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PAST AND POTENTIAL ROLES OF ELECTRICITY SYSTEM OPERATORS: FROM LIBERALISATION TO CLIMATE CHANGE MANAGEMENT IN BRITAIN

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Jon Stern

Abstract

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The paper concludes with a discussion of the alternative views of the EU energy policy – the EU Commission has been proposing much increased interconnection to encourage multi-country regional markets, linking those markets into a Single European Electricity Market. Conversely, the UK, Germany and some other Member States have been promoting their national markets based on large-scale investment on national renewables with sizeable budgetary subsidies, supported by capacity payments. The role of the national electricity system operator is central to this debate with its functions very different in the two models.

Keywords : System operator, climate change policy, electricity liberalization, renewable generation, EU energy policy

JEL Classification : L94, K23, H76

Contact jon.stern.1@city.ac.uk
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Jon Stern (CCRP, City University, London)

ABSTRACT

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PAST AND POTENTIAL ROLES OF ELECTRICITY SYSTEM OPERATORS: FROM LIBERALISATION TO CLIMATE CHANGE MANAGEMENT IN BRITAIN

1 Introduction and Scope of Paper[1]

System operators (SOs) have been crucial for the development of liberalized, unbundled wholesale electricity markets both in the United States and in the European Union – and in many other countries around the world. However, over the last 5-10 years, SOs have been increasingly reconstituted to provide for the development and management of climate change policies. In the UK, that has involved them heavily in the procurement and operational arrangements for renewable generation and, to a lesser extent, of nuclear generation. Managing the intermittency of wind power has also had major implications for SO rules and operations involving transmission systems and the operation of wholesale markets.

During the 1980s and 1990s, and on to around 2008, OECD countries' electricity markets had been progressively liberalized with greatly increased competition in wholesale generation markets. In the US, the main model for this was the development of multi-State ISOs (independent system operators) of which the PJM system (Pennsylvania, New Jersey and Maryland) was the archetype. In England and Wales, Australia, and elsewhere ITSOs (independent transmission and system operators) dominated. These models were crucial in the spread of power sector liberalization and vertical unbundling within those countries and also in some middle income countries. Within the EU, ITSOs with fully ownership unbundled transmission networks were central to the EU Third Electricity Package of 2009 and currently a clear majority of West European EU member states now have electricity ITSOs.

However, in recent years, the policy emphasis has changed from liberalization per se to combining competition with decarbonisation to tackle climate change. The difference in emphasis is most obvious in the European Union. In 2007-08, the EU set out and agreed the "20-20-20" policy. This comprised a 20% reduction in EU greenhouse gas emissions from 1990 levels, an increase to 20% of EU energy produced from renewable resources and a 20% increase in EU energy efficiency - all to be achieved by 2020. Similar changes in emphasis have been introduced in the US (viz. California) and elsewhere but, in general, within looser policy frameworks than for the EU.

For Britain and other EU countries without large scale hydro generation resources, the EU renewables obligation implies a very large expansion in wind power with major implications for the viability of competitive generation markets. Large shares of non-carbon nuclear generation can also be difficult to reconcile with openly competitive generation markets. This creates major dilemmas and problems for competition in generation markets – and for SOs.

[1] I would like to acknowledge helpful discussions on the topics covered in this paper with Federico Boffa, Martin Cave, Guido Cervigni, Martin Lodge, Michael Pollitt and participants at the CCRP Research Workshop held in Milan in July 2013. Particular thanks go to Tim Tutton whose contribution has been invaluable. However, the views expressed in the paper are solely my responsibility. The paper is being published in Italian as '*Dalla liberalizzazione all'interventismo pubblico: la gestione dei cambiamenti climatici e il ruolo degli operatori di sistema*'.

These developments means that in several countries, competition *for* the generation market remains in place, but competition *in* the generation market is increasingly restricted. More importantly, to meet the "20-20-20" obligations, investment in generation in England and Wales and some other EU economies has become much more subject to directive planning than to light-touch indicative planning. This has led to electricity system operators becoming much more like delivery agencies for climate change and renewables policy targets rather than the co-ordinating entities for companies competing over a physical network in vertically unbundled markets as previously.

In this paper, we explore these issues and analyse in more detail the change in direction and the reasons for it. The focus is on the transformation of the SO in Britain and the implcations for other EU countries.

In the next section, we discuss types of system operator observed in infrastructure industries, including the origins of system operators in nineteenth century railways and their development in the late twentieth century electricity industry. We also discuss the economic underpinnings of SOs, particularly their role in the short, medium and long-term. Section 3 discusses the implications for the UK of the change to a climate change and renewables-driven policy agenda on SOs and the associated transmission and generation systems. Section 4 discusses these issues in the context of the EU and plans for the EU Single Electricity Market. The last section of the paper makes some concluding observations for UK and EU SOs and the electricity systems in which they operate.

2. Types of System Operator and their Historical Evolution

'Systems operation' and 'system operators' are terms which have only recently begun to feature in the debate about the regulation of network industries. The simplest definition of a system operator is that it controls access to the network by service providers and (possibly) extensions to it.

Note that this definition can readily apply within the context of:

(i) a single vertically integrated utility with multiple upstream sources and a single retailer distributing the product over a network across a wide geographic area;

(ii) a fully ownership unbundled network with competing upstream and/or downstream suppliers; and

(iii) intermediate models with (a) limited upstream and retail competition and with or without network unbundling.

The system operator is thus the key co-ordinating entity. This is set out in Keyworth and Yarrow as follows: [2]

[2] T Keyworth and G Yarrow, Economics of Regulation, Charging and Other Policy Instruments with Particular Reference to Farming, Food and the Agri-Environment, RPI, 2005, p. 29-30.

"Less familiar [than regulation] is the development whereby the distinct service activity of 'co-ordination', supplied to companies in the relevant sectors, has been identified and whereby responsibility for its provision has, subject to regulatory supervision, been allocated to a specific organisation or part of an organisation (a 'system operator')."

System operation functions were needed as the railways developed in the mid-nineteenth century. As soon as networks were integrated across regions, there was a need for:

(a) *Short-term Recovery Plans* (including diversions) - arising from points failures, accidents, etc;

(b) *Medium-term Network Access and Pricing Rules* – most obviously train timetabling; and

(c) *Long-term Network Investment and Expansion Plans* – within and between railway network areas.

Most nineteenth century railway companies operated as vertically integrated regional companies (as in UK, France and US) but some (e.g. Belgium) were state-owned. After 1945, most European railway companies were state-owned vertically integrated companies[3].

In electricity, power from various generators has to be physically delivered over a network to local supply entities and then to retail customers. Even for fully vertically integrated monopoly franchise electricity utilities, this creates similar co-ordination issues for electricity as in the rail example above e.g. over management of and access to transmission and distribution networks. However, one would not expect to see a separate SO entity within a vertically integrated power company. Rather one would expect to find one or more divisions or branches of the company undertaking the necessary co-ordination over the various SO functions.

This can be defined as an '*implicit*' SO arrangement. Its importance for the physical and engineering activities of the company is considerable, even if its effect on competition and market structure is by definition zero.

At the other extreme, as in many EU countries, we observe fully unbundled electricity systems with full ownership separation of the transmission network. In this model, SO arrangements are central in economic as well as administrative terms. Indeed, it is the SO arrangements and their integration with the network that is crucial for the effective operation of upstream and/or downstream markets. Here, we have '*explicit*' SOs.

2.1 Types of System Operator

[3] See Stern (2003) and its list of References for more on the economic issues around UK and other countries' railway development There has been renewed interest in railway SOs in the UK and the EU in recent years both at a theoretical level and to help achieve decentralised management within a wider market. See J. Stern, M.Cave and G. Cervigni *'The role of system operators in network industries'*, CERRE 2012.

Within vertically integrated utilities, we find *'implicit'* SOs, which have existed (without being necessarily recognized as such), ever since electricity companies emerged in the late 1890s. Typically the SO functions would be carried out by various different parts of the organization. For electricity, this was the norm until the 1980s when other forms of SO emerged.

