in a non-anticipated ambitious renewables target; since solar PV and wind generation can be deployed fast, they may cause a transitory income deficit for conventional plants (windfall profits may also occur in other instances). Other measures to reduce or eliminate the price caps (emergency measures by the SO: voltage reduction, interruptible loads, emergency imports, generation above rated capacities) have similar impacts on investment.

Capacity mechanisms in a context of massive penetration of intermittent renewables: Does flexibility need support with a specific regulatory instrument?

Today, the design of long-term security of supply mechanisms needs to properly account for the effect of the increasing penetration of intermittent renewable generation. This generation is less predictable and more variable than conventional power plants, and this fact changes to a large extent the operation and decision-making processes. A well-designed security of supply mechanism has to properly deal with the fact that a large amount of production will not be guaranteed until near the time of delivery, and that more flexible generation resources will be needed to deal with larger short-term variations in production. The question is whether some additional incentive should be provided to this “flexibility” feature.

In this respect, it is noteworthy that while some mechanisms simply add an additional remuneration for capacity (former ICAP in PJM), other superior designs also amplify short-term market signals (such as those mechanisms based on the reliability options). The aforementioned penalty for not producing when the price reaches the strike price could be seen as a way to amplify the impact of not producing during those periods. Since short-term signals implicitly account for all system requirements (not only capacity but also flexibility and others), it still has to be analyzed and proven that a properly designed mechanism would need to include extra incentives to achieve "flexibility"[8].

If the previous analysis leads to the conclusion that an additional flexibility incentive needs to be provided, the mechanism would unavoidably be technology-oriented. Note that regulatory interventions (operating reserves, firmness requirements, capacity instruments or energy policy measures) are never completely neutral technologically & they can be used to achieve dual purposes. A clear example is the generation capacity auctions in Brazil, whose characteristics determine in each case the technology that is expected to win.

Finally, another issue that seems to be raising some controversy is to what extent renewable generation can participate in long-term capacity markets. In this respect, a number of relevant questions to be answered arise: should we allow wind and solar PV to participate in capacity mechanisms? Only when they are not supported by any mechanism? In the case they are allowed to participate, how the long-term capacity contribution of renewable generation can be determined?

3. 5. Regulatory instruments within a single system: Is there a dominant design?

Capacity support mechanisms have evolved much during the last two decades, and, although no universal solution has been forthcoming, the international experience has helped narrow the range of possible measures that should be considered by regulators. Broadly speaking, there are three major strategies from which to choose.

[8] Determining the short-term signal to be used as a reference market is a complex and quite interesting discussion that falls out of the scope of the present paper (is it the day-ahead?, is it the balancing?, is it in between both?, what if there is not and organized market for the "correct" time scale?).

3.5.1. Do nothing, i.e., an energy-only market

This approach has been discussed already, as well as the reasons why multiple real-life factors may result in market failure and non-satisfactory levels of generation adequacy and firmness.

In the alternative option, the regulator acts on behalf of demand and defines a commodity, the "reliability product", meant to improve adequacy and firmness, plus a procedure to determine the providers of the commodity and the associated remuneration. There are two main schemes when implementing this option.

3.5.2. Price-based instruments

In this case a monetary sum that is determined by the regulator, and often known as the *"capacity payment",* over and above the income derived from the energy (spot) market, is devoted to remunerate the reliability product, which is some sort of "firm capacity" defined by the regulator. Versions of the capacity payment method have been used since the very first market designs in Latin America and have been extended elsewhere, but the major shortcomings of the method have never been overcome: no guarantee that the adequacy objective will be achieved; too weak incentives to achieve firmness, because of the absence of a well-defined deliverable reliability product; and total discretion by the regulator when determining the firm capacity of each plant and the remuneration, which is a source of regulatory uncertainty.

3.5.3. Quantity-based instruments

Now the regulator requires the demand to purchase a specific quantity of the reliability product, or buys it itself on behalf of the consumers, and relies on some market procedure to set the price. Depending on the market design, the reliability product may adopt a variety of formats and may be traded in different forms. Various quantity-based schemes have been implemented.

Long-term auctions for reliability options contracts[9]

Some entity (e.g. the System Operator) is designated by the regulator to purchase through an auction, on behalf of the entire demand, a predefined volume of a well-specified reliability product –a *"reliability option"*–, which is a combination of a *financial call option* (with the same format as the "caps" that are used in the Australian NEM: the buyer of the option has the right, but not the obligation, to buy electricity at a predetermined strike price, instead of the actual spot price, up to the contracted amount in MW; meanwhile the seller receives in exchange a premium) and *a physical delivery obligation* (the seller has to pay a penalty if the spot price reaches the strike price value and the seller is not generating the contracted amount of MW capacity).

The regulator determines the total amount of reliability options to be auctioned, the strike price, the penalty, the lag period (number of years before the commitment is activated, to give the successful bidders time to build their plants after having hedged their risk exposure) and the duration of the commitment. It is up to the sellers of the options to determine the amount of capacity and the price to be bid in the auction[10]. Both generators (supply) and demand (reduction) may participate selling options in this market.

This mechanism guarantees a predetermined adequacy level and creates a strong incentive for the sellers of the options to deliver generation or demand reduction when the system is under stress. It also protects the consumers against high spot market

[9] A detailed description can be found in C. Vazquez et al. "A market approach to long-term security of supply", IEEE Transactions on power systems, vol.17, no. 2, pp. 349-357, May 2002. This method was first designed for the Colombian market in the late nineties by a team from the Institute of Research in Technology (IIT, at Comillas University) and versions of it have been adopted in several Latin American and US markets, Italy and the UK market reform.

[10] And the regulator may either cap the maximum amount each generator can bid or alternatively fully rely on the market (in the hope that the penalization will in the end give generators a strong incentive to bid their "firm" supply).

prices[11]. And it has the cost of the premium, as determined by the auction. This mechanism may be activated only when the existing energy market prices are not sufficient to attract enough new investment.

Capacity markets[12]

This mechanism imposes consumers, or any suppliers serving them, the obligation to purchase in the market a firm capacity equal to their demand plus a certain reserve margin. The regulator determines the firm capacity of each generating unit, so it can bring its bids to the capacity market.

This method also guarantees an adequacy level, but the firm capacities have to be determined by the regulator, consumers are not hedged against high market prices, firmness is not sufficiently incentivized and, most important, as actually implemented with short lag periods and short durations of commitments, the price of capacity is expected to be (and it has actually been, in the implementation in some US markets, like PJM) very volatile.

