UNIVERSITY OF CAMBRIDGE | Energy Policy Research Group

Strengths and Weaknesses of the British Market Model

EPRG Working Paper 1907

Cambridge Working Paper in Economics 1917

David Newbery

Abstract

The UK privatized the electricity supply industry from 1989 in the expectation that private ownership and incentive regulation would invest and operate sufficiently more efficiently to offset the higher cost of private finance. This was achieved in the first two decades, assisted by spare capacity, contract-based entry of new efficient and cheap CCGTs, and regulatory pressure on transmission and distribution companies. The climate change imperative to decarbonize requires massive durable and very capital-intensive investment that casts doubt on the liberalised financing model. In the past 30 years, much has been learned about mitigating market power, the failings of an energy-only market, and the potential distortions of poorly designed prices for renewables and tariffs for networks. Innovation has been successfully stimulated through competitions. Efficiency, falling renewable costs and the carbon tax have almost completely driven coal out of the system.

Keywords British electricity supply, reforms, financing, renewables, tariffs, nuclear

JEL Classification D43,D47, H23, L94, Q48, Q54

Contact: dmgn@cam.ac.uk

Publication February 2019

Strengths and Weaknesses of the British Market Model[1]

David Newbery
EPRG, University of Cambridge
20 March 2019

Abstract
The UK privatized the electricity supply industry from 1989 in the expectation that private ownership and incentive regulation would invest and operate sufficiently more efficiently to offset the higher cost of private finance. This was achieved in the first two decades, assisted by spare capacity, contract-based entry of new efficient and cheap CCGTs, and regulatory pressure on transmission and distribution companies. The climate change imperative to decarbonize requires massive durable and very capital-intensive investment that casts doubt on the liberalised financing model. In the past 30 years, much has been learned about mitigating market power, the failings of an energy-only market, and the potential distortions of poorly designed prices for renewables and tariffs for networks. Innovation has been successfully stimulated through competitions. Efficiency, falling renewable costs and the carbon tax have almost completely driven coal out of the system.

[1] Written as Chapter 5 for the *Handbook on the Economics of Electricity,* eds. J-M. Glachant, P. Joskow and M. Pollitt.

Strengths and Weaknesses of the British Market Model[2]

David Newbery[3]
EPRG, University of Cambridge
20 March 2019

1. The British Electricity Market 1947-89

The British model has evolved to cover the island of Great Britain (England, Wales and Scotland), while Northern Ireland, part of the UK, has evolved into a quite different market model covering the island of Ireland in its Single Electricity Market (SEM). This chapter discusses the British market — its relationship to the SEM is discussed in Newbery (2017). The main emphasis here is on England and Wales, which experienced the main restructuring. Scotland had two vertically integrated regional state-owned utilities which retained their unbundled structure after privatization.

Before restructuring and privatization in 1989-90, the state-owned Central Electricity Generating Board (CEGB) owned generation and transmission in England and Wales. Transmission and site location of new generation was coordinated by the CEGB, although the main high tension (440kV) grid had been largely completed by the 1960s with substantial spare capacity. Similarly, the intense period of building large power stations (with 660 MW turbines) was predicated on continued growth in demand of 8% p.a. that had come to an abrupt halt with the first oil shock. The stations under construction would deliver substantial excess capacity once completed. Distribution and supply (retailing) were managed by 12 Area Boards, who paid the CEGB the Bulk Supply Tariff and set tariffs for their captive retail customers.

The Bulk Supply Tariff (BST) evolved into a two-part fixed charge (base and peak) per kW, allocated on the basis of the Area Boards' use of base and peak capacity of both transmission and generation. A variable energy charge was set equal to the marginal energy cost (varying between night time, shoulder and peak periods). With a growing nuclear share and large coal stations that cannot be rapidly stopped and started, the problem was excess capacity at night and excess demand at the peak. The solution was to build very costly pumped storage schemes and to introduce cheap rates for night-time electrical storage units, both storing either power or heat for later use. Meek (1968) compares this tariff structure with the theoretical ideal more closely followed in France (where Boiteux was both the theorist behind such tariffs and the head of EdF),[4] foreshadowing the tariff problems created by high renewables penetration with similarly high fixed and very low variable costs. Trade with France was through balanced bilateral swaps designed to benefit from the one-hour difference in timing of peak demand.

The CEGB's performance had been strongly criticized for its inefficiency, particularly in delivering timely and cost-effective investment, and under-pricing its output (Henney, 1994; Newbery and Green, 1996). After the success and lessons learned from earlier UK

---

[2] Written as Chapter 5 for the *Handbook on the Economics of Electricity,* eds. J-M. Glachant, P. Joskow and M. Pollitt.

[3] I am indebted to anonymous referees for the EPRG WP and Mike Waterson for helpful comments.

[4] Boiteux (1949)

utility privatizations, the CEGB was ripe for restructuring to create competitive wholesale and retail markets, and regulated transmission and distribution networks (Newbery, 2000).

