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AN EVALUATION OF THE NEW BRITISH ENERGY POLICY AND ITS IMPLICATIONS FOR THE EUROPEAN UNION

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Electricity Investment: An Evaluation of the New British Energy Policy and its Implications for the European Union

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Abstract

Traditionally, the electricity market has been characterized by vertically integrated monopolies due to the special features of this commodity, such as non-storability in the longer term, the physical laws requiring instant equation of supply and demand and the need for a complex and integrated network, controlled by a system operator. Despite these features, however, a wave of reforms promoting competition has been initiated in most markets, including the US and Europe, accompanied by regulation.

In this paper we offer an overview of the current electricity policy debate taking place in the UK, which may pose the basis for a rethinking of the dominant policy paradigm. We review the technological and economic features of electricity markets, focusing on the rationales underlying the reforms put in place in the European Union and highlighting the impacts and potentially problematic consequences of liberalization in terms of investment and infrastructure, related to overarching economic, social and policy goals, focusing on the implications of environmental and climate-change mitigation policies as well as poverty reduction issues. The paper analyses the possible consequences, in terms of reforms and regulation of the electricity industry, of these new goals, suggesting that they may be relevant for the electricity industry in the EU.

Keywords: Electricity market; Energy policy; Investment

JEL Codes: Q40; Q48; E22

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1. Introduction

Great Britain is the European country where electricity reforms started earlier, in the 1990s. Its example influenced both energy policy-making at the EU level and national legislation in many countries. After more than twenty years from the reforms, the situation of the UK is less than satisfactory in terms of long-term investment, environmental sustainability, and social affordability of supply. The UK Department of Energy and Climate Change (DECC) White Paper "Planning our Electricity Future" (2011) proposes to move away from *market fundamentalism* (Rutledge and Wright, 2010), as it acknowledges that the existing arrangements do not provide the right price signals to operators, and that a capacity gap has been created, particularly in the perspective of the de-carbonization of the economy. The White Paper also suggests that there are social affordability issues to be addressed in the future. The new framework includes tenders for new investment directly managed by a central body, a feed-in subsidy for renewables, and stricter quantity regulation of emissions. The new infrastructure needs are thus addressed by regulatory mechanisms, with an active role for the government, a role that deeply alters the previous market-based approach.

This paper evaluates the proposed approach and shows that the recent dramatic change of UK energy policy should be carefully considered by EU policy-makers, as it suggests that the perspective of the Third Package[2] is possibly inadequate to solve the long term investment challenges of the electricity industry, particularly if the objectives of de-carbonization, security of supply, and social affordability are to be met.

The structure of the paper is as follows. First, we recall the influence of British energy reforms on the current regulatory approaches in the EU. Second, we focus on some features of the electricity industry in Britain, compared with selected EU countries. The third section presents and discusses the rationales behind the recent UK Energy Policy White Paper. Fourth, we discuss the paradigm shifts in terms of the core technological features of the electricity industry, and their implications for long-term investment. Section 5 concludes and suggests that the change of electricity policy in the UK points to the need of a reconsideration of the EU regulatory framework.

2. Electricity reform paradigms: the UK and the EU

Until very recently, after privatization and liberalization in the UK in the 1990s, and following the EU energy directives, it was claimed that a reform paradigm had emerged in Europe, or

[2] http://ec.europa.eu/energy/gas_electricity/legislation/third_legislative_package_en.htm

> ‘a measure of consensus over some generic measures for achieving a well-functioning market-oriented industry’ (Jamasb and Pollitt, 2005, p.2).

For the first time in the history of the electricity industry in Europe a unique cross-country policy reform pattern was unanimously advocated by international organizations, notably the European Commission, the OECD, or the World Bank and EBRD for the transition economies. Until the 1990s, all or most of the activities in the electricity sector were vertically integrated in Europe, with state or municipally owned enterprises playing an important role. The market was highly regulated, with limited opportunities for users to switch to alternative suppliers. There was no third party access to the transmission grid. This integrated pattern was the deliberate result of policy reforms that consolidated the mostly private and fragmented European electricity industry in its earlier stages. The governments’ view until the 1990s was that for economic, political and social reasons the previous pattern, mainly based on regional private monopolies or collusive oligopoly, was either inefficient or undesirable (Millward, 2011). The British reform in the 1990s has been spurred by different policy goals, including especially pro-competitive arguments that link privatizations, liberalizations and the creation of competitive markets as essential preconditions leading to higher efficiency and overall to gain for final consumers (Littlechild, 2000; Newbery, 2000). Historically, the transition towards a more competitive environment in the electricity sector has started with the creation of wholesale spot markets, which have been characterized by a certain degree of variability, across countries and times, in relation to the rules governing them. While the basis for price setting is related to marginal cost pricing, with special attention to the peak-load plant, markets can be designed as gross pools, where the price is set by the rules of supply and demand, and net pools, where generators may enter in long term contracts with retailers.

The liberalization process in the UK started in 1989 with the Electricity Act and was completed in 1999. The reform process included the breakup of the Central Electricity Generating Board (CEGB) into two generating companies (PowerGen and National Power) and the national Grid Company. So National Grid, PowerGen and National Power were privatized in the early 1990s together with a network of RECs (regional electricity companies).

The privatization process ended in 1995, in England and Wales, but Scotland and Northern Ireland followed a different path. As regards the market opening at its beginning, the right to choose the electricity supplier was granted only for the major users, but the threshold level was progressively reduced, reaching a complete liberalization in 1998. The Electricity Act also established the introduction of a wholesale market and the complete separation of the transmission activity from generation. In the network services (transmission and distribution) the price was regulated by the price cap, under the control of OFFER, a regulation agency, now OFGEM.

The British example was of paramount importance in shaping the position of the European Commission. The overall aim of this reform process at the European level has been to enhance competition in the electricity market, through the entry of new generating and retailing firms, and to extend the relevance of national markets through the creation of an EU-wide market. The underlying social goal has been to benefit from the efficiency gains of competition in terms of lower collusion and abuse of dominant position, which should lead to benefits to consumers and to society as a whole, including better international cooperation to increase security of supply (Pollitt, 2009).

The EU directive of 1996 (Directive 96/92/EC) set the stage for the creation of a European internal market for electricity, but was lacking in terms of concrete provisions of market design. To this aim, the 2003 directive (Directive 03/54/EC) provided specific indications on unbundling of transmission and distributions systems, established an independent national regulatory agency and required free entry in the generation segment of the industry. Finally, the 2009 directive (Directive 09/72/EC) has been prepared taking stock of the progress needed to achieve the goal of the internal electricity market, and includes further requirements for unbundling of transmission assets and the creation of transmission system operators within integrated groups. The overall current European situation is one of increasing compliance with the Directives and market opening is ongoing in most of the EU countries. However, the assessment of the market impact of this reform process is still not so clear cut, as we shall discuss below.

2.1 The reform paradigm

The electricity paradigm is usually simplified as suggesting three parallel reforms: privatization (sale of existing publicly owned electricity firms and licensing of private generators and suppliers), unbundling (associated with incentive regulation of the networks, third-party-access, establishing and independent regulator), and liberalization (i.e. allowing entry and competition in both generation and retail).

The reform ingredients are summarized as follows by World Bank (Lampietti et al., 2007):

a) De-monopolization and regulation: unbundling vertically integrated monopolies to foster competition in generation and supply; privatize and shifting the role of the state from owner to regulator; promoting entry by foreign investors; establishing transparent energy markets; building regulatory capacity

b) Prices and fiscal policy: promote fully cost-reflective prices; elimination of production subsidies; taxation based on externality correction; enforce metering and collection of bills; closing uneconomic plants
c) Foreign trade: opening markets to imports; eliminating taxes on fuels and electricity; strengthening regional trading arrangements; expanding trans-boundary energy connections
d) Investment policy: rely on energy companies to sustain investment, not on the public sector budget; support energy efficiency; increase flows of foreign capital with appropriate measures
e) Social protection: safety nets for the redundant staff; social service functions to be transferred to local governments, not to companies; support to the poor through lifeline tariffs or means-tested subsidies (abolish cross-subsidies)
f) Environmental protection: supporting environmental assessment; introducing emission norms; mainstreaming new environmentally friendly technologies.

In this perspective, the driving idea behind privatization of electricity companies is that public ownership is intrinsically less efficient than private ownership, because of an incentive argument. In turn, the rationale for unbundling is to separate the potentially competitive stages from those with natural monopoly characteristics, which may need some public regulation. Eventually, liberalization would bring market forces in the industry, and competition would deliver production and allocative efficiency, hence lower prices, or lower mark-up over costs. Having highlighted the main ingredients of the reform paradigm, we now turn our attention to the UK experience in the past twenty years, since, according to Rutledge and Wright (2010), Great Britain has been the laboratory of this approach which has been the basis for the EU reforms.

3. Electricity industry in the UK

We start by presenting a very brief description of the British electricity industry, compared with the situation in selected EU countries, to gain a better understanding of the policy reforms that have been implemented and their long term implications for investment.