When considering SO types, it is useful to distinguish between:

(i) Single-area networks/jurisdictions (and generation markets); and

(ii) Multi-area networks/jurisdictions (and generation markets).

Where there is upstream competition, the single area SO will co-ordinate the operation of the wholesale generation market <u>and</u> the TO (transmission operator) - including trade with neighbouring systems. However, in a multi-area context, there is more than one TO so that co-ordination with the wholesale market is more difficult, given transmission and other operational constraints.

The first set of electricity SO developments was primarily in a single area context in the US where a *functionally separate* SO was established in some US States to handle power purchases from IPPs under PURPA[4]. Functionally separate SOs established a single management entity (along with transmission operation and planning) which operated within a single vertically integrated utility. The functionally separate SO was not, however, a separate entity in terms of the *ownership* of any assets.

Functionally separate SOs were the first generation US SOs established in the 1990s. They were required to publish (regulated) "unbiased" network access terms and conditions and related services and operate an open, transparent and "unbiased" transmission planning system. Hence, Joskow suggests that they were intended to "operate and plan the transmission system <u>as if</u> there is no vertical integration"[5]. However, they completely failed to do that and, hence, have largely been replaced by other types of SO arrangement[6].

Note that the justification for the functionally separated SO was to eliminate discrimination by vertically integrated incumbent companies against competing generation from other companies. It was a failure in this; but it led to more thorough-going SO separation, at least in jurisdictions where liberalisation and competition were pursued.

The later SO models have been primarily of two types: (i) *'explicit' ISOs* (independent system operators); and (ii) *ITSOs* (independent transmission and system operators). The US is associated with multi-area/network ISOs (like PJM or the New England system)[7]. They are now known in the US as RTOs (regional transmission organizations) and have grown up since the late 1990s. Conversely, the UK – at least England and Wales - is associated with ITSOs, as is Australia and a number of other countries. Texas is an interesting case where there is an ISO in a single, isolated system and it operates much more like an ITSO than the other US ISOs.

4 The Public Utilities Regulatory Policy Act of 1978.
5 Joskow (2007) Slide 2.
6 See Section 3 of Stern (2011) and the discussion and references there.
7 Also California which is a large area with several interconnected transmission systems.

However, the ISO-ITSO distinction is now breaking down as ITSOs are unviable in multi-area/network jurisdictions. In consequence, whatever the relative merits of ISOs and ITSOs on paper, ISOs are increasingly becoming the norm. For instance, the England and Wales ITSO continues to operate but there is an integrated British generation market[8] which is operated by an ISO. This GB ISO co-ordinates the generation market with (a) the England and Wales TO (which is a separate business within the E&W ITSO) and (b) the two Scottish TOs.

It is also possible fully to unbundle ITSOs into SOs and TOs. That was considered but rejected by Ofgem (the British electricity and natural gas regulator) in its RPI-X@20 review of energy network regulation. However, the England and Wales ITSO does operates with a limited degree of business separation for the SO via price cap incentives[9]. One important issue with ISOs and all non-TO linked SOs (especially fully separated SOs) is that they are very asset-light so that it is not possible to apply financial incentives to them which put significant revenues at risk[10].

There are two other types of SO that have been developed in the EU context. The 2nd EU Directives on Electricity and Gas of 1996 required, as a minimum, functionally separated transmission (and distribution) networks with designated system operators. As in the US, the functionally separated SOs failed to support competitive markets as very clearly demonstrated in the EU Energy Inquiry of 2006-07. In consequence, the 3rd Package of 2009 introduced *ITOs* (independent transmission organizations) as a replacement for functionally separated SOs and as an alternative to ITSOs. (An ITO is an ITSO that is owned by and remains inside the power company, but it has to operate with a high degree of separation (legal separation) relative to the rest of the utility[11]).

ITOs have been proposed as a way of avoiding the problems of vertical integration in upstream and downstream markets but without losing economies of scope and scale (including for investment financing). The French and German Governments lobbied hard for ITOs to be allowed as options in the 3rd Energy Package of 2009, although Germany now seems to be moving quite rapidly towards ITSOs in both electricity and gas. This leaves France as the sole large West European electricity system not operating primarily as an ITSO.

ITOs, like ITSOs, are single area/network constructs. However, the EU is developing an alternative to the ISO in the multi-area context. This is the *'virtual' ISO*. 'Virtual' ISOs are becoming the dominant model in the EU, particularly for multi-area markets. They are national power markets which are linked together by network codes rather than by an explicit ISO or similar.

Consider the Nordic electricity market, which has become the key model for inter-country EU integration. There is a Nordic electricity trading market (Nordel) which now covers Denmark, Norway, Sweden, Finland, Estonia and Lithuania . In addition, each Nordic member state has

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8 Which includes Scotland but excludes Northern Ireland

9 There are some specific SO incentives the costs of carrying out SO functions. These are set up as separate price cap incentives which are separate from the TO incentives in the TO price cap. See Ofgem RIIO-T1 publications 2011-12.

10 See Pollitt (2011) for more on this

11 Leveque et al (2008) call it an LTSO – Legally unbundled Transmission System Operator

its own national ITSO which is regulated by its own national regulator. These national transmission systems are physically linked by interconnectors. The co-ordination of interconnector access and access to national grids is handled by Grid Codes and inter-transmission company co-operation under the Nord Pool co-operation arrangements and not by an explicit SO.

One important feature of the 'virtual' SO model is that it operates without an electricity regulator for that market. There has been movement towards an EU-wide electricity and gas regulator (ACER)[12] but, as yet, it has very few powers. In the US, the FERC[13] has some regulatory powers over RTOs, whereas there is as yet no comparable body in the EU.

As regards the regulation of transmission investment in the US, State Regulatory Commissions are the main regulatory agency involved. Conflicts between them, RTOs and the FERC can cause major problems – particularly over approvals of interconnector investment. Implementing ISO investment proposals can be a major weakness with multi-area ISOs, but the problems are also likely to be serious in cross-country 'virtual' SOs – probably rather more so[14].

The problems over incentives for transmission investment do not arise with ITSOs where the financing of new investment and the regulatory oversight are united, but ITSOs covering more than one country would require TO mergers across area. For both economic and political reasons, these are very difficult to achieve and hence virtually unknown.

However, ensuring sufficient interconnector investment can be a serious problem. There have been suggestions for 'explicit' rather than 'virtual' ISOs in the EU specifically to internalize the externalities for wholesale market depth from more interconnection. However, given US experience with RTOs, that would probably also require EU regulatory (and subsidy) alignment as well. As discussed in Section 4, how to increase interconnection has in recent years become a major issue in the development of the EU Single Electricity market.

Note than the US ISOs are all non-profit making. ITSOs in general are not and 'virtual' ISOs are groupings of profit making (or at least commercialized) companies. Whether or not SOs are commercialized significantly affects what incentives can be imposed on them – and their likely responses[15].

2.2 Electricity System Operator Functions

The development of SOs in the US and EU after 1990 was intimately related to the competition issues arising from the problems of achieving effective competition in generation markets across networks. At least initially, these networks were owned and operated by the incumbent utilities who owned much of the generation. Hence, the modern discussion of SOs starts with their role and development in US electricity as upstream generation competition was introduced into a world of vertically integrated utilities[16].

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12 Agency for the Co-operation of Energy Regulators

13 Federal Energy Regulatory Commission

14 See Pollitt (2011), Stern (2011) and CERRE 2012 for a fuller discussion of these issues.

15 See Pollitt (2011) for further discussion of this issue.

16 During the 1970s and after, the US gas industry created a set of fully unbundled interstate high pressure gas transportation companies as ITSOs. They (unlike the

The US electricity SOs were primarily devised to try to prevent the discrimination by these vertically integrated companies against outsider generation. This process was accompanied by the evolution during the 1990s of the 'tight pools' of the Eastern US into integrated multi-State wholesale generation markets. Successive reforms to the resulting wholesale electricity markets has led to the development of RTOs with progressively more autonomy[17].