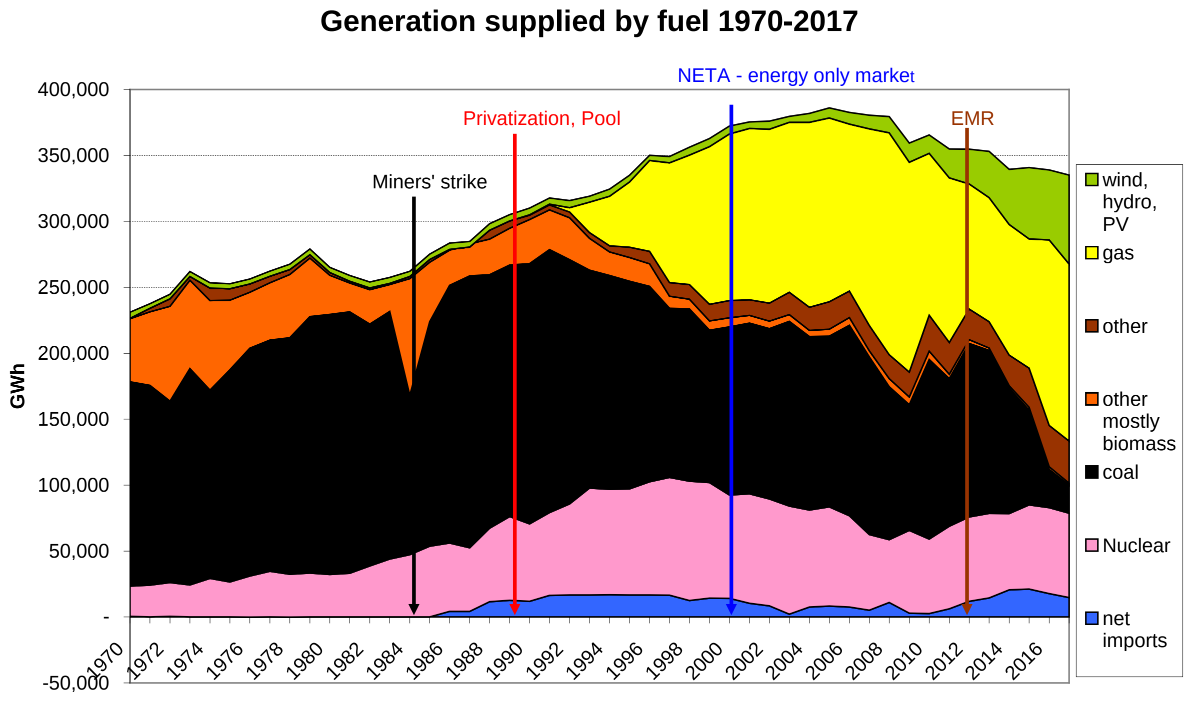

Figure 1: UK Electricity Generation by Fuel, 1970-2017
Source: BEIS (2018), DUKES (2018 ch. 5)
Note: "other" is all thermal generation from other generators (i.e. not the public supply companies), non-CCGT gas and thermal renewables. Pumped storage (net negative) is not shown, but (small) amounts of annual average exports are shown negative. NETA is the new Electricity Trading Arrangements, EMR is Electricity Market Reform, both discussed below

2. Privatization, restructuring and market power

The CEGB was restructured in 1989 to separate transmission and generation. The 12 Area Boards became Regional Electricity Companies with temporary ownership of National Grid. The networks were subject to price-cap regulation by the Office of Electricity Regulation, Offer. All were privatized in 1990 with the exception of Nuclear Electric that was finally sold in 1995. The vertically integrated Scottish companies were privatized unrestructured in 1991.

Figure 1 shows the evolution of the fuel mix from 1970 (after the shift from coal to oil in the 1960s). By 1989, just before restructuring for privatization, around 90% of the conventional thermal generation was from coal, 7% from oil and the remainder largely from industrial by-product gases. The share of oil rapidly fell to 1% in 2002. After privatization, the coal share declined as imported electricity and nuclear power increased. It declined more rapidly with the 'dash for gas', which was all new build gas-fired Combined Cycle Gas Turbines (CCGTs) despite the considerable spare existing capacity.

The market structure of generation in England and Wales was initially highly concentrated in two price-setting fossil companies, National Power and PowerGen. The state-owned Nuclear Electric (whose eight modern stations were privatized in 1995 and restructured in 1996 to become British Energy, leaving the old Magnox stations in British Nuclear Fuels LTd, BNFL in figure 2) was a price-taking base-load company. National Power was structured (as “BigGen”) to be large enough to carry the risks of owning the nuclear power stations, whose performance had been poor and whose accounts were opaque. PowerGen (“Little Gen”) was two-thirds as large to provide a sufficient counterweight to National Power. The city baulked at underwriting the unknown risks of the nuclear stations, so the nuclear stations were pulled out of National Power and kept in state ownership. By then it was too late to choose a better market structure. Henney (1987) had argued for breaking the CEGB into 10 companies (there were 10 large coal-stations), while Green and Newbery (1992) argued that five companies would have created a workably competitive structure, a conclusion endorsed by the Competition and Markets Authority (CMA, 2016) in their study of the six large energy companies selling electricity and gas.

Figure 2 shows the evolution of the market structure in England and Wales from a de-facto price-setting duopoly to a competitive structure just before the 2001 New Electricity Trading Arrangements (NETA) were imposed.

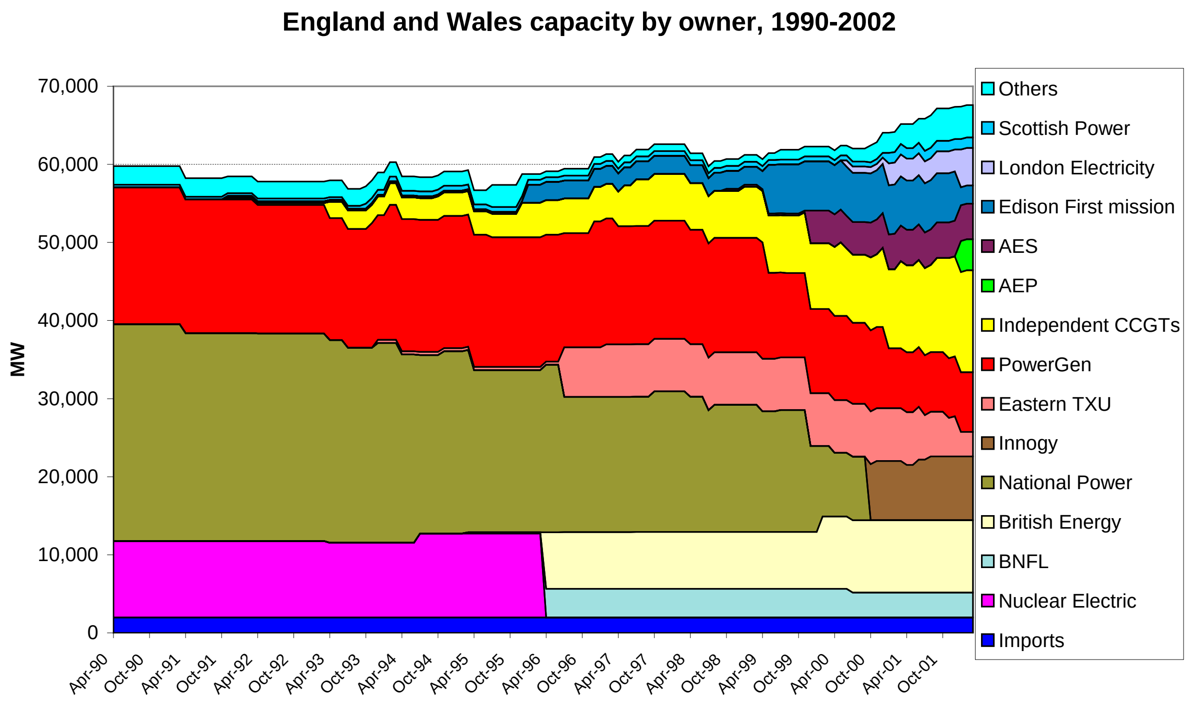

Figure 2 Output by company in England and Wales
Source: National Grid, *Seven-year statements*, various years[5]

All generators (above 50MW) offered plant into the Electricity Pool day ahead, specifying the prices and quantities for each unit, which the System Operator used to determine the unconstrained System Marginal Price (SMP, the price of the last plant accepted). Market power allowed the two companies to game the Pool and exploit capacity constraints that had been efficiently managed under the CEGB’s central dispatch. Constraint

[5] These have been superseded by National Grid, *Electricity Ten Year Statements*, available: https://www.nationalgrid.com/uk/publications/electricity-ten-year-statement-etys

costs rose rapidly, until National Grid as System Operator convinced Offer to provide incentives for their better management (although they remained higher than necessary).