In terms of self-sufficiency, after 30 years of being an exporter (Bolton, 2010), the UK is now a marginal net importer of electricity since 2004, with net imports contributing 0.7 % of electricity supply in 2010 (DECC, 2011). The UK mainly imports from France and exports to Ireland[3]. This insular, until recently near to self-sufficiency, perspective (combined with the domestic availability

[3] European Energy Regulators (2011).

of natural gas) should be compared with the situation in continental Europe (see Table 1). International trade of energy is usually small in most EU countries, but not in all of them and has been growing in recent years[4]. This increase is related to an overarching EU goal of creating an internal electricity market, as embodied in the various energy packages. As an illustration of this objective, an implication of the adoption of Regulation (EC) No 663/2009 has been the selection for EC funding of 43 additional projects for gas and electricity infrastructure, with a specific focus on electricity interconnectors, which will in turn foster intra-EU trade.

	1990	1995	2000	2005	2006	2007	2008	2009
Imports	1105.89	1095.54	1265.67	1455.54	1494.14	1464.61	1498.16	1407.18
Exports	350.96	377.6	440.57	472.09	485.07	478.16	483.88	463.58
Net imports	754.93	736.08	825.09	983.45	1009.07	986.46	1014.28	943.6

Table 1: Import dependency in EU-27 (Mtoe)

Source: Eurostat

France for many reasons can be considered orthogonal to the UK, as until recently it was reluctant to adopt privatization, liberalization, and unbundling. Moreover the country, entirely lacking fossil fuels, pursued an energy policy mostly based on nuclear power. In contrast to the UK, France is now the most important European net exporter of electricity, with 46 electrical interconnectors linking it to other countries in Europe. Roughly 12% of the electricity produced in the country is sold to neighbouring EU countries such as Belgium, Germany, Switzerland, Italy, Spain and the UK[5].

Turning to ownership, electricity privatization in the UK has been reviewed by Parker (1999) and critically assessed by productivity studies such as Newbery and Pollitt (1997) and O'Mahony and Vecchi (2001). Florio (2004) suggests that productivity changes were modest, while Rutledge and Wright (2010) conclude that the expected efficiency impact of privatization on total factor productivity (TFP) in the UK has not been confirmed at all. British privatization was not imitated

[4] With the exception of 2009, possibly due to the financial and economic crisis.
[5] RTE Electrical Energy Statistics for France (2010), authors' elaboration.

universally in Europe, as we shall see below. Among the core shareholders there are still state or governmental bodies in four out of the seven major European electricity companies[6].

To analyze the main trends in regulatory reform, we consider a summary reform index, based on an OECD international database that runs from 1975 to 2007, the former REGREF, now ETCR, regulatory dataset. It is publicly available and collects information about indicators of privatization, liberalization and unbundling across all the OECD countries in energy, transport and communication (for details see Conway and Nicoletti, 2006).

1980	***Non liberalized***	***Liberalized***
Private	Belgium	
Mixed	Germany, Spain	
Public	Austria, Czech Republic, Denmark, Finland, France, Greece, Hungary, Ireland, Italy, Luxembourg, Netherlands, Norway, Poland, Portugal, Slovak Republic, Sweden, United Kingdom	
2007	***Non liberalized***	***Liberalized***
Private	Belgium	Germany, Spain , United Kingdom
Mixed		Finland, Hungary, Italy, Luxembourg, Norway, Portugal
Public	Poland, Slovak Republic	Austria, Czech Republic, Denmark, France, Greece , Ireland, Netherlands, Sweden

Table 2: Public Ownership of largest company and wholesale market liberalization, selected OECD countries
Source: ETCR. Authors' elaboration

By analyzing the ETCR sub-indicator for public ownership in electricity (Table 2), it appears that in 2007 many European countries are still characterized by a high degree of public ownership. This fact should be stressed as it demonstrates that liberalized markets (verifiable through the ETCR sub-indicator on the existence of a liberalized wholesale market, Table 2) do not wipe away the possibility of direct involvement of public bodies in electricity generation, transmission, distribution and supply of electricity (Haney and Pollitt, 2010).

[6] Namely: E.ON, GDF Suez, EDF, ENEL, RWE (Thomas, 2010).

The ownership pattern following privatization in the UK proved to be less than attractive for domestic investors, and evolved into wide acquisitions from abroad. In fact, the firm with the largest market share in the UK is NPower RWE, formerly Innogy, and is a division of RWE AG, a privately owned listed German multi-utility company. The situation is again radically different in France where EDF (Electricité de France) is owned at 84% by the French government through the Caisse des dépots et consignations.

Following the reform process aiming at the creation of an integrated and competitive European electricity market, the market structure in electricity generation has distinctively moved away from integrated local monopolies towards a more diffused market structure. This trend can be seen by looking at the evolution over time of the market share of the largest generator in EU countries, between 2000 and 2009 (Figure 1).

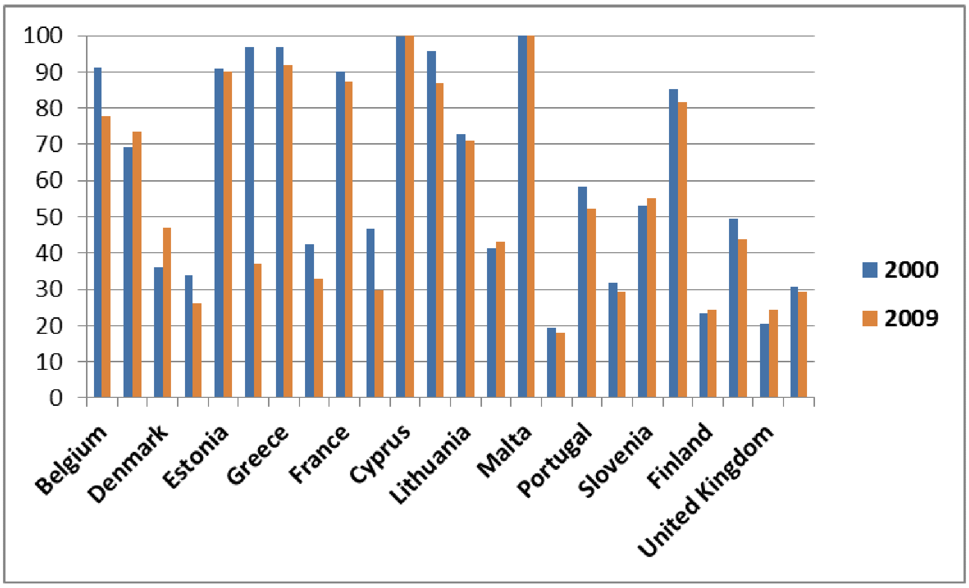


Figure 1: Market Share of the largest generator in the electricity market

Notes: Data for Romania and Slovenia in the first column refers to 2004

Source: Eurostat

In spite of market opening, however, the European electricity market is still deeply influenced by the presence of a small set of large companies, the "Seven Brothers" (Thomas, 2003 and 2010) which, after a process of mergers and acquisitions are made up of five truly global European companies and two smaller firms with significant operations in more than one country. Table 3 provides financial statistics for these companies in 2009. Britain is no more represented in this emerging oligopoly.

	Shareholding	Turnover €bn	Net income €m	Worldwide workforce
GDF Suez	35,6% state-owned	79.9	4477	242714
EON	listed	81.8	8645	88227
EDF	84,7% state-owned	66.3	4088	164250
ENEL	31,4% state-owned	64	5395	81208
RWE	listed	47.7	3571	70726
Ibersdrola	listed	24.6	2939	32711
Vattenfall	100% state-owned	19.8	1300	40026

Table 3: The Seven Brothers: Major electricity companies in the EU, 2009

Source: adapted from Thomas (2010)

There is thus no evidence that market structures are converging to a unique pattern in the EU, even if there are some common trends driven by the policy initiative of the European Commission which are related to the presence of high market shares and concentration. Zooming in on the situation in the UK after the reforms, Sweeting (2007) finds that in the England and Wales Electricity Pool an initial high degree of market concentration was in fact followed, after the restructuring and reform process, by the exercise of market power of the main firms in the market, even though indices of concentration were decreasing. The reading of this empirical result leads the author to conclude that the generators' behavior was related to tacit collusion or price raising strategies. Newbery (2007) stresses the importance of reducing concentration as well, in order to ensure lower price-cost margins. In fact, this suggest that powerful factors drive the industry to oligopoly.

After the process of liberalization the number of companies producing electricity in the UK increased considerably passing from 6 to 47 in two years, but then there have been however processes of re-integration, mergers and acquisitions that have increased the concentration of the market. Generation consists of approximately thirty private entities (DECC, 2011), many of which are joint ventures, with only 7 having a market share above 5%. In particular the market is dominated by three foreign-owned firms: Npower (RWE) (18.4%), E.ON (15.8%) and EDF

Energy[7] (15.7%)[8]. The retail market is characterized by the presence of six big suppliers[9] with an individual market share above 5% and which account for, on aggregate, 99 % of supply (HM Treasury, 2010). The ownership of the transmission grid is divided between four different private companies. In the UK there are also many "broker" type services which act to help customers to choose the best contract structure offered by the main suppliers.