The starting point for a competition perspective is that *some ownership structures give the former monopolist the means and the motive to distort competition and to foreclose entry into the competitive service provision segments of the network industry value chain*. This has attracted competition authorities to the notion that <u>either</u> (a) the motive should be removed by full ownership separation <u>or</u> (b) that the means to distort competition should be removed by separation, better regulatory enforcement - or by the insertion of an independent SO. (Note that the creation of a separate SO – particularly ITSOs - is typically a major part of a separation approach.)

These competition problems include:

(i) *Short-term issues* – these primarily relate to the organization of generation schedules, the management of transmission constraints and the interaction of both with generation (and transmission) markets.

The role of the SO here is primarily on setting rules within which the TO operates. (This is clearest in the Nordel system to which the table refers. In the UK and other electricity systems, the SO has some substantive responsibilities for dispatch/supply, demand balancing and other operational decisions on network use as well as for rule setting.)

(ii) *Medium-term issues* – these primarily relate to transmission network access and pricing and are at the core of SO operations, particularly for linked jurisdictions and/or generation markets in liberalised electricity systems.

PJM is the classic model, with Nordel (and now CWE) as 'virtual' EU equivalents.

(iii) *Long-term issues* – these primarily relate to transmission network investment, including interconnectors. This is the area where ISOs differ fundamentally from ITSOs as the former can only *plan* new transmission investment, whereas ITSOs can, subject to regulatory oversight, both *plan and implement* new investment.

electricity ISOs) have a single regulator – FERC. The US gas history is thus very different – and much more successful in competition policy and other terms than the equivalent gas history. See Joskow (2009) and Stern (2011).

17 The most obvious examples are Texas and the PJM RTO. See CERRE Report (2012), Stern (2011) and Pollitt (2011).

NordREG (2006)[18] provides a useful, simple summary of short, medium and long-term SO functions for liberalized electricity markets without major climate change policy intrusions. This is set out below.

Table [1] System Operator Functions by Time Period

Time Period	**Function**
Short-Term	Secure short-term (1 hour or less) system operation according to operational agreements and codes
	Maintain demand supply balance within short-term (1 hour)
	Manage disturbances and emergencies by system planning procedures and methods
	Manage shortage situations by agreed action plans including disconnections or equivalent
Medium-Term	Adopt and implement consistent and co-ordinated capacity calculation and allocation procedures as the basis for day-ahead, weekly and monthly system operation
	Adopt and implement common and consistent procedures for congestion management
	Operational planning for network operation for up to 1 year ahead, including maintenance planning and co-ordination
	(Settlement) Set imbalance prices, settlement principles and execute national balance settlement
Long-Term	Define common technical requirements for secure system operation and expansion

Source : NordREG 2006, p. 6-7

The equivalent TO functions are set out below. Note that some of these are allocated to the SO in other jurisdictions. These are marked with an asterisk.

Table [2] Transmission Operator Functions by Time Period

Time Period	**Function**
Medium-Term	Ensure the technical compatibility within and between networks
	Maintain the proper functioning of the transmission system by

[18] NordREG (2006), *A common Definition of the System Operators' Core Activities*

	appropriate planning methods and tools
Long-Term	Plan the expansion of the network, including interconnection *
	Carry out network expansion (new investment) in a timely manner

Source: NordREG 2006, p. 6

As we will discuss in more detail below, it is on long-term issues that the post-2008 climate change perspective has most affected SOs, so that in the UK and elsewhere, SOs have increasingly become agents for procuring generation of specified, different types – particularly types of renewables. There are also implications for short and medium-term factors e.g. from handling must-run or intermittent generation; as we shall see, the latter is more important, particularly for wind power.

2.3. SO Economic Design to Meet Functional Requirements

SOs arise in electricity and other network industries to provide co-ordination. There is a need in network industries for an explicit co-ordination function, which differs both from regulation and from the operation of the network. This is needed to cope with the significant pecuniary and non-pecuniary externalities which link the now increasingly separated functions of running the network, providing services over it, and protecting end users.

There are three key co-ordination functions which, in the liberalized and unbundled framework, require different economic approaches. By time period, these are:

(i) *Short-term traffic management*

With power flows coming from all directions, if congestion is to be avoided, there is a short-term traffic management problem. There are also important issues of system recovery, transmission constraint management plus short-term interactions with upstream and downstream markets, including contract fulfilment/compensation.
As discussed in Cave and Stern (2012), these could conceivably be handled within a market framework. However, both in theory and practice, the dominant approach (derived from Transaction Cost Economics) is a non-market hierarchical one based on an authority-endowed interface co-ordinator - or SO. This approach dominates as it is well-suited to handling issues of (a) asset specificity and (b) incomplete contracts. Both of these are important in electricity, with the latter particularly important for short-run flow management and market co-ordination. In addition, where some degree of vertical integration remains, a system operator can help prevent discriminatory opportunistic behaviour. Finally, the SO can provide trust in contract execution (e.g. reliability and fair dealing).

(ii) *Medium-term network access allocation*

For the medium-term issues around access allocation and pricing, competition policy analysis is the most useful conceptual framework.
The allocation of network access 1-7 days, 1-4 weeks and up to 12 or more months ahead has three dimensions of major consequence for the industry as a whole[19]:

[19] It could be longer than 12 months ahead but is shorter than the relevant period for investment planning.

(a) how best to allocate available network capacity among service providers, including allowance for planned maintenance;
(b) how to ensure that network revenues cover costs[20], particularly when the network itself is investor-owned and self-supporting; and
(c) how to do the above without distorting competition among or between service providers.

The fundamental issue is that "vertical integration between transmission and generation that creates the incentive and opportunity for exclusionary behaviour."[21] Having a separated SO (ISO or ITSO) to implement the access regime helps solve these problems, particularly when accompanied by sufficiently effective separation between TO and generation - and effective regulatory oversight

(iii) *Long-run investment and network expansion*

In a liberalised electricity industry, decisions about the expansion/contraction of network capacity have to be made in a way which benefits end users and which does not distort competition among or between upstream or downstream service providers. These decisions are typically regulated by a specified (independent) regulatory agency. SOs can be seen as an attempt to answer these problems. This is most obvious with ITSOs but it applies in different ways to ISOs - explicit and virtual.

How can an investment plan for a network be determined? Doing so involves 'integrating' the projected demand of all network users. That can be done by addressing end users. But where the *location* of transmission demand is relevant (as is typically the case), it may be necessary to go to the suppliers. This creates an 'adding up' problem: the sum of the projections of individual suppliers' may not match the overall demand, creating the risk of over-or under-development of the network. An SO, separated from any provider can undertake this investment planning task.

As set out in Cave and Stern[22], indicative planning provides a useful intellectual framework. How might a co-ordinated investment plan be generated? Basically, by two methods: (a) the analytic and (b) the synthetic.

In the former, the planner forecasts electricity demand, derives where it should be produced and checks the results with the firms involved. This iterative process manages expectations and is intended to generate a consistent plan – a 'top-down' approach. The 'bottom-up' synthetic route starts from suppliers' expectations or projections. The planner tests these for consistency in the 'adding up 'sense and reports back. Again an iterative process ensues, which is intended to lead to a commonly held, published prognosis of the future.

These methods are reflected in the investment planning of electricity transmission networks. For instance, in the UK, National Grid (from 2002-2011) published annually a 7-year ahead statement of generation proposals in England and Wales plus transmission investment proposals etc. The generation proposals were <u>not</u> forecasts but were generation and transmission investment (and scrapping) proposals that were currently known to National Grid and against which it could plan its transmission investment – but which National Grid expected to be revised. The projections in the 7-Year Statement were also compared to likely demand and were annually updated by National Grid.

[20] Including explicit or implicit subsidies where relevant.
[21] Joskow, P. (2008). 'Lessons learned from electricity market liberalisation.' *The Energy Journal*, 29(2), p. 22.
[22] See Cave and Stern (op cit) Section 4.3.