Long-term auctions

The Directives of the Internal Electricity Market and of Security of Supply allow Member States to run auctions for needed new generation capacity that has not been obtained otherwise, and to assign long-term contracts to the winning bidders.

An auction scheme is systematically and successfully used in Brazil, where it helps financing new investment projects via long-term contracts, which for some technologies adopt the format of the reliability options. In the EU it seems that Member States have

[11] And therefore looses any demand response to prices above the value of the auction strike price.

[12] The term "capacity markets" is strictly used here to refer to the method that was implemented in several Independent System Operators in the East of the USA in the early 2000s and not, as it is sometimes employed, to be equivalent to the much broader category of "capacity mechanisms".

preferred to adopt a variety of procedures to support generation capacity investments (see Figure 1).

Strategic reserves

The method consists of separating off certain amount of generating capacity (peaking units, typically) that does not participate in the energy market unless the regulator or the System Operator find it necessary, according to some prescribed criterion. If this criterion, as well as the one used to decide the purchase of reserves, is well designed, this mechanism can give acceptable results.

Note that the strategic reserves capacity cannot be used until the trigger criterion is activated. This is a major difference with the reliability options approach and it is a source of inefficiency.

General design criteria for the implementation of capacity mechanisms[13]

The aim of any capacity mechanism is to provide an added incentive for market agents to raise their contribution to overall system reliability, and more precisely to system firmness and adequacy. The definition of the reliability product that is subsequently priced to establish the incentive lies at the core of the design.

The definition of the reliability product must include the following components (the description is mostly inspired by the "long-term reliability options auction" method): a rule to determine what constitutes a critical period (scarce supply to meet demand); a criterion to evaluate the actual contribution of each committed entity (either generating unit or responsive demand) during this period; the duration of the commitment; and, finally, safeguards to prevent gaming, free riding and credit risks.

[13] A detailed discussion can be found in C. Batlle and I.J. Pérez-Arriaga, "Design criteria for implementing a capacity mechanism in deregulated electricity markets", Utilities Policy 16 (2008) 184-193.

3. 6. Regulatory instruments within a regional market like the IEM: Is there a need for harmonization?

On November 2012, in the Communication "Making the internal energy market work", the European Commission discussed which the current situation is in Europe with respect to the implementation of long-term security of supply mechanisms:

> *"some member states have introduced or plan to introduce separate payments for the market availability of generation capacity, as they are concerned that the 'energy only' market will not deliver sufficient investment in generation"*

At the same time, the European Commission warned about the major risks stemming from this current situation:

> *"if capacity mechanisms are not well designed and/or are introduced prematurely or without proper coordination at EU level, they risk being counterproductive" and that "poorly designed capacity mechanisms will tend to distort investment signals".*

These concerns are addressed in the following.

3.6.1. The priority is a joint approach to reliability

The existence of a "regional" market should necessarily imply that there is some sort of joint approach to reliability (and only as a secondary concern that the proliferation of local capacity mechanisms may distort the energy market). A minimum requirement in a regional market should be that all agents in the regional market must be allowed to participate in whatever capacity mechanism is established by any local authority. In other words, that a commitment of a generator located in system A to contribute to the capacity mechanism in system B, cannot be cancelled by the regulator in A because the capacity committed to B is also needed in system A.

A true EU-wide approach to adequacy and firmness requires reliance of any country A in any generation capacity located in another country B that has been committed to provide guarantee of supply in A. This reliance is defeated if country B may call back the contract with country A of generators in their territory in case there is a supply crisis in B. Obviously the problem with firmness only arises when both countries have a supply crisis, since only then the contracted generation in B cannot be replaced by anything else. What should prevail in this case: the contract or the potential request of the regulator in B to suspend any exports while demand in B cannot be totally met? It is clear that a true security of supply for electricity at EU level will only happen when import and export physical contracts have priority over any domestic demand without such contracts. This seems to be the direct interpretation of article 4.3 in the Security of Supply Directive: “In taking the measures referred to in Article 24 of Directive 2003/54/EC (*it refers to measures to be adopted in emergency situations*) and in Article 6 of Regulation (EC) No 1228/2003, Member States shall not discriminate between cross-border contracts and national contracts”. Unfortunately, most electricity laws of the Member States have explicit clauses maintaining that exports to other countries will be interrupted in case of a domestic emergency of supply. And these provisions have been applied whenever there has been the occasion for it.

3.6.2. The need for harmonization

It is to be expected (but it is still a hypothesis) that a joint approach to reliability and the rule that has been exposed in the previous paragraph (which amounts to Article 4.3 of the Security of Supply Directive) will significantly reduce any possible distortion of the local capacity mechanisms in the EU-wide electricity energy market and will (subtly) reduce the proliferation of disparate capacity mechanisms & converge towards the dominant (preferable) ones.

Implementation of the EU target model will require some countries to overhaul the current design of their wholesale electricity markets. It is well known that the design of an electricity market comprises both the short-term and the long-term issues in an inseparable way. It does not seem reasonable to ask some countries to adapt the rules of their short-term markets to a common target model without giving them any indication regarding whether their existing mechanisms for adequacy and firmness will have to be also harmonized.

3. 7. Discussion

Questions 3, 4 and 5 (copied below) that were asked before are still unanswered.

3. Is the diversity of capacity instruments at MS level something to be concerned about, because it may result in inefficiency or loss of security of supply in the functioning of the IEM?
4. What is the scope of the impacts of these potential inefficiencies: only at investment level or could they also concern the efficiency of functioning of the short-term wholesale market?
5. If potential inefficiencies do exist, is some action from ACER or the EU Commission necessary to make sure that they do not materialize?

These are complex questions and no definitive answer will be given here. Some hints will be provided about the options available to the European institutions when trying to harmonize regulatory instruments for adequacy and firmness.

Regarding the third question, one may think, in a first approximation, that the size of the large and medium size European countries and the relative uniformity in the generation mix –or at least the technologies setting the marginal market price– in most countries do not justify the need for an EU-wide capacity mechanism. Under these conditions, extending the size of the national markets to a European dimension would have a small beneficial impact of reducing the safe adequacy margins of installed generation capacity over the system peak demand.

However, this uniformity is quickly disappearing because of the strong levels of penetration of wind and solar generation in some countries. Major developments of renewable generation, such as the North Sea off-shore wind or Desertec in Northern Africa, may profoundly alter the generation patterns in some European countries and create local surpluses and deficits of installed generation capacity that could be used by other countries. In the medium and long term, the variability of wind and solar may create local temporary deficits of electricity production in some countries that could only be met by very active demand response and recourse to generation in other countries. Well-established rules of generation support at EU-level would be very useful in this context.