The main development in recent years is the greater degree of vertical reintegration between the main producers and supply companies,[10] and this fact poses difficult regulatory issues.

In general, in the EU, concentration in the industry remains high, with the largest three generation firms or the three largest retailers, controlling more than 60% of the market in the large majority of countries, whatever the extent of privatization, with two polar exceptions: the UK and the Nordic countries, the former with no public ownership left, the latter with mostly public sector firms.

Turning to the implications of market structure and reforms on prices, the price of the KWh in the last 17 years has oscillated in the UK between a minimum of slightly more than 0.08 and a maximum of 0.12 euro. In France the range has been between 0.09 and 0.10, in Germany between 0.12 and 0.14. Fiorio and Florio (2010, 2011) suggests that there is no clear evidence of simple correlation between price levels, and users' satisfaction with the price they pay, and reform indicators in 2007, or perhaps some positive correlation between price levels and dissatisfaction with prices and privatization. This fact is also related to concerns with fuel poverty in the UK, as discussed for example by Waddams Price (2011). Poggi and Florio (2010) find a positive correlation between some deprivation indicators, such as reported difficulty by households to pay the bill, and privatization, suggesting potential negative implications of reforms for consumers.

To sum-up, the British reform model of the 1990s, while in fact adopted by the EU legislation, has not been adopted by France, and has been subject to considerable modifications in several European countries, and the relative performances do not point to a better overall outcome of in the UK as compared to elsewhere. Liberalization has led to oligopoly in Europe, but with high variability across countries particularly in terms of vertical integration and public ownership. Particularly, there is no evidence that the British post-reform pattern has been more successful than elsewhere in terms of stability of the competitive arrangements, ownership, investment, trade, costs, prices,

[7] As of February 2009, British Energy is part of EDF.
[8] http://www.nationwideutilities.com/uk-energy-market-share.html
[9] The Big Six: E.ON, RWE Npower, SSE, EDF, Centrica and Scottish Power (HM Treasury, 2010)
[10] Serrales (2006).

social affordability and environmental sustainability (Florio, 2012). In fact, these issues have been pivotal in breaking the previous consensus, as we discuss in the next section.

4. The New British Energy Policy: A paradigm reversal?

The UK government has recently announced, twenty years after privatization and liberalization of the electricity industry, a radical change of its agenda. The new policy has been presented by the Department for Energy and Climate Change in " Planning our Electric Future: a White Paper for secure, affordable and low-carbon electricity" (DECC, 2011). The previous consultation document, the White Paper, its accompanying studies, the parliamentary debates by the House of Commons, Energy and Climate Change Committee (House of Commons, 2011), the reports by the regulator and by other stake-holders, the articles in the press on the announced reforms, have elicited a substantial amount of evidence and of interpretations about the state of the electricity industry in the UK. The consultation document (December 2010) received 274 responses by companies and associations, most of them publicly available. The intensity of the debate, the range of opinions, and the widely different reform proposals are justified by a relatively high consensus about a difficult situation of the electricity industry in the UK, which is clearly stated by the White Paper. We briefly summarize below the British Government's diagnosis and the new policy proposals.

In spite of lip service paid to the previous arrangements

> " Since privatisation in the 1980s, our competitive market and system of independent regulation has served us well, delivering reliable and affordable electricity" (DECC, 2011, p.5)

the Secretary of Energy identifies four unprecedented challenges:

a) In the next decade around 25% of generation capacity is expected to close and not to be replaced in the UK. This is due to ageing of plants, low new investment and to the fact that some polluting technologies are no more in compliance with the new environmental standards. According to some forecasts, the capacity margins will fall below 5% percent around 2020, and for technical reasons such a narrow generation reserve implies that blackouts and voltage reductions may become highly likely. Moreover, some of the new technologies, such as wind and solar, are intermittent. This fact has additional implications for security of supply, as the potential generation capacity will not be available in some weather conditions. Other non-carbon source are inflexible, such as nuclear power, which cannot be started up or closed down at short notice to respond to peaks of demand.

b) The industry pattern and future investment trends, as forecasted, are not compatible with the UK government's objectives to achieve a 15% of renewable energy in 2020, and to cut by 80%

carbon emissions by 2050. Without reforms, the industry is expected to pollute in 2030 three times the government's target for de-carbonization.

c) Electricity demand is expected to double in 2050 because of electrification of transport, heating and other sectors, in spite of policies for household and industrial energy efficiency.

d) Prices to final users are expected to rise considerably, both because of increasing prices of energy inputs and of investment, and because of the impact of environmental policies. For households, the electricity bill is expected to rise by around £200 per year (a 40% increase between 2010 and 2030). The impact is going to be felt particularly by the lowest income deciles (DECC (2011), p. 121), adding to the existing fuel poverty, but the rise would possibly be £160 with the reform (33% increase).

According to the White Paper there is

> "broad consensus that current market arrangements will not deliver the scale of long-term investment needed, at the required pace, to meet these challenges. Nor they will give the consumers the best deal. This is partly because of the sheer scale of the investment required. Up to £ 110 million investment in electricity generation and transmission is likely to be required by 2020, more than double the current rate of investment" (DECC (2011), p.6).

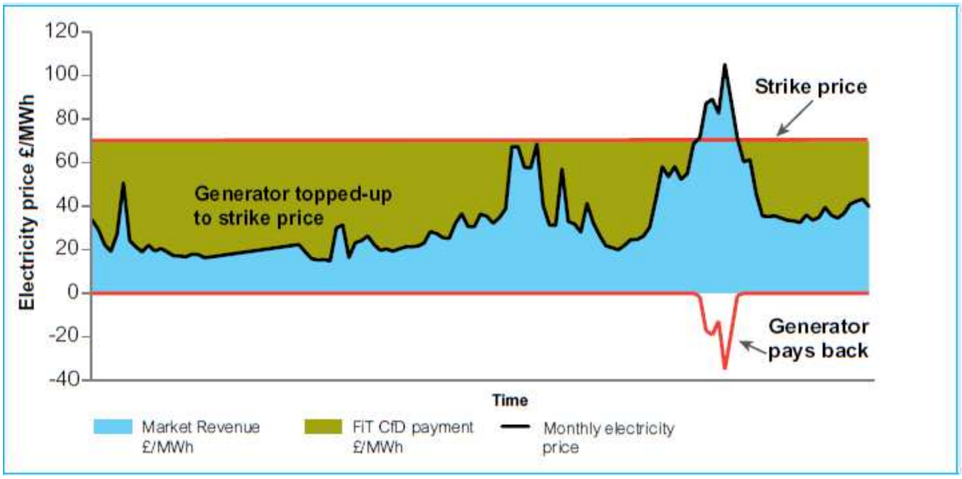
While there are dissenting views on these forecasts, the investors in their response to the consultation seem in general to agree that at the current prices and costs, they are unwilling to increase their investment in electricity generation, in transmission and distribution (according to OFGEM, £ 35 billion will be needed for the latter sections of the industry).

Whatever the precise proportion of the two causes of the decay of capacity and network infrastructure, i.e. lack of investment by the six major players and un-profitability of the low carbon technologies, in both cases, market prices have not provided the right incentives for long-term investment. Consequently, the new policy announced by the British government with its White Paper, will alter the pricing system:

> "… the social cost of carbon is not fully reflected in the market price as this does not take into account all the damage caused by climate change. The carbon price is also volatile and hard to predict,
> - making long term investment decisions more uncertain; and
> - the capacity and appetite of existing market participants to finance the unprecedented levels of investment needed is uncertain.
> - There are also likely to be insufficiently strong signals to invest in the level and type of capacity that we need in order to guarantee future security of supply. This is also due to the scale of investment and failures within the existing market." (DECC (2011), p.7)

Hence, the British government aims at radically changing the price signals by direct public intervention, through the four instruments of the Electricity Market Reform. These are:

a) Long-term contracts between a “central body” and low-carbon generators, a form of public procurement of electricity, based on Feed-in Tariffs with Contracts for Difference (FiT CfD). The central body will fix both a quantity of electricity (metered output) to be procured, a strike price (to be computed centrally) and a reference price. The latter could be different for different technologies, as it could be an average of price in the one-day ahead market (intermittent technologies), or in one-year ahead forward market (baseload power plants). The strike price (indexed to inflation) will be calculated by the central organization in such a way that when the reference market price is below the strike price, the low carbon generators (including nuclear) will be paid the difference between the reference and the strike price. If the reference price exceeds the strike price, then the difference should be paid back by the generators. The cost of the subsidy, or the claw back of the profit of low carbon will be passed to the consumer. Figure 2 shows the mechanism.