The resulting process was a classic indicative planning approach as applied to an infrastructure industry with a core central (monopoly) physical network which was expanded only by high cost, long lead-time investment[23]. Similar arrangements exist in other, if less formalised.

This area is the one where climate change policy issues have most impacted on SOs and their role. The requirement to introduce large amounts of renewable generation means that the light-handed indicative planning approach to investment has come under great pressure with the result that transmission amounts and location have to be jointly planned and implemented in a much more directive manner.

This particularly applies to wind power. Firstly, wind power can only be efficiently installed in particular locations – where the wind blows most often. These locations are typically a very long way from major population centres implying considerably higher transmission investment requirements. Secondly, the intermittency of wind and the need for back-up thermal generation (e.g. gas) again requires significant supporting transmission investment. These issues and their implications will be discussed at length in Sections 3 and 4 below.

3. Electricity SOs post-2008: Climate Change and Energy Security – the Case of the UK

The previous sections describe a period in the evolution of, in particular, the electricity supply industries in (and within) a number of OECD countries. This was dominated by the linked themes of coordination across jurisdictions, unbundling, liberalisation, encouraging commercially-based sector investment and increasing competition.

This process dominated electricity and energy policy in the UK and the EU from around 1990 to 2008 and the UK (or at least England and Wales) was very much a leader in these developments. As discussed above, it implied the use of system operators as network access managers and generation investment co-ordinators, but both the volume and the technological choice of generation investment were left to competing, (mainly) privately owned companies.

These co-ordinator SOs were, as discussed above, sometimes part of ITSOs (as in England and Wales), sometimes independent (as in the US) and sometimes semi-separated parts of electricity utilities (as in France and Germany). Within the US and to a lesser extent in the EU, we also saw the development of multi-state/jurisdiction electricity markets and associated SO arrangements. However, within the EU, the ITSO model, in which Britain was a lead developer has been increasingly followed by other EU countries, including Italy and Spain.

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23 See http://www.nationalgrid.com/uk/Electricity/SYS/current/ for the last National Grid 7 Year Statement. National Grid were proposing for 2012 to replace the 7 Year Statement with a 10 Year Statement; but, instead of that, Ofgem published a much shorter and less detailed Electricity Capacity Statement as advice to the Secretary of State for Energy. See http://www.ofgem.gov.uk/Markets/WhlMkts/monitoring-energy-security/elec-capacity-assessment/Documents1/Electricity%20Capacity%20Assessment%202012.pdf. This reflects the changes in the UK electricity market from a decentralized market model for wholesale generation to a much less decentralized model. Generation planning in England and Wales has since 2008 become more directive rather than simply indicative.

From 2005, with the rise of climate change concerns in general and the growing emphasis on renewable generation, the policy perspective changed sharply. In particular, the emergence of binding EU renewable targets after 2008 meant that there was a need for new generation to be much more technologically related to EU climate change objectives.

As regards SOs, in the UK this led to an emphasis on directive planning and the SO as a delivery agency for technology-specific generation. Hence, the government has created a new body, the Great Britain System Operator (GBSO), National Grid. Broadly, National Grid has, in its SO role, been designated as the 'delivery agent' for the Energy Market Reform (EMR), including the delivery of the renewable generation targets. Hence, while Britain led the development of 'co-ordinator' ITSOs in the 1990-2010 period; since 2010, it has been a pioneer in the development of planning-based directive SOs.

As will be set out below, it has been the large-scale introduction of intermittent renewable generation technologies, particularly wind and solar power that has been the crucial factor determining the shift in the role of the SO in Britain. Taking action to reduce carbon emissions is not the same as – and does not necessarily require – extensive investment in renewable generation either in theory or in practice. But, the 2008 EU renewables targets not just brought together carbon reduction targets and large-scale investment in intermittent renewables but positively elided the two issues. However, the issues are not the same; it is not obvious that heavy investment in renewable generation is an efficient way of addressing climate change and indeed, as discussed below, there much is considerable evidence that it is not.

It is the decision process outlined above which, at least in the UK, has driven electricity developments in general. In particular, it has led to the market co-ordinating SO becoming a planning and implementation body by which to achieve EU and UK government electricity generation technology targets. As yet, other EU Member States have not gone far down this route and, given patterns of renewable resources they may not need to do so. However, the British example well illustrates the pressures on SO arrangements arising from costly, low density, renewable generation targets.

3.1 UK Electricity Policy and SO Policy - From Co-ordination to Direction

The 1990-2008 pro-competitive, unbundling transformation was pursued in the UK electricity and in many other EU and OECD countries in spite of there being a powerful logic for vertical integration. The vertical integration logic includes:

(a) the potential *economic* benefits of being able to internalise within one decision making body what would otherwise be sometimes problematic externalities; and

(b) the *political* attraction of making it easier for governments to control what has always been a politically sensitive industry and one which governments have often wanted to serve objectives broader than providing a reasonable level of security of supply at least cost.

The reasons why governments were prepared to opt (to varying degrees) for unbundling, liberalisation and the rest were various, but included:

- a search for efficiencies which could be realised by coordinating generation over wider geographic areas that those covered by the existing vertically integrated entities;

- increased realisation across the utility sector that, whatever the potential benefits of vertically integrated monopoly, these could come at a high cost in terms of the X-inefficiency (and customer unresponsiveness) associated with state ownership, particularly when associated with monopoly;

- a desire to stimulate private sector investment, especially in generation;

- relatively low primary oil and gas prices from the mid 1980s to the early 2000s – which lowered the political profile of energy generally and reduced the political impulse to have control of the industry.

However, since at least the early 2000s, the political agenda for energy, and especially for electricity, has moved on.

- *Oil and gas prices have risen substantially*, raising the political profile of energy and increasing the need for government to be seen to be doing something about them – and something rather more direct than facilitating competition.
  (In contrast with oil prices over the last few years at over $100 per barrel, the inflation-adjusted average price of oil between the mid 1980s and the early 2000s was generally under $25 per barrel.)

- *Climate change worries* that have led to some governments (notably in Europe) wanting to reduce carbon emissions in the energy sector (particularly in electricity) and to increase the amount of generation from renewable sources. These impulses have been embodied in, for example, the EU Renewables Directive and the UK Climate Change Act.

- *Climate change initiatives have exacerbated electricity security of supply concerns*, not least through requiring the closure of substantial amounts of fossil generating plant and through not being able to rely at times of system stress on (the increasing proportion of) generation from intermittent varieties of renewable generation, like wind and solar.

The net result of these changes has been that, EU governments have had to find ways of meeting volume targets for *both* decarbonisation *and* renewable electricity generation. They also have to cope, firstly, with the security of supply implications of increased penetration of renewable generation (e.g. on transmission and interlinked markets): and, secondly, deal with the cost consequences of all of this at a time of unusually high retail energy prices and all the political pressures which those entail. Those pressures, not least with respect to operating a secure electricity system, are significantly more intense for those countries - including the UK - which do not have substantial amounts of hydroelectric generation (which combines its renewable and low-carbon status with a high degree of reliability at times of system stress).

3.1.1 The Restructuring of the British Electricity SO after 2008

The questions above have affected other EU countries as will be discussed below. However in what follows in this section, we concentrate on the UK example.

The UK was the electricity liberalization pathfinder in Europe but now seems to be spearheading the movement back to a much more planned electricity sector, with an SO as the key agency for commissioning generation. This has occurred since 2008 as a direct result of the EU 20-20-20 obligations of 2008 and, in particular, of the 20% renewable energy target.

The EU Renewables Directive requires 15% of total UK energy consumption to come from renewable sources by 2020. Because of the perceived difficulty of decarbonisation in other sectors, this is usually taken as requiring at least 30% of electricity generation to be from renewable sources to meet that target. In 2011, only 9.4% of UK electricity generation was from renewable sources[24].

In the UK context, meeting these renewable electricity generation targets primarily requires the building of large numbers of wind turbines. On-shore wind power was the original focus for achieving the renewable targets. However, in view of the growing problems of finding sites – and obtaining planning permission – for on-shore wind, the focus has shifted increasingly to significantly more expensive off-shore wind turbines.