Newbery and Pollitt (1997) concluded that the way the CEGB had been privatized to unbundle generation and transmission combined with an open-access wholesale market (the electricity Pool) created substantial value (equal to a permanent cost reduction of 6%) but that the benefits were more than appropriated by the new owners of the generation assets. In Scotland, vertical integration appeared to obstruct any efficiency gains, and consumers (and tax payers) lost to the owners of the new companies (Pollitt, 1998; Domah and Pollitt, 2001). The lesson was clear, privatization without restructuring to introduce competition was not necessarily beneficial, and an imperfectly competitive structure prevented efficiency gains being passed through to consumers. It would have been better to introduce competition before privatization and avoid the lengthy regulatory struggles and the fortunate arrival of cheap gas-fired stations to slowly rectify that mistake.

The consequences of market structure on electricity prices have been elegantly teased out by Sweeting (2007) and illustrated in Figure 3.

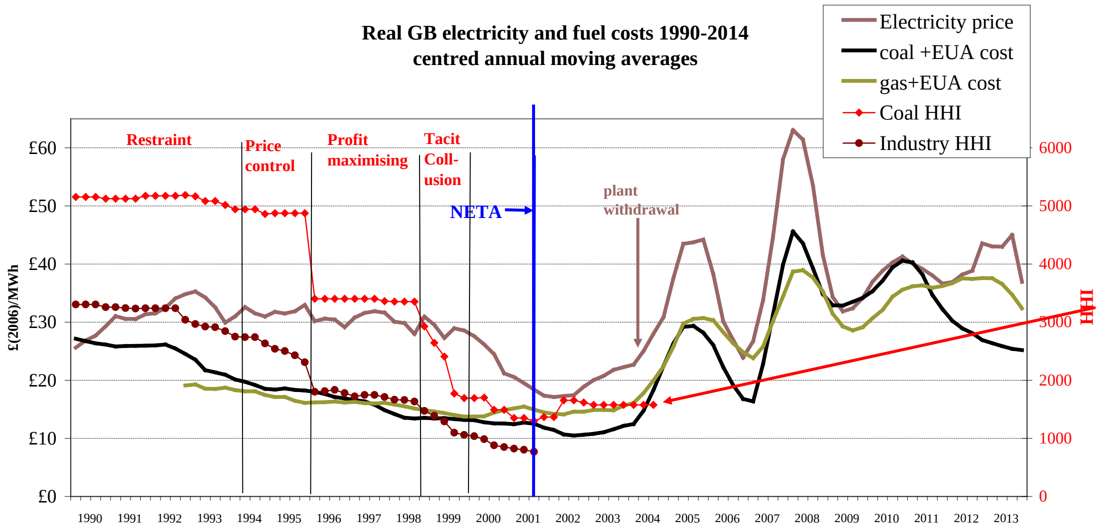

Figure 3 Wholesale electricity and fuel costs, 1990-2014 and market concentration
Source: : NGC *Seven Year Statements*, various years, and data from J Bower and C Humphries (Bower, 2002)

HHI,[6] the Herfindahl–Hirschman Index, is shown for the price-setting coal stations. The first period 1990-94 was one in which NP and PG were privatized with sales contracts with the Regional Electricity Companies (RECs) and purchase contracts for coal from the state-owned National Coal Board, giving revenue and cost certainty needed for their sale prospectuses. Contract cover mitigates market power (Allaz and Vila, 1993, Newbery, 1995), but as the contracts fell away, the price-cost margin rose, restrained only by the threat of a monopoly inquiry. In 1994, to avoid a reference to the Monopolies and Mergers Commission, NP and PG agreed a price control with Offer, to last until they had divested 6 GW of their 20 GW of coal plant to Eastern TXU, shown in figure 2. The sale came with an "earn-out" charge of £6/MWh, ostensibly to cover the cost of the sulphur permits that went with the

[6] The HHI is the sum of the squared market shares in percentages, with 10,000 a perfect monopoly, 5,000 a symmetric duopoly and above 1800 indicating significant market power.

stations sold (Newbery, 2005), but raising costs to Eastern TXU causing it to set the wholesale price much of the time. This allowed the three companies to maximise their profits, as the original duopolists could hide behind Eastern.

Before 1998 the duopolists were blocked from buying the supply businesses from the distribution companies. In 1998 the Government allowed vertical integration to take place in exchange for further divestment and ending the “earn-out” clause (Newbery, 2005). Sweeting (2007) characterises this period as one of tacit collusion, in which National Power and PowerGen aimed to sustain the wholesale price as market concentration rapidly fell with divestment. Arguably National Power (which became Innogy in October 2000) and PowerGen played a long game in which the original quasi-referral by Offer with a price cap and divestment demonstrated their ability to sustain market power, followed by a demonstration that divesting plants if anything increased their price-cost margin. This encouraged new entrants to buy old coal stations to diversify their plant mix (British Energy, the nuclear power company, having failed to buy a supply company (a more sensible hedge) bought a coal station instead (Taylor, 2007). High price-cost margins convinced potential buyers of their profitability, ensuring a high price for such plant. Buying retail businesses allowed generating companies to hedge internally against wholesale price movements, a strategy that Nuclear Electric tried and failed to follow, with subsequent disastrous results as it subsequently went into administration (Taylor, 2007).[7] Internal hedges reduce wholesale market liquidity that deters entry of competitive retailers, leading Ofgem[8] (eventually) to encourage all sales to be transacted through a (moderately) transparent wholesale market.

3. Competition and the switch to an energy-only market

As divestment created lower concentration, the structure evolved towards the current “Big Six” generation plus retailing companies.[9] As the new buyers started competing (believing somewhat naively that they could raise their plant load factors from 20-40% without impacting price) so Figure 3 shows the wholesale price collapsed and the market finally became workably competitive, albeit in the face of quite wildly fluctuating fuel prices.

Before that price collapse, however, Offer remained concerned about the persistence of market power in the wholesale market, despite all the divestment. To address that, it pressed to abolish the Pool and replace it by a bilateral energy-only market termed the New Electricity Trading Arrangements (NETA). Generators would have to contract with buyers to submit a balanced physical position to the System Operator by Gate Closure (an hour before dispatch). The argument, noted above, was that fully contracting removes the incentive to manipulate the spot market. To encourage full contracting, imbalances were settled through the Balancing Mechanism (not a market) at penal buy or sell prices (depending whether the agent was short or long). This was enthusiastically accepted by the Big Six who were now vertically integrated. They were effectively already hedged internally with little need to trade

[7] Nuclear Electric also imprudently bought one of the divested coal stations, and along with other buyers suffered a 50% loss in value after a few months when wholesale prices collapsed.
[8] Offer became Ofgem, the Office of Gas and Electricity Markets, in 1999.
[9] The Six Large Energy Firms are Centrica (originally a gas monolist), SSE plc, RWE npower, E.ON, Scottish Power and EdF Energy (who bought the nuclear stations from the bankrupt British Energy).

bilaterally, while the illiquidity of such trading over the counter and the penal Balancing Mechanism helpfully deterred entry. Newbery (1998) criticised the proposed reforms then under discussion, while Bower (2002), Evans and Green (2003) and Newbery (2005) argued that by 2001 they were redundant because of the pre-existing development of competition. Ofgem estimated that market participants could incur total costs of up to £580 million in implementing NETA over the first 5 years.[10] In a careful econometric study, Giulietti et al. (2010) examined the impact of NETA on final consumer prices, which include retail margins and other (unchanged) costs in addition to wholesale prices. They find a sharp increase in the retail margins in England and Wales compared to Scotland (where NETA was not introduced until later), strongly suggesting that NETA raised retail margins. The new market design made entry by retailers lacking generation much riskier as they now had no Pool reference price on which to contract.