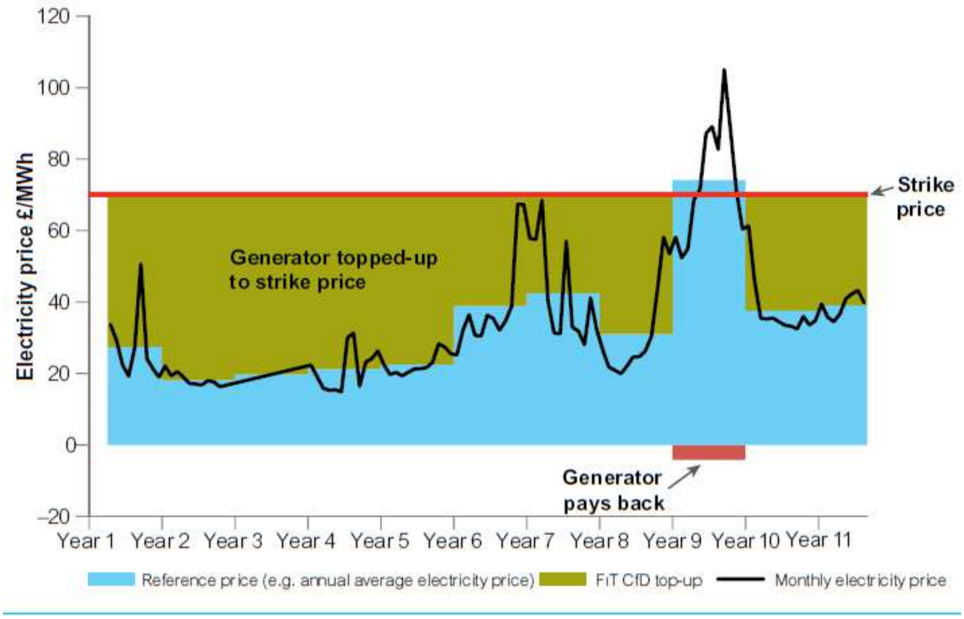


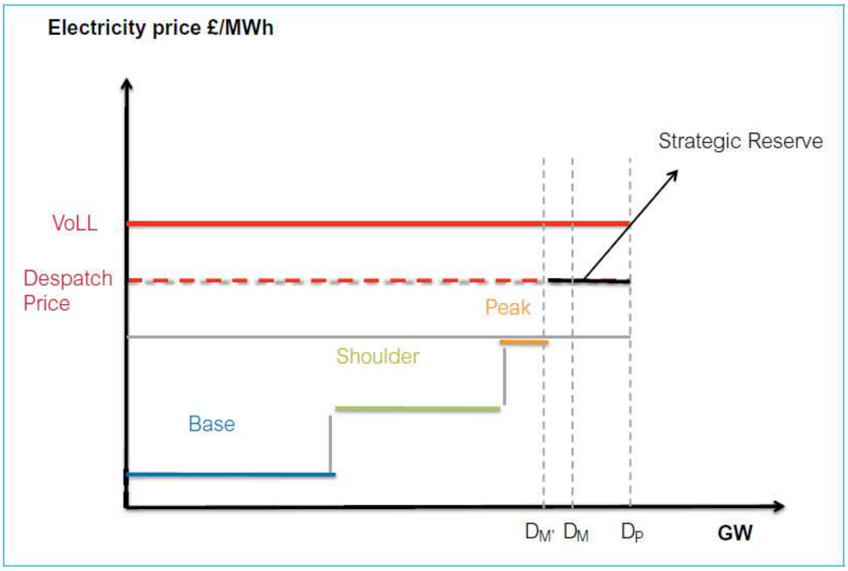
Figure 2: The operation of a baseload Feed-in Tariff with Contract for Difference (top panel) and the operation of an intermittent Feed-in Tariff with Contract for Difference (bottom panel)

Source: DECC (2011)

b) A Capacity Mechanism, where again a 'central body' will offer contracts to electricity companies to increase their generation capacity. Two options are considered. The first one is a targeted Strategic Reserve, where centrally procured additional capacity is set aside and used only in certain extreme circumstances, i.e. when there is a risk of service interruption. Alternatively a market-wide mechanism based on a financial instrument (a 'call' option) which would give an incentive to providers to invest in reliability of supply (or compensate users for service interruptions). Under both alternatives, also demand side operators, households and firms could receive the public incentive, e.g. to decrease their demand. Figure 3 shows the operation of the Strategic Reserve. System flexibility to accommodate the intermittent technologies, storage, and distributed energy (i.e. not using the main transmission lines) would also imply 'fundamental transformation' in the functioning and the network itself, and

> "Without guidance from the Government, there is a risk that uncertainty over the rate of change could lead to insufficient or inappropriate investment, resulting in the network being unable to deal with future challenges" (DECC (2011), p. 103),

hence the government will work with OFGEM to lead guidelines for network companies. The government will also promote work on storage technologies, interconnections and energy saving.



Notes:

D_P is the maximum demand which can be served by a market which has a Strategic Reserve, and the capacity of the Strategic Reserve itself, combined.

D_M is the maximum demand that could be served by a market with no Capacity Mechanism. Once a Strategic Reserve with a despatch price lower than VoLL is introduced, it will replace some electricity market generation, since it effectively caps the revenues that can be earned from times of peak demand.

$D_{M'}$ is the demand at which prices rise to the despatch price. When D_M' is reached the Strategic Reserve is despatched.

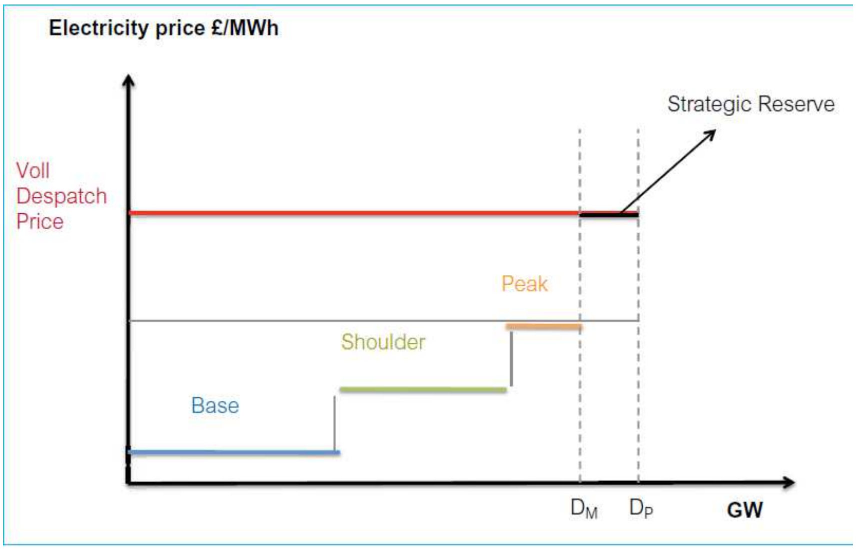


Figure 3: Operation of Strategic Reserve with economic dispatch (top panel) and Operation of a Strategic Reserve with last-resort dispatch (bottom panel)

Source: DECC (2011)

c) A Carbon Price Floor, starting in 2013, i.e. a stronger incentive for low-carbon technologies, additional to the EU transmissible certificates (Emissions Trading Systems), whose price is considered too low and volatile to provide the right signal to investors. The level of support will vary over the future years, starting from around 35 t/CO2, based on a price floor targeting of £k30. The proposal is based on the Stern Review (2006) position that it is socially desirable that polluters pay the full social cost of the externality associated with potential environmental damage, and that a carbon price would encourage investment in alternative technologies.

d) An Emissions Performance Standard, set at 0.450 Kg CO_2/kWh per year, in addition to the requirement that any new coal-fired power plant must use Carbon Capture and Storage technologies. Grandfathering, i.e. an exemption, is allowed for existing plants.

These measures should complement other demand and supply side policies, including incentives for energy efficiency to households and firms, smart metering, a government-sponsored Green Investment Bank (www.bis.gov.uk/greeninvestmentbank), and others.

A crucial aspect of the Electricity Market Reform (EMR) is that regulation by OFGEM will become in future only one element in a much more complex institutional framework:

> " It is likely that an organization at arm's length from the Government will administer the contracts. Other core functions to deliver the FiT and the Capacity Mechanism include: translating the policy objectives into technical requirements, delivering the contracts, data reconciliation, managing payments, and monitoring compliance and enforcement. The Government and the delivery organization(s), working jointly, will periodically evaluate according to a planning cycle clearly laid out in advance, their future strategy in the light of possible change in costs, technological developments, and new challenges to the energy system" (DECC (2011), p. 10).

A five-years planning cycle is envisaged. The role of the regulator will be changed accordingly, as

> "the current framework of broadly-scoped duties and weak guidance is very unlikely to be able to support a predictable regulatory environment that is coherent with the Government strategy…" (DECC (2011), p. 88).

Moreover the British government acknowledges that the electricity market is illiquid, and that OFGEM is trying (for the fourth time since the Pool) to achieve greater liquidity and remove barriers for independent generators. Market illiquidity is mainly due to the vertical re-integration of the market, with the Big Six who also own much of the distribution and supply, hence sell to themselves, in such a way that the unbundling of transmission and its regulation is per se not sufficient to establish a competitive market for generation.