TEXT BOX

UK RENEWABLE GENERATION CAPACITY 1980-2012

Wind generation did not exist in the UK until after 1988. From the 1960s, there had been around 1,500 MW of installed hydro (mainly in Scotland) and this was the only source of renewable electricity. However, by 2008, installed renewable generation capacity had increased to 6,800 MW. Most of the increase (2,800 MW) was in onshore wind, with accompanying increases of 900 MW for landfill gas and 350 MW for energy from waste. In 2008, offshore wind contributed almost 600 MW.

By 2012, total installed renewable capacity was 15,500 MW – an increase of 128% over 2008. Installed onshore wind capacity had doubled to 5,900 MW and offshore wind capacity had increased sharply to 3,000 MW. The other major increases were in (heavily subsidized) solar capacity from 23 MW in 2008 to 1,700 MW by 2012 and in plant biomass generation from 200 MW in 2008 to 1,200 MW in 2012.

[24] Department of Energy and Climate Change, 'Digest of United Kingdom Energy Statistics 2012'

In the year to end-September 2013, onshore wind capacity increased by 25% and offshore wind capacity by 36%. However, the increases in generated power were much less – around 7.5% in each case. There were again bigger increases in solar capacity and in biomass generation with plant biomass generation more than doubling over the 12 months to September 2013.

Sources: *Digest of UK Energy Statistics (DUKES) 2012 and 2008 and Energy Trends December 2013*

If the relevant issue was just about increasing the penetration of low-carbon generation, then there are various technology-neutral policy options in place or available to governments. These include:

- *tradeable carbon permits*, as with the EU Emissions Trading Scheme (EUETS);

- *carbon taxation*, as with the UK Carbon Floor Price/Climate Change Levy;

- *low-carbon volume obligations on energy suppliers*, as with the UK's Renewables Obligation which requires electricity suppliers to either purchase a given percentage of their electricity from renewable sources or pay a buyout price.

All of these options have their advantages and disadvantages but all of them have the characteristic of working with the grain of energy markets – leaving it to electricity suppliers, generators and consumers to make decisions about the most efficient way of complying with the regime requirements[25].

Even if a government wants to provide some degree of technology guidance, it can do that in a relatively market friendly way e.g. by subsidy auctions or similar. Auctions have many potential problems (e.g. achieving a sufficient number of serious bidders), but they have proved valuable and robust in other contexts (e.g. over radio spectrum allocation. The use of subsidies for allocating subsidy support for British renewable generation has been suggested by the UK government as an objective in coming years. However, as yet, there is little information about how what would be covered (single renewable technologies or, alternatively groups of technologies), or about the method of auction, the length of contracts or by when this might be achieved. It appears that onshore wind and solar power are the lead candidates with initial auctions proposed by 2018-19[26]. A key issue is what role administrative decisions will have relative to auctions; there is potential for government 'guidance' at all stages.

[25] Note, however, that the UK Renewables Obligation skews the choice between renewable technologies through its issuing of Renewable Obligation Certificates (allocating more certificates per MWh to favoured higher cost technologies).

[26] See http://www.telegraph.co.uk/earth/energy/renewableenergy/10517240/Green-energy-cost-cutting-plans-may-lead-to-more-onshore-wind-farms.html For a more general discussion of renewable subsidy auctions, see Policy Exchange Report , 'Going, Going, Gone', December 2013.

However, problems arise if a government is not content with simply setting a high level decarbonisation/renewable energy target and with leaving the energy market to resolve other issues (security of supply, choice of low-carbon technologies, cost to consumers). This is true for many countries but seems particularly noticeable in the UK because of the sharpness of the break between its past commitment to liberalised energy markets and the extent to which it is now planning substantial government intervention in those markets.

The background to this transition includes (a) the prospective retirement of almost all of the UK's existing nuclear generation fleet by 2025[27]; (b) the relative lack of hydro generation capability (particularly in England); and (c) the difficulty (because of political opposition) of building onshore wind generation. These factors have at least two important consequences:

- a heavy British reliance on relatively expensive offshore wind generation to meet statutory targets for renewable generation; and

- the issues posed by securely operating a relatively isolated national energy system with a high penetration of intermittent (onshore and offshore) wind generation.

These factors have increased worries over the security of energy supply, particularly given political as well as economic worries over gas supplies and prices.

TEXT BOX

UK ELECTRICITY INTERCONNECTION WITH NEIGHBOURING COUNTRIES

GB (i.e. the UK excluding Northern Ireland) currently has only 4GW of interconnector capacity, against maximum demand on the transmission system over the last few years in the range of 56-60GW. The UK, therefore, does not have the ability afforded to some mainland European countries of being able to ride through fluctuations in wind generation through importing or exporting large proportions of national maximum demand through interconnectors with other countries.

New interconnections are being built (e.g. with Ireland), but GB remains a relatively isolated system. This is important given the developing EU Commission policy of encouraging market coupling via interconnections on the lines of Nord Pool and the Project Target model.

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[27] See World Nuclear Association overview of UK, February 2014. The 2025 date allows for past life extensions of the UK AGRs. It is possible, if unlikely, that they will be given further life extensions.

The intermittency problem is crucial for the problems of maintaining competition in (rather than for) generation. Most obviously it means that much mid-merit or even base-load thermal generation (gas and coal) also becomes used only intermittently and relatively unpredictably. Hence, special arrangements need to be made to keep thermal plant on the system let alone obtain continued investment[28]. As Helm rightly claims, once intermittent renewables are supported by fixed price contracts, *all* new generation investment effectively has to be supported through fixed price contracts, particularly new natural gas generation[29].

These issues explain, at least in part, why the UK government is keen to build new nuclear generation – it is expected to be cheaper than at least offshore wind generation and it provides generation which is not reliant on the wind blowing (or the sun shining) – and thus contributes to security of supply in a way that intermittent generation does not.

[28] There are also serious implications for transmission design and operation but these are beyond the scope of this paper. See

[29] See Toxic Prices D Helm (2014)

TEXT BOX

Relative Costs of Nuclear Power and Offshore Wind Generation

The most frequently cited estimates of generation costs in the UK are the estimates of levelised costs (plant lifetime costs, discounted over expected plant lives and divided by discounted MWh) made by Mott Macdonald for the UK government: 'UK Electricity Generation Costs Update', June 2012. Mott Macdonald made their estimates on two bases – 'FOAK' (first of a kind) and 'NOAK' (nth of a kind) to try to reflect both (then) current reality and the prospects for costs reducing through time. Their results had nuclear costs falling from just under £100/MWh to around £68/MWh 'possibly for projects initiated as early as 2017', onshore wind at a then current £94/MWh with 'a modest real cost reduction over the next decade', and offshore wind falling from around £157-186/MWh to around £100-125/MWh by 2025.

In December 2013, the UK Government announced the strike prices for various renewable technologies. For offshore wind, the announced strike price was £155/MWh falling to £140/MWh after 2017, while for onshore wind it is £95/MWh falling to £90/MWh after 2017. These strike prices can be compared to the (heavily criticized) 35-year contract price for the Hinkley Pont C nuclear station of £92.5/ MWh. Among renewable technologies, only landfill gas, sewage gas and waste energy with CHP had lower strike prices than the nuclear contract price.

(See '*Investing in renewable technologies – CfD contract terms and strike prices*', DECC, December 2013.)

However, as has been pointed out many times, nuclear generation is one of the least market-friendly forms of generation. Reasons for this include not only its high proportion of fixed costs (a characteristic shared with many other low-carbon technologies) but also the acute variability of construction costs plus long (and variable) construction times. Other things being equal, liberalised and reasonably competitive electricity markets prefer low capital intensity, reasonably certain construction costs and short construction times – hence the rapid growth in CCGT gas generation in the UK and elsewhere 1990-2005.