It has taken nearly 400 modifications to make the Balancing Mechanism fit for purpose and closer to a single price balancing market.[11] It took a further major reform of the electricity market in the *Energy Act 2013* (HoC, 2013) to restore a capacity market and address other market failures (Newbery, 2012, 2016). The resulting Energy Market Reform (EMR in fig. 1) made the market reasonably efficient in the eyes of the Competition and Markets Authority (CMA, 2016). After over a decade some of the virtues of the original Pool, with its single price, liquidity for contracting, ease of entry, and a scarcity element in the form of a capacity payment were once again realised (Grubb and Newbery, 2018).

4. Pools, central dispatch, capacity payments or energy-only markets?

The CEGB was centrally dispatched, and the newly restructured market design in England and Wales retained central dispatch (using the CEGB's dispatch algorithm) but created a Pool with a capacity payment. The logic of this structure was sound for a competitive market. The efficient wholesale price is the sum of the System Marginal Cost (SMC) plus a Capacity Payment, CP, where

$$CP = LoLP^*(VoLL\text{-}SMC). \qquad (1)$$

This can be rearranged to give the total price as

$$Price = (1\text{-}LoLP)^*SMC + LoLP^*VoLL. \qquad (2)$$

The first term in (2) is the energy price assuming adequate capacity, which applies a fraction (1-LoLP) of the time, while the second part is the rationing value to consumers when there is inadequate capacity, occurring a fraction LoLP of the time. The wholesale price would be efficient if, as in the All-Island SEM, generators were required to bid their marginal cost, but not in the duopoly market of the early Pool. Instead the price in (2) is determined by the System Marginal Price, possibly considerably above SMC.

---

[10] https://www.nao.org.uk/report/the-new-electricity-trading-arrangements-in-england-and-wales/

[11] https://www.elexon.co.uk/change/modifications/?show=all

The capacity payment was paid to all plant declared available the day ahead but the duopoly gamed this by withdrawing plant day ahead to increase scarcity and hence the LoLP and capacity payment, then declaring them available to collect the manipulated capacity payment (Newbery, 2005). Offer responded to this blatant manipulation by not including any unavailable plant in the calculation of LoLP for the next 8 days (even if the plant were genuinely unavailable and caused scarcity). This market manipulation strengthened Offer's resolve to abolish capacity payments, which it did in the 2001 move to the energy-only market of NETA. Under NETA owners decided whether or not to make plant available, were responsible for finding buyers, and if operating, were required to make offers and bids into the Balancing Mechanism, which the TSO would use to balance the system after gate closure.

Fig 1 shows that after the massive entry of gas-fired CCGTs and the improved availability of nuclear power, the market had a large reserve margin. This is further exemplified in fig. 4, which gives plant load (capacity) factors from 1989/90. Nuclear availability increased after privatization, but fell soon after it went into administration in 2002 before an eventual resale to EdF in 2009. Both coal and CCGT were well below their auction derating factors of 88%.[12] The balance between coal and gas output was driven by relative fuel and, later, carbon prices.

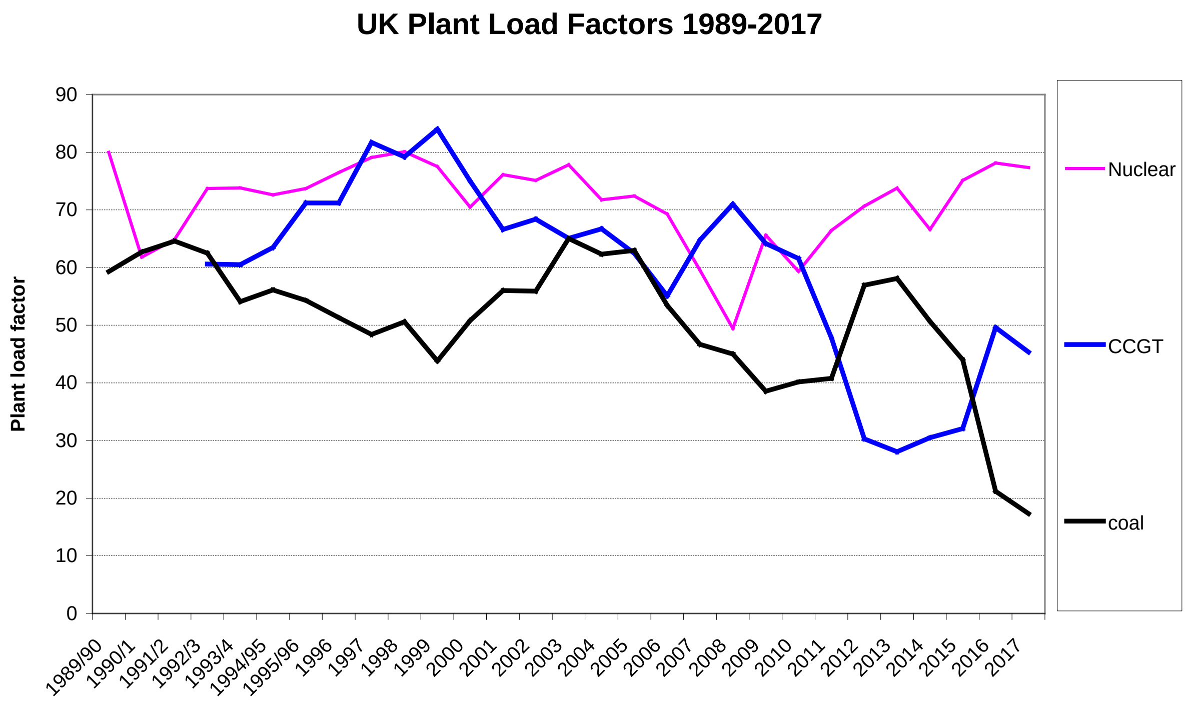

Figure 4 Plant load factors by fuel type 1997-2017
Source: DUKES, various years

Capacity payments would have been redundant in an oversupplied market, as the LoLP would remain close to zero all the time, but as the decade after NETA wore on, concerns over the life expectancy of aging coal and nuclear plant emerged, strengthened by

[12] Plant offering into the capacity auction (discussed below) is de-rated to reflect its expected availability in stress periods. Actual availability will be lower to allow for scheduled maintenance.

tightening emissions controls under first the EU *Large Combustion Plant Directive* and then the *Industrial Emissions Directive* and the perceived difficulty of life extensions for the nuclear fleet. . It was expected that some 12 GW of the older coal-fired plant (about 20% of peak demand) would close by 2015 and an additional 6.3 GW of nuclear plant by 2016. In the event nuclear plant was granted life extensions so that at the end of 2017 nuclear capacity was 9.36 GW compared to 9.91 GW at the end of 2013 (DUKES, 2018, Table 5.7).