4.1 Discussion and implications

Having described some aspects of the current electricity policy debate in the UK, some comments in our perspective are in order.

The core idea behind privatization and liberalization in the UK and elsewhere in the 1990s was to achieve a competitive market mechanism which had to be able to balance demand and supply through efficient, cost-reflective prices. Regulation, initially in the form of a price-cap, then only in the form of supervision of access to the unbundled transmission network, was seen as set to gradually decrease its role. The regulator was designed as an umpire or a policeman on behalf of the different stake-holders, with the task of ensuring fairness and level play field in the market game.

The future landscape designed by the White Paper and the EMR is radically different. As the White Paper title says, it provides for a *planned* electricity market, where one or more government sponsored central bodies will take crucial long-term decisions.

By computing the target capacity margin relative to long-term capacity, the government or an agent working for it, will actually take a decision on the total amount of investment needed. If the private sector does not deliver the investment, it will be the public sector that forces the desired level of investment simply by buying it on behalf of the consumers. At that stage, while this option is not mentioned in the White Paper, public procurement of generation capacity from the private investors may or may not be cost effective as compared to directly commissioning or acquiring some power plants, of the desired technology, by a Strategic Reserve agency owned or under the direct control of the Department of Energy.

In the public consultation some concern was expressed about the fact that a Capacity Mechanism could offer an incentive to some companies to set aside their capacity and be paid a long-term contract for this instead of actually generating electricity. In such a case, an even greater capacity would be needed, and it is not clear how great the intervention should be. In fact, there is a certain ambiguity in the White Paper as to the actual extent of the Capacity Mechanism. It seems that it is not intended simply to ensure the existence of an adequate margin (ten per cent of capacity is mentioned) but in fact, combined with the FiT, to ensure that the total volume of generation and of investment is adequate. The margin, after all, given an increasing demand, depends crucially on how much the private sector will invest, and if it will not invest enough, either the reference market price will increase significantly, or the government will need to intervene on a wider scale. Clearly a market approach would allow wholesale prices to increase until the profitability for investment is restored, but this in turn would not compatible with an affordability objective, as declared by the government even in the title of the WP. In fact, the government wants that the Strategic Reserve to be activated when market prices are close to the level that leaves users indifferent between paying or disconnecting themselves (Value of Lost Load). In other words, the policy is clearly intended to avoid disconnections and price spikes, hence it is equivalent to a price cap.

A similar issue applies to the Contract for Difference approach. Here the government pays an incentive to top-up the revenues of low-carbon generators when the reference price is 'too low' as compared to a benchmark. Given that the low-carbon technologies are so diverse, spanning from new nuclear plants to off-shore wind farms, the consultation has made clear that, in fact, different subsidy levels are needed for each type of technology. This obviously may create further effects, and possibly, distortions in technology adoption. In fact, by fixing a strike price, the central body in charge of administering the scheme will actually control the output volume by type of source. Thus there will be both an upper and a lower price centrally set, and quantity control of capacity. In turn, the Carbon Price Floor and the Electrical Power System (EPS), are the usual combination of environmental incentives and standards, and they will also alter market price equilibria, in order to further force the government's environmental objectives.

These four instruments (contracts for difference, capacity mechanism, carbon price floor and the EPS) may or may not work effectively, but their impact on the overall functioning on the electricity markets cannot be exaggerated. In fact, these markets are fragmented among a core segment under the control of a vertically re-integrated oligopoly, and an often illiquid set of other segments. Thus, if the British Government plans to cope with a considerable expected capacity gap in a decade, through central auctions for long term contracts targeted to capacity (set aside) and to low-carbon generation, it will become the most important player in the industry, with an effective control on output, investment, technological mix, and prices.

The existence of material market failures is fully acknowledged by the WP:

"These include: (a) reliability is a public good- consumers cannot buy reliability for themselves without providing it to everybody else… (b) there are barriers to entry in the wholesale market… and (c) prices in the electricity market may not send the correct signals to ensure optimal security of supply" (p.66).

The fact that under the proposed scheme the financing of new investments will not be provided by taxpayers (under public ownership), but by consumers through the cost of the subsidies within the bills they are going to pay (to private companies), is then more a distributive matter than a fundamental difference.[11]

The British EMR goes well beyond the paradigm of the 1990s. This departure from the previous creed has two relatively independent drivers. One is the bold position of the UK government about

[11] It seems that in any case the whole policy would need to be notified to the European Commission as it actually amounts to a form of state aid to private industry (including EDF, which is state-owned abroad).

de-carbonization of the economy, which was also at the core of the Stern Review of Climate Change (2006), on request of the New Labour government. However, the current Conservative-Liberal Coalition government, would have faced an investment gap in any case, simply because the privatized industry has eaten part of the capital of the plants of the divested electricity industry, and does not has the 'appetite' for replacing such fixed capital. At the same time, the industry has also eaten much of the country's endowment of natural gas, which only twenty years ago seemed to justify the end of economies of scale in generation.

The technological argument for privatization was in fact that the capital cost of a new gas plant (with combined cycle turbines) was limited, and linking prices and variable cost through competition was possible and efficient with a large number of players. In the words of the WP:

"gas-fired power stations are a mature technology with low and predictable capital expenditure. They are quick to build and their fuel costs, which are a large proportion of operating costs, are naturally hedged because the price of electricity moves in line with the price of gas, since gas (or sometimes coal), is typically the price setting (or marginal) plant. …Each of the low-carbon technologies the Government is considering differs materially from this standard of investment choice…typically has high construction (capital costs) and low operating cost… It is therefore difficult to make an investment case for them in a market where wholesale electricity prices are predominantly set by the short-run marginal costs" (DECC (2011), p. 28).

In other words, the low carbon technologies, such as nuclear or in an extreme way wind, solar and waves, are mostly based on fixed costs, with low or negligible marginal costs. When these features are combined with the empirical observation that major generation companies have preferred to vertically re-integrate with supply, not much is left of the original view that a competitive electricity market, with light independent regulation, would have solved the long term problems of secure supply, affordability and environmental sustainability in the UK.

The interplay between technological evolution, electricity demand and policy-driven changes in this context is analyzed, from different angles, by several essays in Jamasb and Pollitt (2011). Platchkov and Pollitt (2011) provides an overview of the longer run trends of increasing global electricity demand and explain the potential impact in the UK of electrification of transport, water and heating systems, now largely gas-supplied. Their main take is that demand will steadily increase and a possible coping mechanism will be to shift electricity demand through the use of demand-side management and smart grids and meters. On the potential of demand-side participation, Torriti et al. (2011) do provide evidence of possible price reductions but also warn against the constraints which may hamper the ability of consumers to manage electricity loads (thus limiting the potential price-reducing effects of demand-side participation). After presenting the technical aspects of demand side management and smart appliances for its integration, Jamasb and Pollitt (2011) focuses on the social dimension of the evolution of domestic electricity demand. The tension between policy targets such as carbon emission reduction and supply security, on the one hand, and affordability and fuel poverty on the other will exert opposite forces on prices. If higher prices are important for security and environmental concerns, these will be detrimental in terms of affordability, especially for disadvantaged citizens. Again, it seems difficult that relatively undisturbed market arrangements can solve the conundrum.

The social implications of the situation in the UK are a key issue of several essays included in Rutledge and Wright (2010). Gross and Heptonstall (2010) discuss technology adoption, the security and environmental protection is discussed by Keay, 2010 and fuel poverty by Boardman (2010). The book's overall aim is to analyze the unfolding of the UK's energy policy of the past thirty years and to provide a reflection on the lessons learned in the process. What emerges from the different contributions is that the effects of a highly ideologically-charged policy design has lead the UK to several problems in the energy sector, in particular with respect to security of supply and the dependence on gas imports, a lack of liquidity and transparency especially in the wholesale market, issues related to the ageing of infrastructure and lack of incentives for future investment, and an overall

> " 'portfolio power' over consumers rather than competition and effective choice" (Rutledge and Wright, 2010, p. 421).

The need of a 'new energy paradigm' is also advocated by Helm (2007), an edited book with several essays focusing on the long-term challenges and the inadequacy of the short-term perspective of the policy and the regulatory arrangements that emerged from some aspects of the reforms in the UK.

This recent literature, the Government's White Paper, the parliamentary debates, the responses of the stakeholders, all suggest that the British experiment should be reconsidered, and this reassessment can lead to a major paradigm shift, away from market fundamentalism of the last two decades. In the next section we reconsider some technological and environmental features of the industry, that may explain the reasons of this, somewhat surprising, U-turn of British electricity policy.

5. A reconsideration of some technological and environments features

Is there a lesson to be learned from this U-turn of British electricity policy? In order to provide a tentative (affirmative) answer to this question, some technological and environmental features of the electricity industry need to be restated. These features influence the design of policy reforms and stress the importance of a long-term planning perspective, with a more active role of governments.