Several issues have to be considered when trying to answer the forth question. Well-designed capacity instruments (i.e. regulatory measures meant to address firmness and adequacy issues) should not interfere with the functioning of short-term markets. However, disparity in the adoption of capacity instruments in different countries will result in loss of efficiency in the deployment of installed capacity. The different types of capacity support mechanisms have been previously described, and all of them are present in EU Member States, in one version or another. Even if a common kind of approach is adopted, if different countries choose different versions (i.e. different adequacy and firmness levels, definitions of emergency conditions, economic terms, etc.) incompatibilities will appear that will prevent the use of the existing and future generation capacity to meet some ideal global EU requirements in the most efficient way.

To facilitate the analysis of the fifth question, several levels of possible harmonization requirements are offered next, as an example, in the format of market design principles, starting from the lighter ones, in increasing order of the level of EU intervention:

a. Mandate, or just encourage, that any capacity mechanism that a Member State decides to create is open to agents of other Member States. This principle seems to be consistent with the spirit of the abovementioned article 4.3 of the SoS EU Directive.

b. Make sure that the regulations and the coordination between Member States do not allow that any given adequacy or firmness value of a power plant is sold twice.

c. Member States with capacity mechanisms should coordinate their implementation.

d. Some level of harmonization of the adopted capacity mechanisms would be desirable, in order to reduce inefficiencies.

A more ambitious design of a EU-wide capacity mechanism would have to go beyond rule (D) to establish a single harmonized instrument for the entire EU electricity market. Note that principle (A) could be understood, particularly for countries at the European periphery, as just an extension of a multiplicity of individual national capacity instruments beyond their respective MSs borders and, therefore, not the same thing as the –conceptually, at least– more efficient single EU-wide capacity mechanism.

However, despite the potential inefficiency that the diversity of schemes may cause, this opening to foreign participation has to be considered as a welcome contribution to take advantage of opportunities to reduce the need for additional investments in generation capacity at European level. As indicated before, it is realistic to expect, during the evolution in time of the Internal Electricity Market, that cases will take place of local overcapacity, simultaneous closure of plants (such as the nuclear shutdown in Germany) or geographically asymmetrical developments of renewable technologies within the EU.

EU-wide capacity mechanisms will be helpful for the countries to mitigate the consequences of these imbalances.

3. 8. Policy recommendations

The following policy recommendations are directly related to the questions being addressed in this policy paper:

- While the prevalent regulatory, political and social conditions in the EU Member States do not make plausible the existence of a true energy-only market, it has to be accepted that support mechanisms for adequacy and firmness will have to exist. Being pragmatic, this has to be considered a permanent, rather than a transitory, situation.
- Properly designed capacity mechanisms will minimally interfere with the short-term electricity market as in the EU target model. It has to be realized the complexity of the supply of electricity under market conditions (and even more in the presence of a strong penetration of renewable generation), which actually results in a multiplicity of parallel markets: markets for ancillary services, the short-term spot market for energy (as in hourly day-ahead markets), and the capacity markets seeking to obtain suitable values of adequacy and firmness with market mechanisms.
- The generation mix of future power systems will have to be increasingly flexible to accommodate the anticipated growing volume of intermittent generation. In principle, this does not necessarily mean that support regulatory instruments will have to be developed just for this purpose. It may well happen that properly designed short-term markets and capacity mechanisms will provide a generation mix with a satisfactory flexibility level.
- The overriding concern for the EU IEM regarding the proliferation of capacity support mechanisms should not be the potential losses of efficiency because of

the diversity of approaches in the different Member States. The major reason for the loss of efficiency is that a generator in a country A cannot participate providing firm capacity to a neighboring country B, because the legislation in country A (in flagrant violation of article 4.3 of the Security of Supply Directive) does not guarantee that the contract of provision of firm capacity of the generator to country B will be honoured if country A also needs that generator[14].

[14] One might argue that situations of generation scarcity are rare in the EU today. The answer is: if contracts of firm capacity are not honored, in a future scenario with a strong presence of wind and solar generation in Europe, every country will have to fully back up its intermittent generation with its own conventional generation, which is obviously inefficient.

4. Europe's Generation Mix: The Carbon Challenge

by **Professor Richard Green**

4. 1. Summary

The electricity industry is a tightly interconnected machine. Because demands fluctuate and electricity cannot easily be stored, power stations play different roles in this system: some run for long periods, others only at peak times. Stations with low fixed costs are most suitable for peaking use, while low variable costs are important for base load stations.

The three low-carbon options for electricity supply are nuclear power (not acceptable in some European countries), fitting carbon capture and sequestration to some fossil-fuelled stations (not yet proven at full scale, and inevitably more expensive (at the station) than unabated generation) and renewable power. Many renewables, particularly solar and wind power, are intermittent, and will lead to greater fluctuations in the load on the rest of the power system. In turn, more stations will run for relatively short periods, creating a bigger market for peaking plant, and a relatively smaller base load market, than in the past.

Increasing the level of demand-side response and international trade are likely to help in the task of absorbing renewable power. If cost-effective storage technologies can be developed, they will also play a role – but even so, the costs of expanding transmission and storage will be too high for either to be a panacea. Appropriate market and regulatory rules will be needed to encourage all of these, however, and the EU may need to go further than its current "target model", perhaps setting up transnational system operators that are also responsible (along US lines) for energy trading to send accurate price signals to generators and consumers. At the same time, prices that accurately signal widely fluctuating costs create risks, and a high cost of capital would

greatly increase the cost of decarbonising Europe’s electricity. Support schemes such as feed-in-tariffs, which minimise risks and hence the cost of capital, are most likely to make decarbonisation affordable.

Even so, the price of power is very likely to rise, and this will have consequences for households and companies across Europe. Support for energy efficiency may mitigate the rises for households, and should be targeted on those with the highest fuel bills relative to their incomes. Companies in energy-intensive sectors need special consideration if they are not to suffer a sudden loss in competitiveness. That could lead to a contraction that would be much faster than replacement jobs can be created in the sectors that have become relatively more competitive. A border tax adjustment may be the most effective tool for this from the economic point of view. Politically, it may not be easy to implement.

4. 2. Generation in the Electricity System

Electric power systems have been described as the largest machines in the world. Within an interconnected Alternating Current (AC) system, such as the grid in the UCTE countries of Central and Western Europe, every power station and every device that uses electricity must operate exactly in phase. Generation must match demand at every moment, and the flows on every part of the transmission and distribution networks must stay within their limits. If any of these constraints are breached, the affected part of the system is likely to shut down to protect itself. This will normally create further imbalances, and cascading failures can cause millions of people to lose electricity supply in a matter of minutes – as electricity customers in Germany and its neighbours (2006), Italy (2003), Sweden and Denmark (2003) and many other EU countries know only too well.