An energy-only market might address this looming scarcity if everyone were confident that future generators would be allowed to extract scarcity value in tight periods, and that all investment in new capacity were based on the same expectations and relied on the same wholesale price. Without futures markets to lock-in such scarcity prices, and knowing the political pressures to restrain high prices, it must be doubtful that an energy-only market would deliver adequate reliability.

In addition, the UK had signed up to a challenging share of renewable energy under the EU's *Renewables Directive* (2009/28/EC).[13] Variable energy sources such as wind and solar PV require considerably more flexible controllable (effectively fossil) plant to maintain security of supply. The aging stock of large coal plant and first generation CCGTs would be inadequate, requiring new investment. However, the British electricity market was uninvestible—prices would not cover fixed costs, futures markets to signal future higher scarcity prices were lacking, and Government energy policy was in disarray, with three Energy *White Papers* published between 2003-2007. In 2008, the *UK Climate Change Act 2008*[14] was passed to provide the legal framework for ensuring that Government meets its climate change commitments. The electricity sector would bear the brunt of decarbonization, mostly through renewables (nuclear power was lagging and seen as excessively expensive). Renewables support policy oscillated between auctioned contracts in the 1990s, to a premium payment under the Renewables Obligation Scheme and small-scale Feed-in Tariffs. All (except the overly generous Feed-in Tariffs, FiTs) under-delivered relative to target. Investors, looking at the price-depressing effects of massive renewables in Germany (Hirth, 2018) and concerned that the UK Government would need to accelerate its renewables programme, were increasingly concerned about the profitability of any conventional generation investment.

The wide range of criticisms (notably from Ofgem, 2010) that the market was not likely to deliver secure, sustainable and affordable electricity finally provoked the Government to publish a *White Paper* (DECC, 2011). That set out an intellectually coherent basis for electricity market reform. After extensive consultation and Parliamentary debate, this package was finally enacted as the *Energy Act 2013*, (HoC, 2013).

The lack of a credible carbon price would be addressed by a Carbon Price Floor, enacted by HM Treasury in the Budget in March 2011. Fossil fuel used to generate electricity would be taxed (through the Carbon Price Support, CPS) to bring the minimum price of CO_2 up to £16/tonne in 2013, rising linearly to £30/tonne in 2020, and projected to rise to

[13] http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=CELEX:32009L0028:EN:NOT.
[14] https://www.legislation.gov.uk/ukpga/2008/27/contents.

£70/tonne by 2030 (all at 2009 prices).[15] As any tax (such as the CPS) could be changed at each Budget, the commitment to decarbonizing was underpinned by an Emissions Performance Standard of 450gm/kWh "at base load" (i.e. averaged over the year and effectively a cap per kW of capacity), for any new plant, set to rule out any new coal stations without Carbon Capture and Storage capability. This is discussed below in §4.2.

In order to accelerate renewables investment and to lower its cost by de-risking revenue streams, the Renewables Obligation Scheme would be phased out and replaced by a Contract-for-Difference support (described as a CfD with FiT). A CfD offers a guaranteed (and price-indexed) strike price for 15 years, with the holder receiving (or paying) the difference between a reference day-ahead market price and the strike price. In contrast to a standard CfD that specifies the volume on which the payments are made, this would apply to the actual delivery to the grid (hence it had FiT-like characteristics). The question of how best to support renewables will be addressed in §5.

The final element was a capacity payment, marking an end to the energy-only market that the EU had contemporaneously set out in the EU *Third Package.* The Target Electricity Model (European Parliament, 2009) came into effect in 2014. A capacity auction for unsupported plant (i.e. existing and new fossil generation) would determine the payment required to make new investment financeable, or to keep existing plant operating. New entry would have 15-year contracts, existing plant a one-year contract (major refurbishments could claim a 3-year contract). The case for a capacity payment is that it addresses both a "missing money" and a "missing market" problem (Newbery, 2016). The lack of sufficiently far forward futures markets to sell electricity makes revenue streams at the mercy of unstable energy policies that can undermine the market (e.g. renewables targets and support). Without adequate remuneration for the new flexibility services needed by massive renewable penetration there can be a missing money problem as well, although this terminology has normally pointed to the problems of price-capped markets

4.1 The GB Capacity Market

The Capacity Market offers 15-year Capacity Agreements for new plant provided they have connected their plant by the start of the electricity year (April-March), four years after the auction at the T-4 auction held in December. The successful plant must be available for dispatch in "stress" periods announced four hours ahead, with penalties for failures to connect or deliver. Existing plant could also bid into the same auction, and receive the same clearing price, but only for the first year, or they could wait until the T-1 auction held one year ahead of delivery. The auction was designed after careful study of the US experience, and was a pay-as-clear descending clock auction with a single price for the whole of GB (despite the presence of a potentially significant constraint on the Scottish border). The issue of the interaction of transmission constraints and capacity payments will be considered further below.

The auction was expected to clear at the net Cost of New Entry (CoNE) of £49/kWyr (based on a new CCGT and net of all the other revenue earned in energy and ancillary service

---

[15] HM Treasury, *Budget 2011*, HC 836, March 2011. The intention was to move towards a carbon price that would make it possible to claim that new nuclear power would not be subsidized.

markets). The auction demand schedule has a kink at the target capacity to procure at this level, and a cap of 1.5 x net CoNE, reaching zero 1.5 GW above target. Existing plant cannot bid higher than 0.5 x net CONE without obtaining an exemption. National Grid as System Operator was charged with determining the amount of capacity to procure needed to meet the Government's reliability standard of three hours Loss of Load Expectation (LoLE, averaged over many years),[16] and to advise the Minister who makes the final decision (see e.g. National Grid, 2014).

The relationship between the security standard and the VoLL is symmetric, in that if capacity investment decisions are based on revenues determined by (1) and the VoLL is pre-determined, then the resulting capacity will give rise to a LoLE. Zachary and Wilson (2015) show that the optimal capacity to procure is such that LoLE = net CONE/VoLL. As National Grid estimated net CONE at £49/kWyr and LoLE was required to be 3 hrs/yr, the required VoLL is £17/kWh. The Government also commissioned studies of the VoLL from London Economics (2013), a report that rather undermined the required VoLL of £17/kWh. A more plausible and lower value of VoLL would argue for a less reliable standard. The Single Electricity Market of the island of Ireland has a LoLE of 8hrs/yr and a VOLL of about €12/kWh, although a higher net CONE of €74.12/kWyr in 2017, again roughly internally consistent.[17]

The Department of Energy and Climate Change (DECC) responsible for managing EMR and the capacity auction appointed an independent Panel of Technical Experts (PTE) to comment on the SO's analysis of the amount to procure.[18] They noted (DECC, 2014) that there is a bias towards over-procurement, in that the SO stands accountable if "the lights go out" but does not pay for the capacity, while the minister wishes to avoid newspaper headlines predicting blackouts resulting from his decision. Newbery and Grubb (2015) set out the argument in more detail.