In the light of these and other considerations, the UK government has decided that simply 'nudging' the market (through carbon taxes, carbon trading, renewable energy obligations on suppliers etc) will not be enough to deliver its 2020 objectives. In particular, these relatively market friendly policy instruments will not be enough to deliver new nuclear generation. At the same time, a policy instrument designed specifically to subsidise nuclear power alone would fall foul of EU State Aid provisions, as well as potentially posing other political problems.

The UK government has therefore decided to pursue an altogether more interventionist approach to deciding both how much generation capacity there will be and what types of power station will be built. This 'EMR' (Electricity Market Reform) programme has been spelled out in a number of government papers[30] and is also embodied in the Energy Act which

[30] Notably, (1) Department for Energy and Climate Change (2011), 'Planning our electric future: a White Paper for secure, affordable and low-carbon electricity', July and (2)

passed in December 2013. The origins or EMR derive from the 2008 Climate Change Act and, more importantly, the Climate Change Committee (CCC) 5-year carbon budgets as set out in CCC reports of 2008-09.

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The two most important components of EMR are:

- so-called ‘contracts for difference (CfDs)’ which will be put in place between a government agency and new low-carbon generators – reducing the revenue risk faced by these generators; and

- a capacity market/mechanism which will pay generators (and providers of demand-side reduction) for availability to balance supply and demand when required to do so by the SO.

Note that the CfD –FiT payments to generators are made within a levy control framework which sets out maximum expenditure levels. They are recovered by a levy on suppliers[31].

3.2 The UK Energy Market Reform, SO Arrangements and Renewables

In the context of this paper, the significance of the EMR proposals lies in what they entail for the role of the Great Britain System Operator (GBSO), National Grid. In broad terms, National Grid has, in its SO role, been designated as the ‘delivery agent’ for EMR. In doing so, it works directly with DECC (the UK government department responsible for energy) and with Ofgem (the UK energy regulator) responsible for monitoring delivery of the various obligations. More specifically, GBSO has been assigned a number of tasks in relation to the allocation of CfDs and operating the capacity mechanism.[32]

- In relation to CfDs, the SO’s functions will include, in particular:
    - providing the data and analysis for ministers to decide on the level of support for different (generation and demand-side) technologies;

Department of Energy and Climate Change (2011), ‘Planning our electric future: technical update’, December.

[31] See M. Pollitt, ‘Wholesale and retail market reforms in the UK: What not to do.’, 2013. See also J. Stern, ‘UK Renewables Demonstration Projects: Who Pulls the Plug?’, 2014, Regulatory Policy Institute.

[32] The following description of the SO’s role in EMR is based on Annex D of Department of Energy and Climate Change and Ofgem (2013), ‘Synergies and Conflicts of Interest arising from the Great Britain System Operator delivering Electricity Market Reform, Final Report’, April.

- o running the process of choosing which companies get contracts, based on assessment of eligibility criteria set by government and within budgetary limits set by the government.

- In relation to the capacity market, the SO's functions will include:
  - o providing the evidence and analysis for Ministers to decide how much capacity will be needed;
  - o deciding which sorts of plant fulfil the requirements to participate in the capacity market;
  - o running a competitive auction for providers of capacity;
  - o monitoring the performance of capacity providers.

Put another way, the UK government effectively wants to move the electricity industry away from a 'competition *in* the market' model (with generators and suppliers competing against each other on a continuous basis) to 'competition *for* the market'. Once a generator has received its CfD or capacity contract, it largely competes against that contract, rather than against other generators.

However, a 'competition for the market' model requires a body to run the competition(s) for that market. In the case of EMR, the government has chosen the SO for this role. Its stated reasons for doing so include:

> 'strong synergies with the current role of the System Operator and the delivery of both the FiT CfD and the Capacity Market'; and
>
> 'the System Operator already has the technical expertise and commercial and financial skills necessary to deliver the FiT CfD and the Capacity Market'.[33]

This may be technically correct, but what really seems to be going on here involves deeper issues about the role of the state in relation to politically sensitive industries (and few industries are as politically sensitive as electricity). One of the deeper political instincts is to want to have a reliable instrument – somebody to go to – to sort out politically sensitive problems, rather than leaving them to some abstract entity such as 'the market'. (In this respect, as in others, the period from the late 1980s to the early 2000s was an anomaly in UK energy history.) As already noted, the government could have chosen to achieve decarbonisation of the electricity industry through market mechanisms, but it chose the route of having a body putting in place contracts for the mix of generating plant that the Government thinks is required.

In the case of the electricity industry, having a state-owned vertically integrated company offers a straightforward answer to the question of 'Who's in charge?' However, in a privately-owned vertically disintegrated industry such as the current UK electricity industry, the SO, with its position at the heart of operating the industry, offers the next best thing.

[33]Department of Energy and Climate Change (2011), Planning our Electric Future: Technical Update', December, para 70.

Hence, the GBSO – run by the national transmission company – becomes the agency by which the Government's technology choices are delivered, particularly over renewable generation obligations.

As Dieter Helm expresses it, "The result [of EMR and related developments] is that nothing much is built except through fixed price contracts …. The system becomes a complete single buyer model with the state through the system operator determining investment. The wholesale market is no longer the economic signal for new investment …."[34] Hence, the co-ordinator SO for the pre-2008 liberalized electricity system is transformed into the plan-making and delivery SO agency for a state-dominated electricity system

In sum what is being played out here is the consequence of the combination of:

(a) the politically high profile of the electricity industry, particularly since the onset of the 2008 recession and squeeze on household living standards;

(b) the particular requirements of post 2008 EU environmental impulses and legislation under the 20-20-20 provisions;

(c) the fact that there are various restrictions (notably EU restrictions) on 'distortionary' state support of energy markets under State Aid rules; and

(d) the fact that the electricity industry in the UK (and elsewhere) is no longer a state-owned vertically integrated monopoly.

When the UK industry was in state ownership, it could simply (or, often, not so simply) be 'required' to deliver government policy objectives. Thus, in the 1980s and 90s, the CEGB (Central Electricity Generating Board) was required to buy expensive British coal, rather than cheaper alternatives, and was required to cross-subsidise certain large industrial consumers. Within the current structure of the GB industry and current EU energy legislation, there is no such option, particularly in respect of securing the build of new nuclear power stations.

The SO offers the best alternative instrument other than state monopoly ownership available to achieve current government objectives. However, as discussed below, the use of the GBSO to do this has caused a number of problems both at national and EU level.

3.3 Discussion and Future Prospects for the UK and its Relationship to EU Energy Policy

The development of the UK EMR programme as a way of meeting the UK's EU 2020 (and later) climate change and renewable electricity policy targets has been much criticized; it has also been fraught with difficulties. The EMR reform programme was started in 2010 but, almost 4 years later, some key elements remain to be settled (e.g. on the capacity payments regime).

In addition, as discussed in the next section, there have been major developments at EU level and the EU Single Electricity Market, which was originally based on a liberalized unbundled model, is now having to adjust to a very different world. *National* renewable targets (and

[34] D Helm (2014) 'Politically Toxic Prices'. See also (2013) Labour Energy Policies'

subsidy policies) together with *national* capacity payment arrangements are now spreading and this has caused problems for the development of the Single Energy Market. These problems are illustrated in the December 2013 DG Competition's Draft Guidelines on environmental and energy aid and also the January 2014 EU Commission energy policy framework for 2020-30. For the UK, combining EMR and its key provisions with EU policies is hard and could raise profound state aids problems.

Many of these issues go well beyond SOs and their role. In what follows, the focus will be on SO implications for Britain, including state aid issues.

3.3.1 The UK EMR Programme and the Role of the SO

The British EMR programme has been much criticized and it has proved very hard to resolve some of the key issues. There are still no firm dates as to when the CfD and capacity payment arrangements will come into operation.

Some of the more obvious issues are as follows:

- *GBSO is the designated delivery agency for the CfDs but it will not hold or own the CfDs.* The CfD counterparty will be some (as yet unidentified) government owned agency. Commentaries by law firms on these arrangements have identified various difficulties[35];

- *There have been major concerns over conflicts of interest between GBSO in its 'regular' SO role and in its role as delivery agency for the technologically determined generation programme.* These concerns led to a joint DECC-Ofgem review of the potential problems, which was published in 2013 together with the government's proposed mitigation measures[36]. The review recognized various potential problems and suggested various mitigation measures in terms of transparency, ring-fencing of functions, controls on information flows and additional regulation.