This means that the system must be carefully controlled to ensure that the operating constraints are not breached. Since the demand for electricity is dominated by consumers – firms and households – who are not able, and may not even wish, to respond to the needs of the system controllers, generators bear most of the burden of keeping the system stable. Electricity must be generated (or withdrawn from storage) at the moment it is consumed, and at present, the only economical way of storing large amounts of power is in hydro stations. The demand for power varies predictably over the day and over the year, and also varies unpredictably in response to the weather and the economic cycle.

These factors mean that some power stations will be able to run at full capacity for all the hours in which they are technically available, but that many will not. The highest levels of demand occur for only a few hours in each year. Almost every power station in the country may be required at those times, but in the majority of hours with lower demand, some of those stations will not be needed.

The costs of operating an existing set of power stations will be minimised when the stations with the lowest variable costs run for the greatest number of hours, and those with high variable costs are run infrequently to meet the peaks in demand. When technical limitations (such as limits in the flexibility with which stations can be turned on and off, or constraints on the transmission system) mean that the apparently cheapest station cannot be used, a more expensive station must be substituted. The broad principle then can be amended to making the greatest use of the stations with the lowest variable costs *among those capable of meeting the pattern of demand.*

Investment decisions depend on capital costs as well as operating costs. If a potential station has low operating costs, it could be a good investment, even if its capital costs are high, as long as it will be able to run for long periods and take advantage of those low costs. If its operating costs are high, in contrast, it should not normally be run for long periods, and would only be a good investment if its capital costs were low.

Traditionally, utilities made investment decisions based on least-cost planning methodologies, attempting to meet a predicted level of demand, together with a safety margin to cover plant failures and unusually high demands. In many countries, newly added stations would have the most modern technology and the lowest variable costs, therefore running on base load to meet demand throughout the year. Older stations would have less efficient technology and hence higher costs, and would naturally tend to generate less as they aged. Much of the higher demand levels would therefore be met by this reserve of older stations, which were available relatively cheaply, since their capital costs had already been sunk. Even so, it would sometimes be worthwhile adding new stations specifically as peaking capacity. If demand had grown faster than anticipated, it might not be possible to add new base load capacity (which typically took longer to build) in time. Alternatively, the shape of the load-duration curve might be changing, with peak demands growing faster than the base load, creating a need for relatively more capacity that would only be running for short periods. If the growth in peak demands was low, it would sometimes be worth retiring the oldest stations (or those with the highest variable costs) before the end of their technical lifetimes. If the newest stations had particularly low costs, it could also be worth investing in them, replacing older plant, even if there was little demand growth.

During the 1990s, the EU and its Member States adopted a policy of electricity market liberalisation. Integrated utility planning was replaced by market mechanisms, in which investors would be expected to build new power stations if they saw a profitable opportunity to add capacity. Older stations would close if they were no longer profitable, and their owners saw too few prospects of any improvement. Profitability would be evaluated at the expected wholesale market prices – either the prices in the short-term spot markets, or those obtainable through longer-term contracts. If the industry is short of capacity, prices will be high and investment should be very profitable, and plant closures unprofitable, creating incentives for the responses that the system needs. A surplus, in contrast, leads to low prices and creates incentives to delay investment and even to close existing plants.

In principle, the market mechanism should provide similar signals to utility planning, in terms of the types of power station required to profitably meet future demand, together with stronger incentives to build and operate those stations efficiently. In practice, investment has often followed cycles of boom and bust, if too many companies invest at one time, and it then becomes clear that the industry has over-capacity which must be eliminated by demand growth or plant closures before further investment is desirable. This was particularly apparent in the north-eastern United States around the turn of the Millennium, but the UK also saw over-capacity and low prices in the years around 2002. If the larger companies have market power, they may be reluctant to create too much spare capacity, but if they succeed in keeping prices high, this may encourage entrants. Again, English generators closed plant in the 1990s to stop capacity margins from getting too high, and the apparently stable prices helped trigger the subsequent excessive entry.

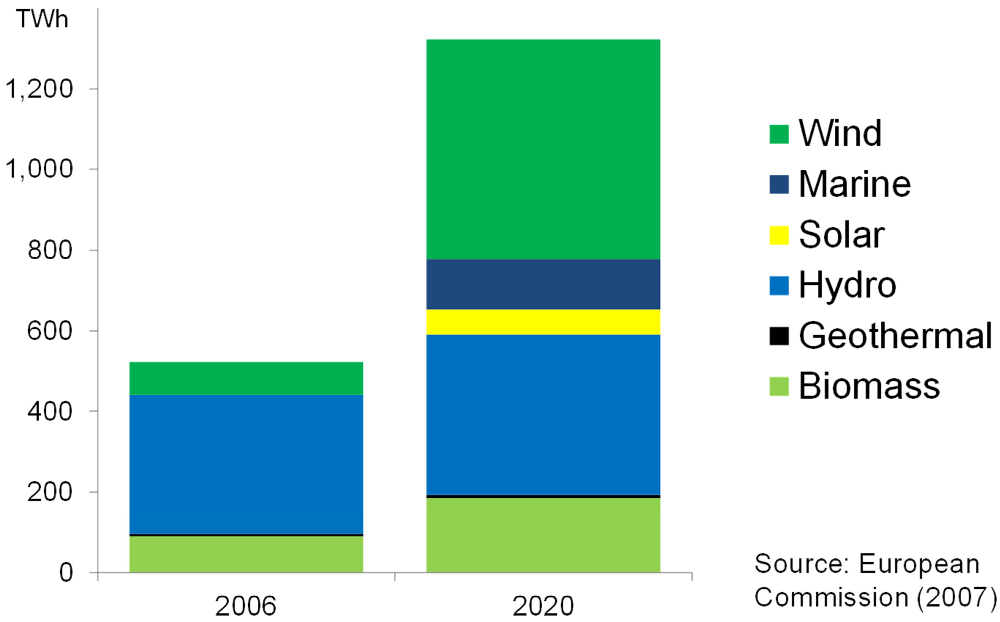
4. 3. Options for Decarbonising Electricity

There are three ways to decarbonise electricity supplies: nuclear power, renewable energy, and the addition of Carbon Capture and Sequestration (storage) (CCS) to power stations burning fossil fuels. In addition, the total emissions from the electricity sector will fall, even if emissions per MWh remain high, if the demand for electricity is reduced. Policies to promote energy efficiency do this in a desirable manner; macroeconomic failure is a deeply undesirable way of reducing electricity emissions.