The first auction appeared to be highly successful in that it cleared at £19.40/kWyr (40% of the estimated net CoNE). The success was short-lived as the major entrant was a firm offering two large CCGTs (total 1.6 GW) failed to secure funding and shortly thereafter withdrew (leading to DECC increasing in the penalty for failure to build). The PTE had also criticized the analysis for assuming no contribution from interconnectors, despite many reports commissioned by the Government claiming that interconnectors contributed to security of supply. Arguably the failure to include their contribution more or less balanced out the exit of the CCGTs. Shortly thereafter the European Commission (DG COMP) required interconnectors to be allowed to bid into the capacity auction. Interconnectors were successful in the Early 2018/19 auction, held to remedy the exit of the CCGTs. Grubb and Newbery (2018) describe the results of the first six capacity auctions in more detail.

The other entrants were small gas or diesel reciprocating engines (average size 10 MW) connecting to the distribution networks, rather than the high tension grid. They

---

[16] Compare the former CEGB's standard of disconnecting some consumers in three winters over a 100 years, decided in 1962 (Bates and Fraser, 1974, p122). The annual LoLE is the sum of the LoLP's in each hour over the year.
[17] See www.sem-o.com/.../SEM-17-074%20ACPS%202018%20Decision%20paper%20.pdf
[18] The author was then a member of the Panel of Technical Experts but writes here in his personal capacity, drawing only on published material.

depressed the auction clearing price as they received a distorted "embedded benefit" as the avoided payment to the transmission grid of local connections. Almost all this payment was to recover the fixed costs of the transmission grid, rather than the avoided cost of actually using the network. This avoided payment of about £50/kWyr giving distribution-connected generation an effective capacity payment of £70/kWyr rather than £20/kWyr for transmission-connected plant. It took the regulator, Ofgem, three years to remove this "embedded benefit" payment.[19]

Just as the capacity auctions appeared to be bedding down as an efficient and credible way of procuring the right kind of capacity to deliver reliability and flexibility, the EU's General Court annulled the earlier EC decision to approve the GB Capacity Market on 15 November 2018.[20] In 2014 Tempus Energy complained that the auctions failed to give equal treatment to new investment to deliver demand-side response (DSR) by denying them the 15-year indexed contract offered to generation. The UK Government had little choice but to suspect all capacity payments and the 2018 December auction until the legal position is clarified, which may require DG ENER to conduct a satisfactory investigation of the treatment of DSR, or the discrimination is removed. The island of Ireland had avoided this asymmetry and to date has been allowed to continue its capacity auctions.

4.2 Climate change policy: budgets and the carbon price support

The UK has taken a lead on climate change mitigation, driven in part by dissatisfaction with the EU Emissions Trading System (ETS). The ETS seemed systemically unable to deliver an adequate, credible and durable carbon price to guide the required low-carbon and very durable power sector investments needed to meet the EU's 2050 carbon targets. In 2008, the UK Parliament passed the *Climate Change Act 2008* (HC, 2008), which sets legally binding carbon targets, the latest of which, the Fifth Carbon Budget (CCC, 2015) for 2028-32 commits the UK to reduce emissions by 57% from 1990. In the electricity sector the main instruments for delivering the target has been the Carbon Price Floor (CPF) described above, which is implemented by announcing in autumn budgets the Carbon Price Support (CPS) — an additional carbon tax on fuels burned in power stations that is added to the EU ETS Allowance price. Figure 5 shows the CPF, the EUA price, the CPS, and their sum, shown as the GB price, all in nominal prices.[21]

The carbon prices and the original planned trajectory of the CPF are shown in nominal terms, and illustrate the dramatic effect of the implementation of the *EU Market Stability Reserve* (MSR) in November 2017 (European Council, 2017). The MSR cancels surplus allowances from 2023 and makes carbon reductions more attractive, driving up the EUA price (Newbery et al., 2018). The GB carbon price for electricity is now at or above the original CPF, although how long the CPS will remain at its current, now quite high level, will

---

[19] At https://www.ofgem.gov.uk/publications-and-updates/embedded-benefits-impact-assessment-and-decision-industryproposals-cmp264-and-cmp265-change-electricity-transmission-charging-arrangements-embedded-generators

[20] https://curia.europa.eu/jcms/jcms/p1_1442288/en/

[21] The CPF oinly applies to GB, as Northern Ireland was granted an exemption to avoid distorting the Single Electricity Market of the island of Ireland.

depend both on the evolution of the EUA price and Britain's future role in EU climate change policy.

The effect of the CPS has been dramatic, moving coal plant from being the cheapest and hence running on base-load, to more costly than all but the oldest CCGTs. Figure 1 shows the resulting decline in coal, which fell from 41% in 2013 to 8% in 2018. The CPS also raises the price of electricity in GB, by roughly £15.7/MWh when coal is setting the price and by £6/MWh if CCGTs set the price, making imports more attractive. Thus if coal were at the margin 60% of the time and gas 30% of the time, the price might rise by £11/MWh, although competition from abroad might reduce that somewhat.

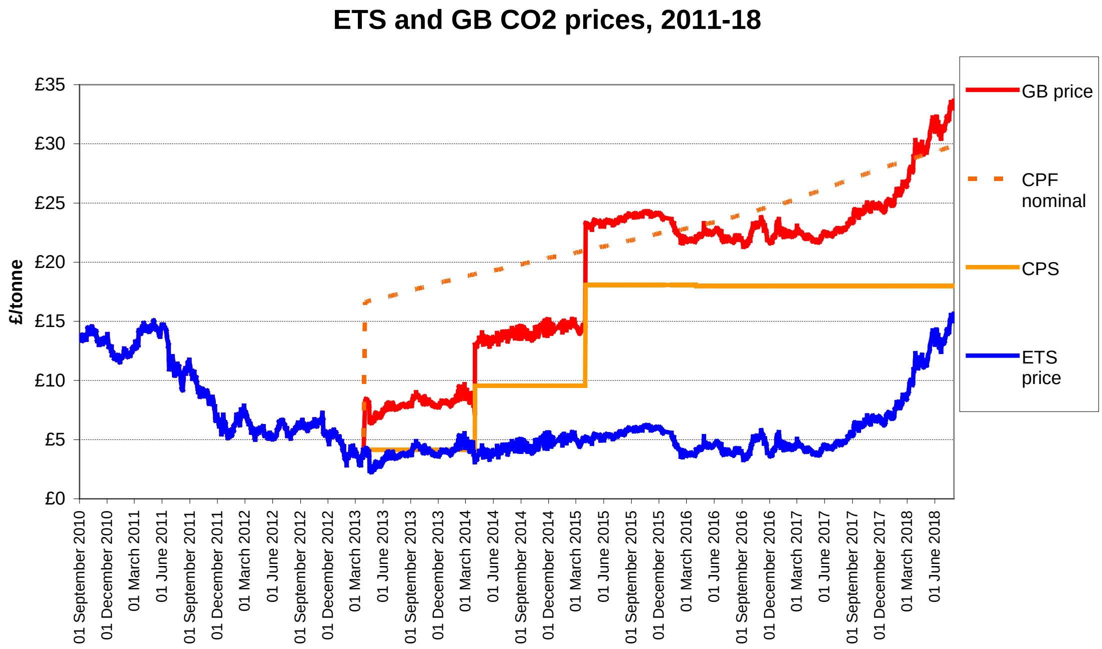

Figure 5 Evolution of the European Allowance (EUA) price for 1 tonne CO_2 and CPF
Source: EEX