Before the reforms of 1990s, vertically integrated monopolies were a response to the special features of electricity supply, such as the need to carefully standardize some technical parameters (voltage, frequency, and others), non-storability in the longer term, the physical laws requiring instant equation of supply and demand, and the need for a complex and integrated network which must be controlled by a system operator. The diffusion of generation from renewable sources, such as wind and solar photovoltaic, which are typically intermittent, not precisely predictable, unevenly distributed in space and non-storable, highlights the need for increasing the feasibility of storing electricity for longer periods of time efficiently, or managing the system by a mix of technologies. There are today several options of grid energy storage, which are however characterized by varying levels of efficiency. Traditionally, the most widely used technique is pumped-storage hydroelectricity, where energy is stored in the form of water, taking advantage of the height differences between bodies of water and is considered cost-effective and energy-efficient, with 70% to 85% of electricity used to pump water that can be regained[12]. It is estimated that the EU had, in 2008, 40.3 GW net capacity in this form, corresponding to almost 10% of total net electricity capacity. [13] This solution is however not available for many countries, and in any case covers only to a limited extent the possibility of storage.

The wave of reforms promoting competition in the UK electricity industry have perhaps overlooked this permanent systemic feature, that has important implications in terms of long-term management of investment. In the UK the availability of natural gas seemed to offer a new technology pattern in generation, based on relatively small-scale combined cycle turbines. The traditional issue of economies of scale leading to natural monopoly was considered less important than in the past, and competition in generation feasible and economical (Newbery, 2000). This argument of vanishing economies of scale focused only on some specific trends in technology adoption. With the benefit of hindsight, it is clear that the technological landscape is more complex.

[12] Electricity Storage Association's website, http://energystorage.org/tech/technologies_technologies_pumpedhydro.htm, retrieved online 17 February 2012

[13] Authors' elaboration on International Energy Statistics data, available at http://www.eia.gov/cfapps/ipdbproject/iedindex3.cfm?tid=2&pid=82&aid=7&cid=CG1,&syid=2004&eyid=2008&unit=MK, retrieved online 17 February 2012

To deal with non-storability, to manage a variable demand over the day and the year, and given the differences across countries of availability of hydro generation and fossil fuels, the use of multiple inputs and technologies (coal, natural gas, oil, nuclear power, geothermal, hydropower, solar, wind, biomass) is a structural feature of any regionally integrated market. At every point in time, production must exactly balance demand in an integrated multi-national market, making electricity a somewhat special commodity for trade. In fact, the lack of careful balance would disrupt the service. It is customary to describe the electricity industry as including four different segments: generation, transmission (the high voltage network), distribution (the middle[14] and low voltage network), and retail (supply to final consumers). These four activities have indeed different technological and economic characteristics. As mentioned, generation is often considered as potentially competitive. Transmission and distribution are natural monopolies, at the cross-border, national and regional level, because of the high network fixed sunk costs. Eventually, retail supply is also seen as potentially competitive, because trading and marketing activities do not necessarily imply high fixed costs. This conventional view of the industry, however, risks to miss its systemic nature, which makes it unique. To re-assess this issue, it is perhaps helpful to go back to some basic notions.

In spite of the wide variety of currently available energy sources, it should be acknowledged that most of these sources do not differ in the role they play in the fundamental electricity generation principles, established since Faraday and Maxwell laws. The available technologies do greatly differ however, as we shall discuss below, in terms of technical efficiency, capital and operative costs, costs passed to the network and the system, and externalities. The tension between this variability of generation techniques and the constant need to balance the system poses planning trade-offs which are, in turn, related to long-term investment decisions.

At any time, all switched-on generators of any technology and vintage, transformers, high voltage lines, substations and any switched-on electrical apparatus by the end user, form a closed circuit, where charges flow from negative to positive. In this perspective, the system is physically integrated at any time, whoever are the legal owners of segments of it and their contractual arrangements, and must be balanced, or it will burn out somewhere because of overload of its components. This makes the electricity supply industry unique from a technological perspective, and perhaps the best example of a network service. The important point here is that different generation processes and primary sources in fact play often a different role in an integrated system,

[14] The middle voltage network may sometimes locally belong to the transmission network

and “competition” at the generation level can take different forms, but is crucially linked to the overall functioning of the system, from provisioning of primary sources to users’ demand.

Given that, as mentioned, only a minor share of the electricity flows can be efficiently and cost-effectively stored, to balance demand and supply in a technical sense (not necessarily in an economic sense) one transmission system operator must be in charge of dispatching. This is the activity required to correctly switch on or off the generation plants, monitor the flows, the transmission grid, and other activities. Dispatching is managed in real time by control centres, where the system operator monitors tens or hundreds of control screens, which visualize the flows of hundreds of main transmission lines, including interconnections with foreign countries. No other industry, including for example the management of airlines, has such special pervasive central control mechanism. This fact has important consequences.

Under a vertically integrated electricity system, the control centre of the system generator, supported by a dedicated software, balances supply and demand by switching on the generators according to a ‘merit’ order, which implies knowing their incremental cost, and other functional aspects, of supplying electricity at that point in time from any specific point. When the owner of the control centre and the grid are the same, as for most or all the generators and distributors, the merit order should imply cost minimization in the short run for the vertically managed firm or organization. In principle, this process is not different under an unbundled electricity industry, but more complex in terms of information flows, transaction costs, and incentive mechanisms for investment. Under the reform paradigm of the last two decades, however, it was maintained that such costs would have been less than the benefits of competition, particularly in terms of cost minimization in the longer term, because of shedding excess labour and faster adoption of innovative technologies.

In fact, short-run competition is possible mostly in generation, and to a much more limited extent in retail sales. It is virtually impossible on the network itself, as duplicating transmission cables, transformers, substations, and other equipment would be costly and the balancing of the loads much more difficult. Competition downstream in turn is mainly related to differences across firms in commercial activities, advertising, billing and metering, etc. and it usually does not offer great margins to independent retailers if they actually need to compete.

As far as generation is concerned, the crucial issue, as mentioned, is the variability of production costs across firms and across technologies in the long run. The short-run pricing equilibria in the markets are only to a limited extent reflecting the marginal social cost of production. Looking at the costs from the limited perspective of the generator fails to capture social costs. This is our interpretation of the re-discovery by the British government that market prices in the UK have delivered wrong signals in terms of volume and quality of investment, and lead to under-investment and an energy mix which does not guarantee security of supply, de-carbonization, and price affordability.

As we have mentioned at the beginning of this section, the key efficiency issue in electricity supply based on fuels is not related to advancements in the fundamental principles and engineering (with the exception of nuclear generation, where investment and innovation in security is highly technology-specific) of the generation itself, but in the efficiency of converting different fuels into mechanical energy, then into electrical energy. This is an important point, as – in a sense – nuclear, coal, gas, oil, all do the same job of creating movement through steam[15] moving a turbine. Wind, hydro and in part Clean Coal Technology (CCT) gas use directly a fluid, but they perform the same conversion between different types of energy. The differences, however, in the capital and operative costs and features of the different sources are substantial. To those, several indirect and external costs should be added to gain a full picture.

In the rest of this section we briefly discuss three interrelated issues: direct costs of electricity generation by technology, environmental externalities i.e. additional social costs, and possible cost savings related to the demand side of the industry.

An indicator which is often used by practioners to compare unit generation costs is LEC (Levelized Energy Cost), which is defined as the price needed to break even when electricity is generated by a median plant using a given source of energy.

A simple formula is:

$$LEC = \frac{\sum_{t=1}^{n} \frac{(I_t + OM_t + F_t)}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

where t from 1 to n are years of operation, with n the year of decommissioning (usually up to 40 years) , I is yearly investment, OM yearly operation and maintenance costs, F are fuel costs, r is the

[15] In the combined cycle gas turbine (CCGT) the gas turbine is coupled with a steam turbine to generate additional electricity.

discount rate. It is difficult to compare these data across technology because of different assumptions, for example about incentives, taxes, boundaries of the object of assessment (for example system costs related to the connection to the network), discount rates, time horizons, whether base or peak load is considered, or an average.