Nuclear power is no longer politically acceptable to some Member States, although other countries are still investing, or hoping to invest, in new nuclear power stations. Nuclear power has very high fixed costs, and low variable costs, making it suitable for base load operation, but an expensive way to meet loads that only last for part of the year. This is in part because the high fixed costs of the station must be spread over a smaller volume of output; many nuclear stations are also relatively inflexible in operation.

Renewable power comes from many different sources. When the EU agreed its Climate and Energy Package, with a 20% reduction in carbon dioxide emissions and a 20% share of renewable sources in final energy demand, hydro stations provided the great majority of its renewable electricity, as shown in Figure 1. Hydro-electric stations have the great advantage of being dispatchable – that is, they can be turned on and off as required so that the overall profile of generation matches demand. Large stations are environmentally intrusive, however, requiring the construction of dams, and there is little scope for more large-scale hydro in Europe. The European Commission's (2007) analysis of the cheapest way of meeting the renewables target does include an increase in hydro generation, including smaller-scale, less intrusive, run of river schemes.

Figure 1: Renewable Electricity Generation, EU-27
(predictions from the Green-X model)

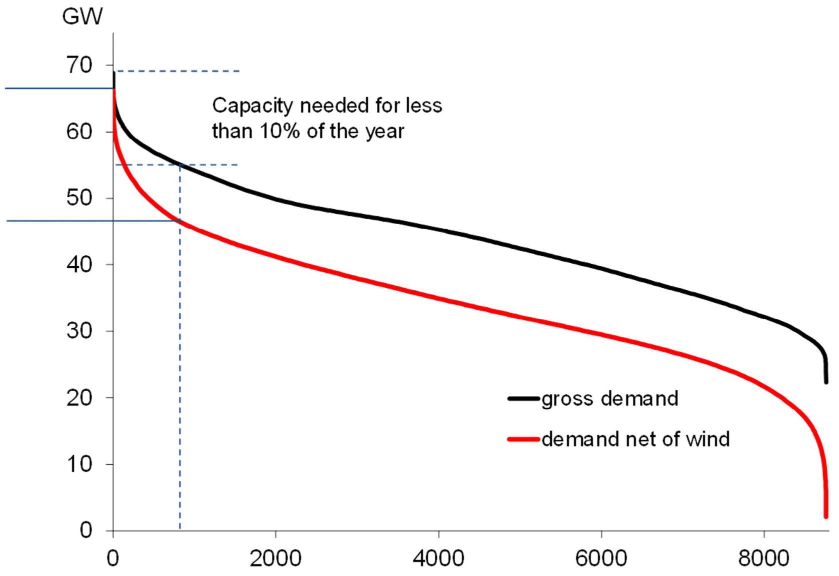


The second largest source of the EU's renewable electricity in 2006 was biomass, burning fuels such as wood, other crops grown for energy, some forms of domestic waste and gas from landfill sites and sewage works. Most forms of biomass are also dispatchable. On the other hand, biomass may displace food production and emissions during its production can be high; there are also risks to biodiversity, particularly if it sourced from tropical countries. The amount of biomass generation was expected to double, but its share of total renewable power would fall, since the latter is required to increase by 150%.

More than half of that increase was expected to come from wind power, rising from 16% of the EU's renewable power (itself the result of a massive increase over the previous decade) to just over 40%. Wind power is not fully dispatchable, in that it is only available when the wind is blowing. Modern wind turbines can be easily turned down (and up again) if the system is unable to accommodate all of the power that they could produce on a windy day, but if the weather is calm, the turbines are idle. Forecasts of the output of wind turbines have become increasingly accurate over a few hours, or even days, ahead, allowing other stations to be scheduled when there will be too little wind.

It should be noted that in a number of EU countries, the winter weather that produces the highest demands for electricity is associated with calm conditions and hence very little wind output. This means that the presence of substantial amounts of wind capacity may have little impact on the net demand for other generation at the times of peak demand. Wind stations can replace large amounts of fossil fuel, but they cannot replace generation capacity. As the amount of wind generation rises, the load factor of other stations will fall. Figure 2 shows two load-duration curves for Great Britain, each of which charts the number of hours for which demand will be at or above a given level. The upper line shows the total demand for electricity, and the lower line shows the demand that would remain for thermal power stations after the output from 30 GW of wind power is absorbed. The top left corner of each line shows that the capacity needed to meet the highest demands (ignoring reserve requirements) would only fall slightly. The vertical line marks the 10% of hours with the highest demands, and the distance between the two dotted horizontal lines shows how much capacity would be needed for no more than 10% of the time. The two unbroken lines show that much more capacity would be needed for similarly short periods after the expansion of wind power. Several countries are introducing special mechanisms to finance stations that are not needed very often, but are important for security of supply at those times.

Figure 2: Demands with and without wind
Great Britain in c.2020



Source: Green (2010)

Two other classes of renewable generation are expected to rise from almost nothing to make significant contributions to the 2020 targets; marine energy and solar power. Marine energy – wave power, turbines moved by tidal currents, and barrages to exploit the water moving in and out of estuaries – varies in terms of its predictability and whether it can be dispatched. The strength of the waves near the coast depends on the previous strength of the wind out at sea, which can only be predicted in the short term, whereas tides can be predicted into the far future. Tidal barrages can be designed with several lagoons in such a way that there will almost always be a way of releasing water from a lagoon with a higher water level into one which is emptier, thus generating power on demand; however this would increase the cost or reduce the capacity of a scheme.

Finally, solar power depends on the interaction of the predictable strength of the sun and unpredictable atmospheric conditions. Its output is obviously greatest in summer, in contrast to the wind, which is stronger in winter in many EU countries. This is useful for countries where demand peaks in the summer afternoons, driven by air conditioning, but is less useful for those with peaks in the winter evenings. Concentrating solar power technologies, where the sun heats a fluid which is then used to generate electricity, have the advantage that the heat can be stored for a few hours (at a cost), making them partly dispatchable.

The third way to decarbonise electricity generation is through CCS applied to fossil fuel power stations. Adding the carbon capture equipment to a power station is likely to make it less flexible in operation, although it should still remain more flexible than nuclear power. Nuclear and renewable power offer the possibility of electricity that would be cheaper than from fossil fuels, if the price of the latter rose significantly or if there were rapid reductions in the costs of the newer technologies.[15] Adding CCS to a fossil station must inevitably increase its cost, compared to that of a station with no constraints on its carbon emissions – more equipment is needed and more fuel will be burned. The business case for CCS must rest on those additional costs being lower than the payments[16] needed for the carbon emissions that it saves. The case for society is based on the costs of climate change – uncertain and distant though they may be – being greater than the costs of mitigating it, as shown by the Stern Review (2007).