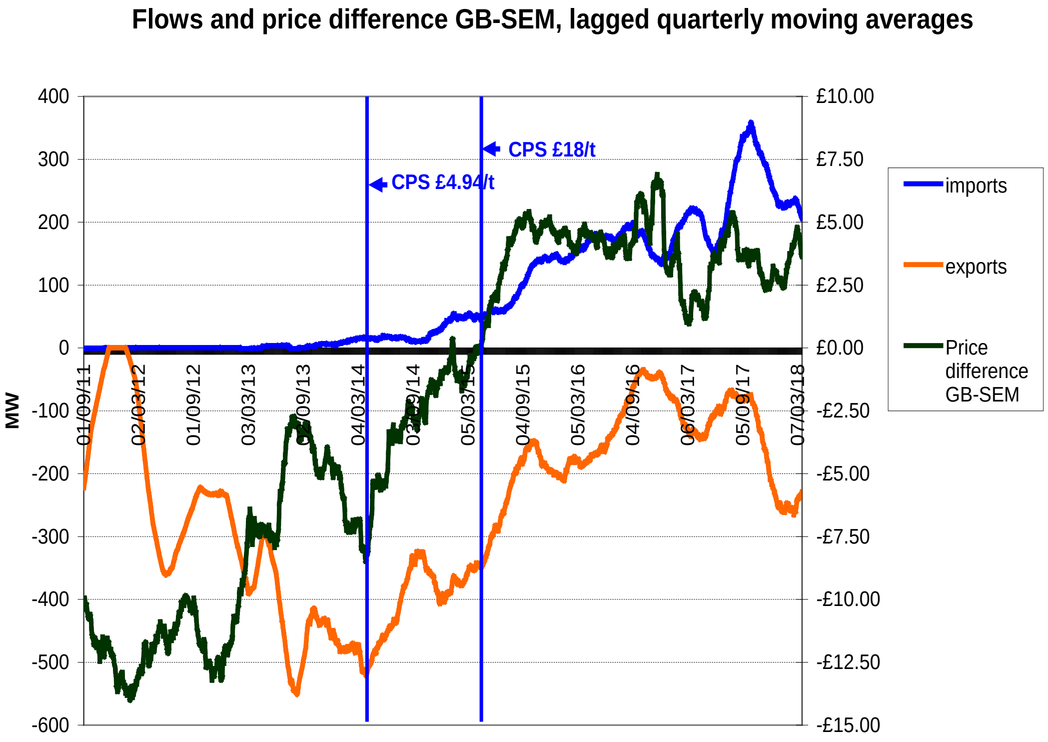

Figure 6 GB exports and imports with SEM (both Moyle and East-West interconnector)
Source: Elexon

As GB was already mostly importing electricity over its interconnectors to The Netherlands and France, the CPS merely made this even more attractive, but figure 6 shows that before the CPS reached its current level of £18/t CO_2, GB was mainly exporting to the Single Electricity Market of the island of Ireland, as their fuel prices were higher than in GB. After the March 2015 rise in the CPS, prices in GB normally exceeded those in the SEM, reducing exports and increasing imports (from their previous very low level).

Chyong, Guo and Newbery (2019) have studied the impact of the GB CPS in depth, looking at its impact in reducing emissions in the short run, as well as the emissions reductions from wind in the short and long run. They find that an extra 1 MWh of wind output resulting from a long run increase in wind capacity reduces coal output by 0.63 MWh and gas (CCGT) output by 0.37 MWh, leading to a saving of 0.68 t CO_2 when the CPS is £18/t CO_2 and fuel prices were those of 2016. If instead there had been no CPS and just the EUA price of £6/t CO_2, coal would fall by 0.32 MWh, gas by 0.67 MWh and emissions by 0.51 t CO_2 in response to 1 MWh of wind.

5 Supporting renewables: successes and remaining problems

Newbery (2016b) sets out a brief history of UK renewable electricity policy, which has come almost full circle since 1989 when the industry was privatized. At that date the Government imposed a Fossil Fuel Levy on fossil generation to finance nuclear decommissioning. The European Commission insisted that this support be made available to all zero-carbon generation, including renewables. A Non-Fossil Fuel Obligation (NFFO) was placed on electricity supply companies in the *Electricity Act 1989*, requiring them to buy a certain amount of nuclear or renewable electricity at a premium price. Support for renewables was provided through NFFO auctions for effectively Feed-in Tariffs (FiTs) (Mitchell, 2000).

The early NFFO auctions demonstrated their power of price discovery and competition in driving down costs and prices, although later the winner's curse (combined with the absence of any penalties for failure to deliver) led to under-procurement and disillusionment. The auctioned FiT contracts were replaced in the *Utilities Act 2000*, which changed the NFFO price obligation into a quantity obligation. Renewables would be given a form of Premium FiTs, called Renewables Obligation Certificates (ROCs). The amount suppliers had to procure is set annually and shortfalls are charged at a penalty rate, the revenue from which is recycled to augment the value of ROCs. The value of ROCs varies somewhat with supply and demand, although they can be banked, reducing their variability. The main problem in financing renewables is that the future price of electricity, on top of which the ROC value is added, is itself highly volatile, and hard to hedge more than a year or two ahead. In contrast to gas-fired generation, which by setting the price has a natural hedge, renewables are exposed to the full price volatility.

As noted above, the *Energy Act 2013* phased out ROCs, to be replaced by CfDs which required all but small scale renewables to be marketed at the wholesale price. They receive a top-up equal to the excess of the announced strike price over a reference market price (or, if the market price is above the strike price, the developer has to pay back the excess). This exposes renewables to imbalance risk, although they can avoid that by contracting with other utilities at a discount on the contract price.

Initially, the strike price was set administratively, but the Panel of Technical Experts in their first report (DECC, 2014) criticized the high strike prices for the 15-year renewables contracts. That, amplified by pressure from the EU Commission's concerns over State Aids, led to periodic auctions. Newbery (2016b) estimated the resulting clearing prices for on-shore wind lowered the cost of financing investments (their Weighted Average Cost of Capital or WACC) by 3% real. In the mean-time the Government had won an election with a promise to remove support for the now remarkably competitive on-shore wind (Grubb and Newbery, 2018). Subsequent auctions have excluded on-shore wind and solar PV, but auctions for off-shore wind resulted in even more dramatic cost reductions. Prices fell from an administered price of £155/MWh for the first off-shore wind farm, to £120/MWh in the Round 1 auction (East Anglia One, 714 MW, delivery 2020), and then to £57.50/MWh in Round 2 (Hornsea II, 1,386 MW, delivery 2022). Figure 7 shows the countries that have added the largest amounts of renewable generation by output since 2006, where the UK is second behind Germany.