  Very interestingly, of the 16 industry respondents to the consultation (mainly generation companies or similar industry representatives), 12 of them argued the need for legal and/or ownership separation of the EMR commissioning functions of GBSO (and 2 argued for some lesser business separation). DECC, though, rejected these arguments, primarily because of the loss of GBSO and system synergies. However, the DECC Impact Assessment for the proposals showed that the Net Present Value of all 5 options considered was very similar – particularly as between the separation option and the chosen option. The Impact Assessment made clear that the choice of DECC's preferred option over the industry's preferred separation option was very largely due to perceived SO-EMR synergies[37]. That leaves the obvious question of whether and when positive synergies raise sufficient conflicts of interest as to yield negative net benefits.

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[35] See, for instance, Norton Rose Fulbright December 2012 and Allen and Overy July 2013.
[36] See 'Synergies and Conflicts of Interest arising from the Great Britain System Operator delivering Electricity Market Reform', DECC and Ofgem, April 2013.
[37] See 'Impact Assessment of measures to address potential conflicts of interest in relation to the choice of National Grid as the delivery body for EMR' *IA No. DECC0135*. See p.40 for the overall justification.

- *CfD and Capacity Market Coverage.* It is still unclear what generation technologies will be covered by CfDs and capacity markets – and how non-UK generators (and interconnectors) will be covered. This will affect the role of GBSO as the delivery agency. As discussed in more detail below, a variety of potential State Aid problems have arisen with the EMR programme. An early coverage example is whether UK energy intensive industries can be exempted from the costs of CfDs, as the UK government has proposed.

- *EU State Aids Policy.* A number of elements of the EMR programme have been caught up in State Aid investigations. Firstly, the EU Commission has opened an in-depth investigation into the 35-year Hinkley Point nuclear contract with EDF. This contract was not subject to any bidding process, which is one reason why it may have been vulnerable to state aid action. (The EU Commission approved a revised application on 8 October 2014). In addition, the Commission has also opened investigations into, firstly, proposed subsidies for renewable energy projects via the CfD subsidy scheme; and, secondluy, for assistance to Drax for its conversion from coal to biomass.

  Similar EU investigations of state aid schemes have been taken against other EU member states, most obviously Germany. It remains to be seen whether some or all of these schemes have to be dropped or significantly modified as a result of the application of EU State Aid rules. However, more seriously, questions have been raised by Malcolm Keay of OIES and some of the legal commentators as to whether the British CfDs, capacity payments and other elements of EMR (including the capacity payments regime) are *in general terms* consistent with EU competition policy and EU state aid policy[38]. They suggest that EMR may raise fundamental inconsistencies with EU competition and state aids policy as applied to the energy sector.

  These state aid decisions will affect how GBSO can operate its EMR delivery function.

- *Costs*. In 2004, climate change policy costs represented around 3% of a typical household domestic electricity bill with annual consumption of 3.3MWh. This rose to over 12% in 2005, largely because of EU ETS prices. It peaked at 14% in 2008 with the rise in the costs of the renewables obligation and high EU ETS prices, but even though the latter have fallen back, it has remained around 14%[39].

  Projections of the impact of EMR and other climate change and renewables policy changes in 2011 by DECC indicated household increases in bills of 32% in real terms by 2030. Over 80% of that was policy induced even assuming increased gas prices. (The real price increases for industry and commerce ranged from 56% for medium non-domestic consumers to 69% for energy intensive industries.)[40]

  The implications of these policies on household bills has had sufficient political implications for the Chancellor of the Exchequer in December 2013 to transfer some

[38] See Malcolm Keay 'UK Electricity Market Reform and the EU', OIES, April 2013 and Allen and Overy's EMR Update July 2013.
[39] See Chawla and Pollitt (2012).
[40] See Pollitt (2013).

of the efficiency policy costs from consumers to taxpayers. The average amount transferred was claimed to equal £50 per year per household.[41]

4. Project Target, Virtual ISOs and the EU Single Energy Market

Since 2008, the EU has pursued the policy of trying to create a Single European Electricity Market. The basis of this is the Project Target Model which is heavily based on the Nord Pool arrangements. In terms of SO arrangements, the Project Target model – like the Nord Pool arrangements - relies on a 'virtual' ISO. The UK electricity reforms discussed in the previous section are intended to be consistent with this EU programme but it is far from clear that they are consistent. In this section, we discuss the relationship between the two, focusing primarily on SO arrangements. In particular, we consider the degree to which the change in the objectives of the British SO firstly reflects wider EU debates; and, secondly, may prove a model for other EU countries.

As set out in the December 2013 EU Commission Energy Policy Document, the Project Target model remains the focus for the construction of the EU Single Electricity Market. However, the UK model and other member state 'national planning' variants is becoming a major challenger to the market-based regional country grouping model. As in the UK, the 'national planning' electricity and SO models are largely based on technologically chosen (and subsidized) renewable generation plus capacity payments for other generation.

4.1 The Project Target Electricity Model and 'Virtual' ISOs

The key features of the Project Target electricity model are

(i) 'Virtual' rather than explicit ISOs or ITSO in each electricity region, with individual country ITSOs, ITOs or ISOs;

(ii) No supra-national regulatory agency for the region;

(iii) Regional PBX's and market coupling, with implicit transmission auctions, to provide short and medium term co-ordination;

(iv) Rules for operation set out by Network Codes issued by ENTSO-E and approved by ACER after extensive discussions at the Florence Forum, with CEER and others;

(v) Investment co-ordination by national companies and national regulators. TO (and rather smaller SO) investment approved and financed by national ITSOs and ITOs.

The most important Project Target regional grouping so far established is CWE – the Central Western European market coupling – which covers Belgium, France, Germany, Luxembourg and the Netherlands. It was set up following outline agreement in 2007. CWE and Nord Pool were linked by links with Denmark and Norway from 2010.

[41] See https://www.gov.uk/government/news/autumn-statement-2013-key-announcements

Besides CWE, there are similar markets for (i) Portugal and Spain (ii) Italy and Slovenia and (iii) the Czech and Slovak Republics. They also have the Target Model as the basis for their operation and, presumably, the intention is to link them with the CWE market to give a Single European Electricity Market – originally planned for 2014/15 but now well behind schedule[42].

In many ways, the Project Target model has been very successful. Since CWE has been in operation, wholesale prices have converged in *all* CWE countries over 65% of the time[43]. However, a recent CERRE report identified a number of major issues with the virtual ISO approach. For short and medium term operational issues, the following problems were identified:

(i) *Will a 'virtual' ISO model provide sufficient inter-TSO co-ordination between members of regional groupings, not least in emergencies?*

(ii) Will a Nord Pool-type model work as well in the rest of Europe as in the relatively unmeshed transmission networks of the Scandinavian countries?

(iii) Will a Nord Pool-type model work as well when it has to combine national and sub-national ITSOs and one or more ITO, as in the CWE market?

(iv) *How well will the Nord Pool-type model and its 'virtual' SO arrangements cope with substantial (and growing) volumes of intermittent renewable generation?*

(v) *Will there be a need for transitional (or even permanent) compensation arrangements as trade flows develop?*
Unless there is considerable inter-country complementarity between types of generation within regional power markets, some power companies, consumers and member states will gain significantly from more regional market trade and others will lose. How will this be handled within Project Target and will there be pressures for temporary if not permanent compensation arrangements involving national TSOs and the regional markets?

(vi) *Will the new arrangements be able to accommodate capacity payments?*
The existing European power exchanges (including Nord Pool) are all energy-only markets, without capacity payments. Given the growth of intermittent wind generation and other factors, the UK is proposing to reintroduce capacity payments under its EMR project. Can capacity payments readily be reconciled with the Project Target Model and its (non-) SO framework[44]?