It is worth adding that even a very low-carbon electricity system may contain some unabated fossil fuel stations – that is, those without CCS. Fitting CCS to a station that is

[15] The cost of solar PV panels has been declining rapidly, but from a high base. The costs of the two nuclear stations currently being built in Europe have risen far above initial estimates; it remains to be seen whether these are first-of-a-kind problems or intrinsic to the problem of producing nuclear power to the latest safety standards.

[16] Generators might have to pay for carbon under an emission trading scheme, as currently operates in the EU, or through a carbon tax.

expected to operate for only a few hours per year (either because it is explicitly built as a peaking station or because it is an old and relatively inefficient plant) would imply a very high cost per tonne of carbon saved. Because the stations will not run very often, their overall emissions will be low. Closing these stations would require that they were (expensively) replaced with alternatives that would, in turn, not produce much power. This would not be a sensible use of scarce resources.[17]

4. 4. A Low-Carbon Electricity Mix for Europe

The optimal low-carbon power system in a given country will depend on its endowment of natural resources. Solar power will be cheaper in the south of Europe than in cloudy northern countries, while areas near the Atlantic coast typically have higher wind speeds, and hence cheaper wind generation, than elsewhere. The amount of biomass available for power generation also varies between countries.

This means that while Figure 1 suggests a broad portfolio of sources will be used across the EU-27, particular regions may see a concentration of one type of generation. This will be most important for the intermittent renewables, solar and wind power. If a large amount of intermittent generation is added to the energy mix of an area, the load factor of other stations must fall, raising their average cost per MWh of power delivered. In the short term, the extra capacity can reduce wholesale prices (a phenomenon known as the Merit Order Effect), implying that at least part of the cost of supporting renewable generators[18] is borne by conventional generators. In the medium term, those

[17] It should be noted that a number of oil-fired stations in the UK are soon to close under the Large Combustion Plant Directive, eliminating flexible capacity that would be very useful in balancing the impact of wind power, but would not have run very often while doing so, and hence would have emitted very little SO2 (a major precursor to acid rain). The cost per tonne of the emissions saved is likely to be high.

[18] Most renewable generators (except large hydro plants) have costs that are higher than the current cost of wholesale power in Europe, and so must receive additional support if they are to be financially viable. It should be pointed out that the academic studies which showed that the merit order effect was approximately equal to the subsidies paid to wind power in Germany and Spain were written before the

generators must receive enough revenue to cover their costs, or they will start to close their most expensive plants, reducing the capacity margin and pushing prices back up.

In the long term, generators will need to invest, and the mix of stations that they choose should reflect the changing pattern of the load that they have to meet. With a lower load factor, there should be fewer base load stations, and more peaking stations with low fixed costs. Those countries that wish to invest heavily in nuclear power will find that the number of stations still able to run for 7-8,000 hours a year has fallen. The amount of capacity that will only be needed for a few hundred hours a year will rise.

It is best if these short-term peaks in demand can be met without incurring large fixed costs. Old power stations, with capital costs that are already sunk, can be ideal.[19] If new capacity is required specifically to meet demands at the top of the load-duration curve, this is best done by peaking plants such as open cycle gas turbines or even diesels. Their emissions per MWh will be high, but they will produce few MWh.

Another possibility is to reduce demand for a short period when it is at its highest – in many countries, the daily peaks in demand last for only an hour or two, implying that if enough consumers can postpone part of their consumption for a short period, the adjusted pattern of demand will be much easier to meet. Industrial consumers in (some) process industries are able to postpone or interrupt production to avoid the highest prices, and / or receive payment, and most system operators take advantage of this type of demand response. In future, smart grid technologies could allow communication with all electricity consumers, offering the chance to adjust the operation of loads with thermal inertia, such as fridges, air conditioning and water heating, in ways that consumers should not notice. These technical possibilities already

massive expansion in much more expensive solar power – the merit order effect is very unlikely to offset these costs.

[19] The key requirement is that the old stations have already been displaced by superior alternatives that are profitable in their own right – there is no point in building new capacity solely to allow older stations to act as peaking plants.

exist; it is not clear that the business models and regulatory systems to facilitate their widespread use are yet in place. EU countries are deploying smart meters to all customers (at great expense) but these will not be able to support demand management in response to unforeseen events without frequent two-way communication with the grid – more frequent than some countries are requiring.

Another longer-term solution could lie in energy storage. This relies on buying power when demand is lower and it is relatively cheap, in order to release it at times of high demand (or low renewable output) and high prices. Pumped storage hydro stations have used this business model for decades, but only some countries have suitable sites, and their construction costs are very high. Other technologies, such as various kinds of batteries, super-capacitors or compressed air storage, are being developed. To be commercially viable, they will need to have low fixed costs or a high round-trip efficiency[20], and preferably both. Some storage technologies will also be able to provide reserve power (substituting for power stations) or to relax constraints on the transmission and distribution systems (by releasing power on the far side of a potential constraint as soon as an actual problem appears) and doing this could provide additional revenue streams – as long as conflicts between the different possible uses can be avoided. Storage is not a panacea, however – it has costs, just like building power stations.

The size and geographical diversity of Europe offer another possibility. At times when one region has a relative shortage of generation, other regions that are using a different technology, or have a different weather pattern, are likely to have a surplus. As long as sufficient transmission capacity exists, power can be exported from the surplus regions to those where supplies are short and prices are higher. The trade between Denmark

[20] The round-trip efficiency of a storage system measures the amount of energy that can be taken out of the system, relative to the amount originally put into it. It is the product of the efficiency with which the device is charged and that with which it is discharged.

and its neighbours is an excellent example of this – Denmark's net exports of power are above-average in those hours when its production of wind power is also above-average, and it then imports the power back again in hours when its wind output is below-average. To a large extent, it uses the stored water in the Norwegian hydro system to offset the variability in its own wind generation. This works well to accommodate fluctuations from the relatively small Danish system – it is unlikely that Norway could provide as good a service for the much bigger UK, even if sufficient transmission lines could be built.