Figure 4 gives some data for the US, based on EIA (2010) and other national sources and combines different recent surveys, originally expressed in different currencies for megawatthour, and in different countries, in a simple indicator, with the cost of coal generation, which as mentioned is still often the most important fuel, taken as 100. Just to give an indicative money value to this normalized indicator, according to EIA (2010), the LEC in the US, in 2009 for conventional coal was on average 94.8 USD per megawatthour, with a regional variation between 85.5-110.8 USD. The gas combined cycle levelized cost is one third lower than burning coal, while carbon capture and storage is around one third more costly than the traditional, highly polluting process. Wind on-shore costs according to one British study (Parsons Brinckerhoff, 2010) are similar to new nuclear , while off-shore wind generation and solar are more costly than nuclear[16]. Figure 4 also provides an indicative comparison of the amount of water used by each generating source and the average level of CO2 emissions, once again using coal as the base values (see below). As Table 4 shows, also the proportion between capital and operating costs is very different.[17]

[16] See also Risto and Aija (2008).
[17] On this issue, see estimated costs of different generating technologies in Politecnico di Milano-Dipartimento di Energia (2010)

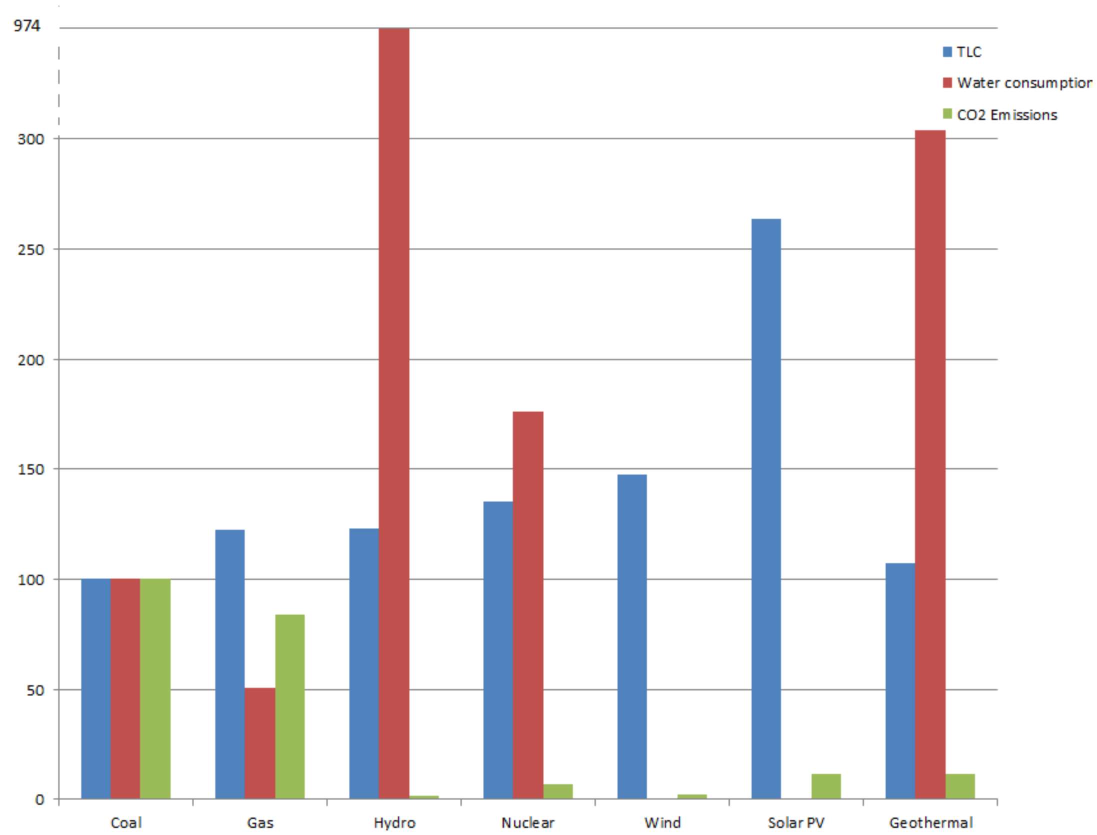


Figure 4: Total levelized costs (TLC), water consumption and CO2 emissions (base=100 coal)

Sources: Author's elaboration based on Energy Information Administration (2010); Parsons Brinckerhoff (2010); Graham(2006).

Plant Type	capacity factor (%)	U.S. Average levelized costs (2009$/megawatthour) for plants entering service in 2016				
		Levelized capital cost	fixed O&M	Variable O&M (including fuel)	Transmission Investment	Total system levelized Cost
Conventional coal	85	65,3	3,9	24,3	1,2	94,8
Advanced coal	85	74,6	7,9	25,7	1,2	109,4
Advanced coal with CCS	85	92,7	9,2	33,1	1,2	136,2
Natural gas-fired						

Conventional combined cycle	87	17,5	19	45,6	1,2	66,1
Advanced combined cycle	87	17,9	1,9	42,1	1,2	63,1
Advanced CC with CCS	87	34,6	3,9	49,6	1,2	89,3
Conventional combustion turbine	30	45,8	3,7	71,5	3,5	124,5
Advanced combustion turbine	30	31,6	5,5	62,9	3,5	103,5
Advanced nuclear	90	90,1	11,1	11,7	1	113,9
Wind	34	83,9	9,6	0	3,5	97
Wind-offshore	34	209,3	28,1	0	5,9	243,2
Solar PV*	25	194,6	12,1	0	4	210,7
Solar thermal	18	259,4	46,6	0	5,8	311,8
Geothermal	92	79,3	11,9	9,5	1	101,7
Biomass	83	55,3	13,7	42,3	1,3	112,5
Hydro	52	74,5	3,8	6,3	1,9	86,4

Table 4: Estimated Levelized Cost of New Generation Resources, 2016

Notes: * Costs are expressed in terms of net AC power available to the grid for the installed capacity

Source: Energy Information Administration (2010)

The variability surrounding these estimates is high. For example wind and sun conditions are site specific, but also the precise design and vintage of conventional thermal plants have a large impact on costs. Moreover there may be costs which are not accounted for in company accounts, or not fully, and greatly vary across sources. These are for example large differences in cost of disposal of waste, decommissioning costs, implicit costs of discontinuity of generation and insurance obligations.

Important examples of system costs related to non-carbon technologies are those for wind and nuclear generation. In the case of wind the load varies in an unpredictable way over time, even within an hour of operation. A grid that should accommodate this source of power should be able to respond very quickly to these changes, in order to avoid disequilibria in demand and supply. Thus wind will never be the election choice for base load. On the opposite site of the spectrum, nuclear plants are designed to work under a narrow range of generation flexibility, and cannot be easily used to face peak load. In fact, a grid will need to accommodate different sources and generation technologies according to different needs, and this poses difficult issues to be solved if the right mix is not available. For example, if emergency load is provided by diesel generators (as it happened in Italy during the exceptionally cold month of February 2012), the marginal cost of supply will be much higher than otherwise. Thus, which plants provide the reserve capacity needed to face peak load, or to exceptionally counteract a break in supply in some base load or medium load plants, is an important system cost factor. Another example of hidden costs of a generation source, is provided by the fact that some international conventions have exempted the nuclear operators from fully insuring themselves for third party liability, shifting the risk to taxpayers or third parties. The recent Fukushima accident suggests that the insurer of last resort is government, and that the cost per kWh of this shadow cost can be substantial.

Turning to the most important type of external costs, those related to environmental impacts, they can be classified according the type of natural resource involved.

a) As mentioned, most electricity generation plants are based on steam, including nuclear, coal, natural gas, geothermal, solar thermal. Usage of water is maximum with hydro, much lower with gas, biomass or coal, negligible with wind. Nuclear power plants use water mainly to cool down the condenser, and this is why, for example in Japan, the plants are located near the coast. See again Figure 4.

b) In terms of the emissions in the air of different pollutants, burning fossil fuels releases in the atmosphere huge quantities of CO2, perhaps in the range of 10 billion tons per year for electricity generation (see Figure 3). The impact on climate change is a key aspect of the current international debate. The Stern Review (2006) has been probably pivotal in precipitating the understanding of the large social costs involved in delaying the de-carbonization of the economy, and the UK seems to have taken seriously this concern, with wide implications for the electricity industry (see again Figure 4)[18]. Costs of CO2 could be internalized if capture and storage techniques became more widely used. A concrete example of Carbon Capture and Storage is Statoil's Sleipner Vest site in

[18] See also World Nuclear Association (2011).

Norway, while Vattenfall in Germany operates the first generating facility with CO2 capture (De Leo et al., 2009). It is however unclear that is would be the preferred option everywhere.

c) While all fossil fuels release CO2, other pollutants are found in different proportions according to the type of fuel. These include ozone, sulphur dioxide, nitrogen oxides, particulate, radioactive elements (which can be found in coal, for example), other toxic metals, such as, for example, mercury.

Only some of these environmental costs are internalized because of tradable emission permits and other schemes, and the interaction between technology adoption or dismissal and environmental policy is still critical for the electricity supply industry.

Eventually, the demand side will be in future an additional factor of technological change, with potential implications for the industry pattern. Chao (2011) reviews the impact of new standards in demand side management (DMS). These include changes in domestic electric appliances, ICT applied to optimize in real time demand and supply at the users' level, and perhaps most importantly, EU legislation and national directives on the energy performance of buildings. The new legislation sets that any new building, or any building facing major renovation, should be certified to meet certain energy standards. Substitution of traditional lamps with LED or OLED technology, heat pumps, small solar sources, co-generation of heat and electricity, etc., are only some examples of a more decentralized electricity system, which may lead to considerable savings, but also to obsolescence of part of the existing infrastructure.

Energy savings, sometimes labeled as Negawatts, i.e. negative power, is perhaps the next technological revolution, and it is unlikely that it will see the traditional utilities, which after all sell power, as the core drivers. In fact, most of the change is coming either from producers of appliances, or from governments' regulations. The possibility that electric cars will spread in the future adds to the complexity of the upcoming electricity scenario. See Jamasb and Pollitt (2011) for an interdisciplinary set of contributions on this issue. In turn, local microgeneration systems may have a considerable impact on the design and function of the network.