This last issue raises particular problems if some countries in a regional market adopt capacity payments but others do not. This already arises within CWE.

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[42] For a full exposition and appraisal, see Chapter 4 of the 2012 CERRE Report 'The Role of System Operators in Network Industries', J Stern, M. Cave and G. Cervigni.

[43] See Booz et al, op cit, p.25-26.

[44] See G. Cervigni, 'Generation capacity adequacy in Europe : What economic rationale for Capacity Remuneration Mechanisms', CERRE, 2013 for a good discussion of these issues.

4.2 Virtual ISOs and the EU Single Energy Market: Transmission Investment and Interconnection

Recent EU electricity policy documents have promoted regional multi-country markets but with significantly additional interconnection between countries. This is intended to promote intra-area security (particularly with intermittent wind and solar generation). This policy has been set out clearly in the January 2014 EU Commission Energy Policy 2020-2030 document. This document proposes a policy of more market coupling and interconnection rather than a set of national-based policies with extensive, individual country state subsidies for renewable generation and national capacity payments. This EU approach is echoed in the December 2012 DG Competition document about state aids for renewable generation

Previous sections have discussed the UK's EMR proposals which seem the opposite of the EU Commission approach. EMR reintroduces extensive planning via a delivery-oriented SO; it provides for extensive national renewable subsidies – primarily but not exclusively for non-mature technologies; and it reintroduces capacity payments. This, not surprisingly, is one reason why commentators have asked whether and how far EMR is consistent with emerging EU policy.

However, the EU approach based on virtual SOs has major potential problems. The main one is whether and how the Project Target model can achieve an adequate level of transmission investment – particularly in interconnection. This is the Achilles Heel of electricity ISOs, even explicit ISOs.

ITSOs resolve the problem by internalizing the externalities, albeit at a cost of weak pressures on TOs for innovation and cost efficiency. However, for all non-ITSO SOs, actuating adequate transmission investment has been and remains a problem. It is the key weakness in US ISO/RTOs. This is true in general and it is worse in multi-area ISOs than in single area ones, not least because of multi-regulator problems. Within the British electricity system (which operates as an ISO), GBSO has much more limited influence over transmission planning in Scotland than it has in England and Wales. (National Grid operates GBSO but owns the England and Wales ITSO). GBSO also has very little influence over planning offshore transmission investment or new interconnectors[45].

The EU Target Model recognizes this issue but is less willing to confront it. Neither power companies nor national governments are willing to install explicit multi-area SOs. That leaves an even bigger problem in how to raise the long-recognised very low rate of inter-connector transmission investment which is essential to make the regional and EU-wide electricity markets function effectively and efficiently. Instead, there is the hope that inter-country co-ordination (including national regulatory co-ordination), augmented by catalyst funds from the EU will sufficiently support interconnector and other necessary transmission investment.

Having national ITSOs as the most common national SO choice may help, but reliance on 'virtual' regional SOs to handle this issue satisfactorily seems to be a triumph of hope over experience. It has manifestly failed in the US RTOs, so why should it be expected to succeed in the EU where governments and others may well act to protect national markets and where

[45] I am grateful to Tim Tutton for information on GB transmission planning.

there is a weaker multi-area market design and regulatory background? ACER is far from an equivalent of the FERC in terms of specified powers and duties.

A key issue is that increased inter-connection which removes bottlenecks creates losers as well as winners. Transmission companies and protected generators lose revenues where new bottleneck-relieving transmission investment increases the scope and effectiveness of competition – particularly between jurisdictions (e.g. EU member states). That can result in higher prices to own-country consumers from higher exports as a result of additional, congestion-relieving interconnection[46]. For this and other reasons, that is why significant additions to interconnection – and the SO-type institutions that might create them - have so far been heavily and consistently resisted.

One of the underlying issues is that congestion payments are insufficient to fund new interconnections and that the main beneficiaries may not be the TSOs (or countries) funding the investments.

It is difficult to see how the 'virtual' SOs are likely to change this via the incentives available to them, which is why there are calls for giving powers to regulators (or the Commission) to mandate interconnector investment.

There have been explicit calls for an EU-wide ISO to tackle this problem. Lévêque, Glachant et al (2008) recommend explicit ISOs for multi-area systems, where cross-border externalities and cross-border competition are important relative to national network investment and reducing transmission costs. They point to the benefits of regional market operation and network integration from ISOs where separate transmission companies continue so that price cap regulation for the network is not possible. These are broadly the circumstances for which the Target Model was designed[47].

It remains to be seen how far the British SO experience reflects developments in other countries. It seems most likely to do so in other countries with heavy dependence on wind and solar power (e.g. Germany and Spain).

5. Concluding Comments

There is clearly a major developing battle between (a) EU Commission and other proponents of a liberalized, competitive EU electricity market based on high levels of interconnection; and (b) the competing nation-based approaches which include some or all of: firstly, large-scale investment on national renewables; secondly, sizeable budgetary subsidies; and, thirdly, capacity payments.

The UK is firmly in the latter camp – not least because its electricity system is only weakly interconnected with other countries. However, the policy has primarily been adopted because the government wants to keep these issues under its control rather than relying heavily on

[46] See Booz et al, op cit, p.19.

[47] See also Glachant and Khalfallah (2011) which clearly advocates an EU-ISO to co-ordinate network operation and investment planning in a transparent way, independent of local interest groups. This EU-ISO would be supported by various methods of encouraging cross-border co-operation and investment planning, including a very much larger TEN program fund and obligations on national regulators

markets and electricity supplies from Continental Europe and Ireland. Hence, it is not surprising that state aids concerns have become so important for the UK EMR proposals.

A key factor on that is that the UK, like Germany and Spain, has developed proposals that emphasise the role of intermittent renewable generation (for the UK, offshore wind) in tackling climate change. That and UK nuclear generation appear to require long-term contracts with subsidy support (via CfDs) and capacity payments. Hence, the need for new coal and gas generation also to purchased via long-term contracts under a single buyer approach.

SO arrangements play an important part in this battle. The previous section discussed how and why GBSO (the British system operator) has become transformed in under five years from a market co-ordinating agency to a state planning and delivery entity. There are major questions as to how efficient the new system and the delivery SO will be, but –provided the government allocates sufficient funding under the levy framework – it should deliver the government's required policies. Of course, future governments may change the policy or restrict levy funding and this would affect GBSO's role insofar as it changed the policy objectives.

SO arrangements are also very important for the EU Commission's approach. It appears to depend heavily on greater interconnection to encourage multi-country regional markets and to link up those markets into a Single European Electricity Market. But, are virtual SOs supported by ENTSO(E) codes sufficiently powerful to do this?

Experience from the US RTOs with explicit ISOs and a Federal energy regulator indicates problems and the proposed EU co-ordination and regulatory arrangements are much weaker. Of course, the EU Commission's Single Market proposals may be made significantly less ambitious under pressure from the Member States. If so, having only virtual ISOs at regional level would be less of a problem. But, virtual ISOs do not look strong enough if the EU does intend to continue with multi-country liberalized markets as the best way to improve efficiency and reduce prices – while adequatetely addressing climate change. There is also the question of aligning the SO arrangements with EU and national regulatory arrangements – an issue that has not been much discussed publicly.

SO arrangements for electricity are determined by how generation markets develop within defined policy frameworks. For the UK, from 1990-2008, we had liberalized and unbundled generation and wholesale supply markets. That required a co-ordinating SO which was a part of National Grid, the relevant ITSO. However, the EU '20-20-20' climate change policies with their weight on intermittent, high cost renewables effectively destroyed the viability of the England and Wales wholesale generation markets – as the UK government was warned that it would. In consequence, the UK has now had to invent a single buyer-like planning SO to deliver the renewable and nuclear generation.

SOs and their objectives are very good indicators of the focus of electricity policy and its requirement on market design. SOs in the EU seem to be taking on many functions – arguably too many, including quasi-regulatory functions of the kind that US RTOs have done. We shall see in coming years how the EU debate unfolds and whether other EU Member States travel down the same road as the UK has done.

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