What combination of these approaches will prove most cost-effective? Researchers have produced a wide variety of scenarios for the future of the European power system, and yet the future will probably surprise us. However, the most effective approach will probably use a mix of most of the options (peaking plant, demand response, storage and transmission) just described. At this stage, it is important to preserve the flexibility to be able to develop each of them, even those that currently look unpromising. There may be little need for storage in the UK electricity system of 2020, for example, but Strbac et al (2012) have predicted that by 2030, it would bring significant benefits. It is unlikely that the requisite capacity could be developed in under a decade from a standing start, implying that work must start before the need for the technology has become pressing. Similarly, transmission capacity takes a long time to plan and build. Regulators will need to ensure that transmission companies make an early start on the key projects, and that consumers fund this work. Storage or transmission may reduce the amount of money needed for peaking plant, but they are not free, and we should not pretend that they are. More efficient coordination can increase flows over existing transmission lines and make use of spare capacity to facilitate a few years' worth of renewables expansion, but the transfers envisaged in the 2020s and beyond will require massive investment.

Whatever investments are made, operating the transformed electricity system will be a significant challenge for transmission companies. The pattern of demand facing centrally dispatched generators, demand response and storage facilities will be more variable and less predictable, placing a premium on forecasting skills. System operators will need to hold more plant in reserve than at present. Storage facilities, and storage-based hydro plants (including pumped storage hydro) can be kept ready to start (or increase) generation at short notice with no direct emissions, but running fossil stations part-loaded does incur an emissions penalty – which is very small compared to the saving from the renewable generation that is being backed up.

An increased volume of long-distance transfers raises challenges of liaison between system operators. Some of the biggest black-outs of the past have occurred when one system operator has been unaware of problems developing on a neighbouring system. In some cases, there is nothing that can be done to prevent a cascading failure from spreading over system borders, but in other cases, it might be that operating in a more resilient manner would be enough to stop the problem from spreading. It should be noted, for example, that the PJM system remained on during the failure that blacked out its neighbours in Ohio and New York in August 2003. System operators will also need to develop ways of prioritising power flows at times when there are more transit requests than they can safely accommodate.

4. 5. The Cost of Decarbonisation

Most low-carbon forms of generation are currently more expensive than electricity from fossil fuels. This may change in future, if the prices of fossil fuels or of carbon dioxide rise significantly, or if technological progress reduces the cost of nuclear or renewable generation. However, any prediction of the amount by which the cost of a low-carbon system will differ from that of business as usual would be correct only by accident.

Despite that, much can be said about the ways to minimise the cost of decarbonisation. Research, development and deployment of a wide range of technologies is needed to ensure that we not inadvertently locked in to a mix of sources that are currently least-cost but may not remain so, or may not be available in the quantities required.

The markets in which electricity is traded must be as efficient as possible, in the sense of achieving a dispatch which is as close as possible to the lowest-cost combination of plants that can meet demand. The EU is moving towards a target model for electricity markets, in which the operators for adjacent markets will seek to ensure that power always flows from a lower-priced to a higher-priced area if transmission capacity is available, and that transmission constraints will be reflected in different prices each side of the congested boundary. EU markets differ from the design adopted in parts of the US, however, in that the market operators are distinct from the system operators responsible for ensuring the smooth operation of the grid. American Independent System Operators run a linked series of auctions to buy both electricity and ancillary services such as reserves, setting prices which may differ for every node on the grid. The greater degree of integration and the more finely-tuned price signals suggest that the US market design offers a more efficient dispatch than the one common in Europe. Generators to the west of the PJM system had the opportunity, and the commercial incentive, to sell power into that market for many years, and the common perception was that power flows across the border were efficient. In the year after that area was formally brought into the PJM market, and the generators were full participants in its auctions, the flows roughly doubled. This experience suggests that Europe would gain from having a relatively small number of large market areas. Politicians and regulators must have the courage to argue against the vested interests of market operators. We need market operators, but must recognise that they make their living from transactions costs. Minimising those costs is clearly desirable, as long as we avoid throwing out the baby of efficient trades alongside the costly bathwater.

Many forms of renewable power have variable costs practically equal to zero, while nuclear plants can be inflexible, with high minimum generation limits. If a lot of renewable power is available at times of low demand, this could push prices down to zero, or even below. The lower prices would be reached if renewable generators receive output-based subsidies that they would have to give up if they reduced output to allow other, inflexible, plants to continue running. If the system operator has to pay the generator the value of the subsidy foregone before it is willing to reduce output,[21] this will produce a negative price. If the renewable generator has an absolute right to sell its power (under the EU rules on priority access) and is unwilling to negotiate a price at which it gives up this right, then the system operator may need to take actions that would be even more expensive, shutting down the inflexible plant until demand has recovered sufficiently to absorb its output. The rules for priority access – or the way in which they are interpreted – should be reformed before even more generators are built with a belief that they are entitled to impose costs on the rest of the system.

Electricity markets can cope with occasional negative prices – the Australian markets have negative prices when large coal-fired plants need to avoid being turned off overnight, and are willing to pay for this. Most transactions in the short-term markets are hedged with longer-term contracts, and the prices in these contracts will take account of the expected prices in the short-term markets. If negative spot prices are expected from time to time, this will tend to be reflected in the price of longer-term contracts, making investment in plant that has to run at those times less attractive, and helping to resolve the problem.[22] If Europe ever got to the point where prices were predictably negative at certain times of the day or year, this might be more disruptive.

[21] In an electricity balancing or real-time market, a generator that reduces output is effectively buying power back from the system operator, and has to pay the operator for the power that it "receives" in this way.

[22] Note that it may still be efficient to have some negative prices if the other advantages of the inflexible stations (such as low variable costs) outweigh this cost of their inflexibility.

Consumers able to buy at those prices would actually have an incentive just to waste electricity; it would certainly be efficient to use the power to heat water for later use. This is a kind of energy storage; if electricity storage technologies are deployed on a large scale, this might help to mop up the surplus power. In the short term, that could eliminate the negative prices, but in the longer term, the altered load shape creates the opportunity to build more of the inflexible plant, and negative prices could recur.

Moving away from output-based subsidies (perhaps switching to capacity-based ones) would allow renewable generators to signal their true marginal costs, and create a more efficient spot market. The disadvantage is that the more renewable generators' revenues depend on (volatile) market prices, the greater the risks they have to bear. Researchers for the European Commission have found that well-designed feed-in-tariffs, offering renewable generators a fixed price for their output, have been more effective than schemes that offer a supplement to the market price for power, in terms of the proportion of a country's potential that has been developed. They are also more efficient – the generators make lower profits, the best proxy for providing better value in a context where the cost of renewable power varies between countries. Profits can be lower without making investment unattractive, if the lower risks mean that generators have a lower cost of capital. If the feed-in-tariff were to lead to a significantly less efficient pattern of wholesale market prices, this might reverse the comparison, but it might also be possible to reform the tariff to create better signals. If the generator could claim the tariff, not only for its actual output but also for potential output that the system operator had required it to "spill", it would no longer have a need for negative prices.