The actual fuel mix used to produce a country's stock of electricity may have important effects on several economic variable such as prices to final users and productivity of firms and on emissions and the environment. The following table provides the evolution of the fuel mix of electricity generation in EU-27 in the years 2008 to 2010 compared to the situation in the US in 2010.

Nuclear	27.7	27.8	26.5	19.6
Fossil fuel fired	55.2	52.5	52.1	68.7
Hydro	11.0	11.6	11.7	6.1
Other renewables	7.0	8.1	8.8	4.1
of which wind	3.7	4.3	4.6	n.a.
Other	0.1	0.1	0.9	0.6

Table 5: Fuel mix in the EU and USA-2008-2010 (%)

Source: Eurelectrics 2011 and Edison Electricity Institute data. Authors' elaboration

It can be noted that on average the share of renewables in the EU-27 is increasing, but that the fuel mix is still unbalanced towards fossil fuels, both in Europe and in the US. However, nuclear power and hydro are more important in Europe than in the US, especially in countries such as France or Italy, respectively. The following table summarizes the increase in the share of renewable sources between 1990 and 2008 in the EU-27 and considering Old Member States (EU-15) and New Member States. Renewable energy sources include wind power, solar power, hydroelectric power, tidal power, geothermal energy, solid biomass and biogas.

	1990	1995	2000	2005	2006	2007	2008
EU-27	11.9	13.0	13.6	13.6	14.2	15.1	16.4
EU-15	12.9	13.8	14.6	14.5	15.3	16.5	17.7
NMS	4.1	5.4	5.4	6.4	6.2	6.5	7.2

Table 6: Share of renewable energy(%)

Source: Eurostat. Authors' elaboration

The increasing attention to renewable sources as a replacement of fossil fuels is mainly related to environmental and security of supply considerations. Renewables may significantly help in reducing green-house emissions, a goal that is explicitly considered by the European Union (see for example the Directive 2009/28/EC of the European Parliament and Council which has set an explicit quantitative goal of 20% of energy consumption to be produced from renewables by 2020) and may reduce the dependency on energy imports which in turn may reduce risks related to price volatility and producing country political risk, causing potential energy interruptions (Neuhoff, 2007). The main renewable source in the EU, as of 2009, is hydroelectric power, which accounts for 57.6% of the total of renewables, followed by wind (21.3%), biomass (17.7%) and solar (2.4%), with the highest growth rates associated solar and wind (Observ'ER, 2010).

The increase in the share of renewable energy to total electricity consumption is particularly relevant in the newest EU members, with an average annual growth rate of 4.2%, compared to a 2.1% of the older member countries, but the absolute figure is still significantly lower (7.2% compared to 17%). The highest share of renewables in 2008 is in Austria and Sweden, with the highest growth rates in Hungary and Denmark.

Looking more in detail at the situation in selected EU countries, it is clear that geography and national strategies have shaped in the EU a very uneven landscape. The productive mix in the UK[19] in 2010 comprises roughly 76% fossil fuels (gas 47% and coal 28%, very modest role of oil) and the remaining part is provided by renewables (7%) and nuclear power (16%)[20]. This pattern can be compared with the situation in France[21]: in 2008 here approximately 76% of the electricity produced was generated by nuclear plants, only 10% from fossil fuels, and 12% from hydroelectric and 13% from all renewable sources. This situation leads possibly to much lower direct (short run) production costs in France than in the other EU 15 countries.

The Spanish productive mix is more balanced[22]. In 2008, there was a prevalence of fossil fuels (60%, most of it being gas) followed by solar (10%), hydroelectric (8%), with renewables in total accounting for 19%. The pattern in Italy is very different, where the current productive mix is the result of a political choice (following two referendums) of de-commissioning nuclear power stations. In 2008, 80% of the electricity is derived from fossil fuels, and 15% is of hydroelectric origin, while only 3.4% is from other renewable sources. Germany has a productive mix more similar to Spain, which includes 61% fossil fuels (mainly coal), 23% nuclear and the remaining 11% produced by hydroelectric and other renewable sources.

Turning to the Nordic countries, differences in their energy sources for electricity are also impressive. In 2010 the energy in Sweden[23] is produced mainly by hydropower (45.7%), nuclear

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[19] Following the revised Electricity Market Directive (2003/54/EC), electricity suppliers must provide information on the fuel mix necessary to produce electricity sold to consumers. Implementation dates vary across countries, but most information can be accessed at http://www.reliable-disclosure.org/ .

[20] DECC (2011).

[21] data source: IEA Statistics and Balances (http://www.iea.org/stats/).

[22] See previous note.

[23] data source: http://www.svenskenergi.se/upload/Om%20el/El%C3%A5ret/Filer/Electricity-Year-%202010.pdf, retrieved online January 20, 2012.

(38.3%) with only 13.5% coming from fossil fuels. In Finland, the largest source of electricity is the fossil fuels (48%) but a relevant part is derived also from nuclear (29%), with the remaining from hydro and other renewable sources. As regards Denmark, the productive mix is dominated by fossil fuels (71%, mainly coal) with the remaining electricity entirely derived from renewable sources different from hydroelectric. In recent years, Denmark has adopted a bold public policy in favour of wind generation which has led to the result of 20% of national electricity production from this energy source (Haney and Pollitt, 2010).

To sum-up, this brief overview suggests three important points to be considered in a reconsideration of the electricity reforms implemented in the UK and imitated elsewhere:

a) there was no European-wide technological shock that supported the reforms in the 1990s. The partial vanishing of economies of scale in generation happened for some technologies, but the basic technological principles of generation did not change in in the last twenty years. Economies of scale are still with us, when we focus not on individual plants, but on the physically integrated system

b) The systemic nature of the industry implies that only by looking at generation, transmission at supply at the same time the picture is complete. Different generation technologies and fuels co-exist, as they in fact have a very different cost/efficiency structure and perform often different and complementary roles, including reserve capacity. These roles can be accommodated given the variability of demand and supply over time, and non-storability, only to a limited extent by spot-market prices. In other words, short-run price equilibria are not compatible with the long-term investment horizon if we look at the system as a whole, even if we disregard social externalities

c) Eventually, the environmental impact of the different generation processes and of the demand patterns are quite variable, and there are important trade-offs between fixed costs, marginal costs, and external costs. It seems highly unlikely that a market mechanism, even a very sophisticated one, can fully internalise these costs, and the trade-offs implied by the overarching policy goals, without a public planning framework. This seems to be the lesson to be learnt from the British experience.

6. Conclusions and policy implications

This paper suggests that a reconsideration of EU electricity policy is needed. This policy, as embodied in several directives and national legislation, has been deeply inspired by the British experiment of privatization, unbundling, liberalization and regulation. The core of the reforms was to base the electricity supply on competition and market mechanisms, with light-hand regulation and no government role in long run energy planning and investment. Competition was deemed as possible at the generation level, because of declining economies of scale. Unbundling would have given different generators the opportunity to access the final supply market without foreclosures. And users would have had the benefit of switching to get the best deal for them. Regulation would just had the role of oversight of access to the network, and other minor roles.

The new UK policy framework suggests that this designed has failed to provide the right price signals to investors and users. The market, after more than twenty years of reforms, is illiquid, six major firms dominate it, and have vertically re-integrated downstream. Ownership of these firms is no more in British hands, which suggest that other operators had wider opportunities. Prices in the UK to the final users are not lower than in many other EU countries, including those which have been more reluctant to imitate the British model. Investment has been insufficient to replace the assets that were privatized, and the country faces a risk of electricity shortages in the next ten years.

Moreover, in terms of the long-term objectives of security of supply, social affordability, and de-carbonization, the British electricity industry needs important changes. Domestic natural gas reserves are declining, nuclear plants are old, and coal is still needed. The 'gas revolution' was far from sustainable in the long term, at least if considered in the perspective of self-sufficiency. The UK in future should either import gas, or electricity itself to a larger extent. In terms of social affordability, for a number of reasons, 'fuel poverty' is still widespread in the country, and it risks to increase. Eventually, the shift to de-carbonization is not supported by the current market arrangements.

We have not discussed in detail each of the measures proposed by the UK Energy Policy White Paper. One can think that some of them go in the right direction, but others may find them less than convincing (see on this House of Commons, 2011 and Rutledge and Wright, 2010) . We observe, however, that the UK, the country where the electricity market paradigm in the 1990s was invented, is going to adopt a national planning approach which is far from the previous fundamentally market-driven system. When a government directly buys infrastructure capacity, uses direct subsidies to support prices, poses quantity constraints on emissions, it goes quite far from a competitive model.

It is not clear to what extent the European Commission have noticed the change. The Third Package seems still based on the willingness to fully implement the reform paradigm of the 1990s. At the same time, however, the EU is insisting on environmental objectives, security of supply and also social affordability. The EU institutions should again look at Britain to understand some trade-offs arising when at the same time long-term policy goals are to be sustained and the markets are given excessive credit. After all, markets do not exist to support policies. The debate between the balance of energy planning and the market perspective is still open.

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