4. 6. Wider Economic Consequences

What are the wider economic consequences of a move to a low-carbon electricity system? It is relatively easy to calculate the number of jobs that could be created in building and operating low-carbon generators, and they can be substantial. The proportion that will be European is much harder to calculate, given the rapid shift in the PV industry from German to Chinese manufacturers, for example. Furthermore, if less electricity is generated from conventional power stations, jobs will be lost in that part of the industry. Press releases on “green jobs” typically ignore those job losses.

The really difficult calculation concerns the number of jobs that might be affected by higher energy prices. Higher energy prices will make some European firms less competitive, in the sense that they will find it harder to sell their products at a profit. For a firm to be profitable, and hence competitive, it must offer a combination of cost and quality that compares (sufficiently) well to those of rival firms. If the EU adopts low-carbon policies that raise energy prices in Europe, and other countries do not, then energy-intensive European firms will be at a serious cost disadvantage, for a given exchange rate. The caveat about the exchange rate is important, for if an entire currency area was “uncompetitive”, then it would tend to have a strong trade deficit which would put downwards pressure on its exchange rate. This would tend to make its companies more competitive, until a point is reached where some sectors are net exporters and some are net importers. [23]

It must be noted that the importance of energy costs varies widely between industrial sectors. Process industries such as bulk chemicals, metal refining and smelting, and paper production are generally energy-intensive, whereas energy is a much smaller proportion of the cost of most engineering firms, or services businesses. Not all products are actively traded over long distances, for transport costs might simply be too

[23] An individual country or region within a currency area could have many competitive firms and a trade surplus without affecting the exchange rate if other regions had deficits – other policies might be needed to deal with any resulting imbalances. However, since the EU has a unified set of climate and energy targets, and is aiming for a single market in energy, the resulting cost pressures and changes in competitiveness should affect all firms (of a given type) equally, whatever their location. Regions with a strong concentration of energy-intensive industry might come under extra pressure, however.

great to make it worthwhile. However, some European firms in sectors with a high level of international trade will see significant increases in their costs. These firms risk a serious loss of competitiveness.

If this started to affect the Eurozone's trade balance with the rest of the world, and the exchange rate depreciated to offset this, then firms in sectors that are not energy-intensive might become more competitive. However, the danger is that it is far easier for an uncompetitive sector to collapse than for firms with a price advantage to build up production and gain market share. It is better to take action to avoid the collapse, while recognising that energy-intensive sectors will rightly be placed under pressure in the move to a low-carbon economy. This pressure should be based on consumers shifting their demand away from products that are becoming more expensive, which would be a gradual process compared to the sudden loss of business to foreign rivals.

There are several policy options available to stop such a collapse. Under a system of border tax adjustments, tariffs are charged on imports from countries that have not imposed a sufficient carbon price on their own energy users. The tariff would be based on the energy-intensity of the product and the carbon-intensity of the exporting country's energy system. These calculations would have to be somewhat approximate, particularly if the carbon emissions associated with the production of intermediate inputs are to be counted. Nonetheless, the resulting tariff does not need to be precisely calibrated if it is to protect EU firms from an overly dramatic loss of market share.

The advantage of a border tax adjustment is that prices within the EU would still signal the carbon content of the industry's production, giving incentives to reduce consumption of those products. Companies also face the correct price signals of the relative cost of energy (including its environmental externality) and other inputs, giving an incentive for efficient production. The disadvantage is the risk of trade disputes if other countries believed themselves badly affected by the tariff and tried to challenge it at the WTO. Challenges there would be stronger, the more approximate the methodology that was being used to calculate the tax adjustment on imports.

This risk would be much reduced if the EU used internal measures to compensate its industry. The EU Emissions Trading Scheme (EU ETS) has given free permits to many industrial plants, even in Phase III when power generators must buy all of their requirements. Even free permits still carry an opportunity cost, for they could be sold if not required, and so the industrial companies have an incentive to cut their emissions. Their profits are protected, however, even if they do not reduce emissions, and this provides a reason to keep a plant open in the face of competitors with lower energy costs. Foreign producers will still have lower marginal costs than EU firms, however. This is likely to mean more imports and a lower product price inside the EU than if a border tax was used. Demand for the product will be higher, and so will the world-wide emissions from its production.

A final possibility is to exempt heavily-affected sectors from the EU ETS entirely. This allows them to compete on a level playing field with foreign firms, but does nothing for the environment – consumer prices do not reflect the carbon embodied in the product, and the EU firms have no incentive to cut emissions.

The approach adopted in Europe is the middle ground. Sectors that are relatively open to extra-EU trade (as measured by exports and imports relative to production) and those likely to see high permit costs are given many of their permits free of charge, although the proportions will fall over time. Distributing free permits in this way helps the sectors that are directly covered by the EU ETS, but it is not a realistic mechanism to assist sectors that have few direct emissions, but a heavy use of electricity. Those companies will see their power bills rise as the electricity sector passes on the cost of carbon permits. Finding an efficient way to compensate those companies – while not overcompensating firms that do not face a significant problem from higher electricity bills – would be challenging.

At the household level, there is a related problem, that of fuel poverty. While many European consumers spend only a small proportion of their disposable income on energy, a significant (and growing) minority need to spend ten per cent or more – a level often defined as "fuel poverty". Fuel poverty is often caused by high needs – poorly insulated houses, for example – as much as by low incomes. In those cases, measures to improve energy efficiency can have the double benefit of reducing fuel poverty and cutting carbon emissions. The proceeds from selling ETS permits should be spent on energy efficiency measures targeted at fuel poor households and electricity-intensive firms.

4. 7. Conclusions

Adding a large amount of renewable capacity to Europe's generation mix will have important consequences for the other stations on the power system. More of those stations will be needed for relatively short periods, putting a premium on flexibility. Wholesale power prices may become more extreme, with periods of very high and of very low (even negative) prices. Market or regulatory mechanisms that allow rarely-used stations to cover their costs, and encourage cross-border trade to smooth fluctuations in renewable output will be important in reducing the cost of absorbing intermittent renewable sources. Energy storage can play a role if cost-effective technologies can be developed. We should not delude ourselves that the costs of transmission and storage will be low, however.

These changes are very likely to increase energy prices, unless we find ourselves in a world where fossil fuel prices are uncomfortably high in any case. The capacity of Europe's firms and households to cope with those higher prices varies. For many sectors, energy is a small part of total costs, and higher prices could be absorbed or passed on to customers with little impact on demand. For a few sectors, the cost increases could lead to a dramatic loss in international competitiveness, and policies to offset this should be considered. A mechanism for border tax adjustment is likely to be the most efficient of these.