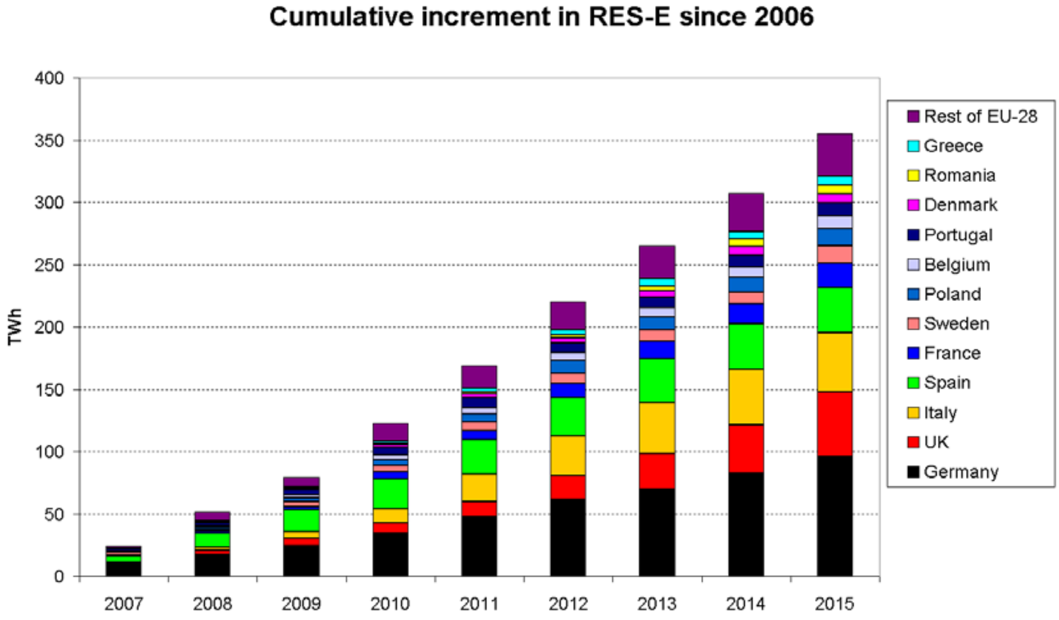

Figure 7 EU Renewable generation added since 2006
Source: Eurostat

While the auctions for all technologies, and the commitment to offshore wind in particular, have delivered remarkable cost reductions, the form of support that raises output prices has distorted location decisions. A better solution would be to run an auction for the premium to be paid for the first 20,000 (or 30,000) full operating hours (MWh/MW installed capacity). This would provide an investment subsidy (as required by the EU *Clean Energy Package*[22]) for the purchase and installation of the renewable source. It would direct support to the source of the learning spill-overs that arise from the development, manufacture and installation, and not from subsequent operation. The subsidy design requires the plant to operate successfully to secure the full subsidy, but pays for the electricity generated at its value (which might require adjustment if the carbon price is below its correct level). The present payment per MWh amplifies the apparent advantage of locating in windy (or sunny) locations, even where these incur higher transmission costs. Locating wind farms in Scotland has resulted in a huge increase in costly offshore grid investments. These offshore "bootstrap" connections might, under the original incremental cost formula for determining transmission charges, have doubled the charges for North Scotland generation (including wind) but the published tariffs have hardly changed from 2017/18 (before the Western Bootstrap was commissioned in March, 2018) to 2019/20.

Another criticism is that each EU Member State supports renewables within its territory, rather than where it could be delivered most cost-effectively. A more efficient use of resources would be for each Member State to contribute an agreed sum (e.g. as percent of GDP, per MWh consumed, or per tonne CO_2 released) to a fund. This would hold EU-wide competitive auctions (perhaps with a share designated for R&D) to deliver the learning

[22] COM/2016/0860 final at http://eur-lex.europa.eu/legal-content/EN/TXT/?qid=1481278671064&uri=CELEX:52016DC0860

benefits at least cost. It would be hard to secure political consent for this, as it touches on tax and finance, always sensitive issues. The out-turn in which Germany has led the way and made major contributions to cost-reductions could also be defended, although the cost to German consumers has been considerable. A more efficient support system might have resulted in less capacity built to meet the output target, which would have created less learning spill-over, but if these spill-overs had been recognised, it might have led to more ambitious targets and support.

6. Regulation: successes and problems

Transmission and distribution networks are natural monopolies and as such need regulation if they are to be owned by profit-maximizing private utilities (Newbery, 2000). The UK pioneered price-cap regulation with the privatization of BT, the state-owned telephone monopoly. The regulator sets a base-weighted price index for the various goods and services offered, indexed to the Retail Price Index, P_t, but subject to a productivity improvement at rate X – hence the short-hand RPI-X. Armstrong et al. (1994) describes this in more detail and provides the rationale for the price basket. Thus for product j the price p_{jt} and the resulting quantity sold, q_{jt}, at date t years after the price control at date 0 must satisfy

$$\Sigma p_{jt}q_{j0} \leq \Sigma p_{j0}q_{j0}(P_t/(P_0(1+X)^t)). \tag{3}$$

In addition, and especially important for capital-intensive network utilities, the regulator has a duty to ensure that efficiently incurred investment is properly remunerated, so that banks and shareholders are willing to finance the planned investment. This is done by starting with an initial Regulatory Asset Base or Value (RAB_0) to which is added the approved investment, I_t at date t, and deducting the depreciation, D_t, to give the updated RAB:

$$\text{RAB}_t = \text{RAB}_0 + I_t – D_t. \tag{4}$$

The regulator then determines the Weighted Average Cost of Capital, WACC, to apply to the RAB, and includes this in the revenue that the utility can recover (Capex) in addition to operating costs (Opex).

Price controls are normally for five years (a recent experiment to set an eight-year term was considered too long). The utility submits its business plan setting out its evolution of Opex and its investment plan, I_t. The regulator can (and does) benchmark the opex against comparable utilities (easy when there are 14 distribution network companies, hard when there is a single transmission company), and sets two critical parameters, P_0 and X. The initial level of the price control, P_0, will be set based on the revised business plan that the regulator finally accepts after inviting consultants to pore over it. X is set to gradually catch up with the frontier (most efficient) comparator.

With a price cap, all the cost reductions relative to expectations accrue to the utility until clawed back at the next price control, providing strong incentives to cut costs. This incentive to cut costs must not be at the expense of reduced quality or reliability, so a large part of this form of incentive regulation is to set and monitor service standards with penalties for breaches, such as interruptions to service.

This form of regulation has worked reasonably well in driving down costs and has improved reliability and quality, although utilities have earned more than the WACC and typically invested less than their business planned investment. Ajayi et al. (2018) look at 27 years of regulatory experience of the electricity networks since privatization in 1990-91. They find a total factor productivity growth in distribution networks of about 1% p.a. (higher before the financial crisis of 2008, negative after) and a worse performance for transmission (in both cases ignoring the value of the quality improvement). They suspect that low productivity reflects government objectives of increased renewables that will have raised investment needs without increasing conventional measure of network outputs.

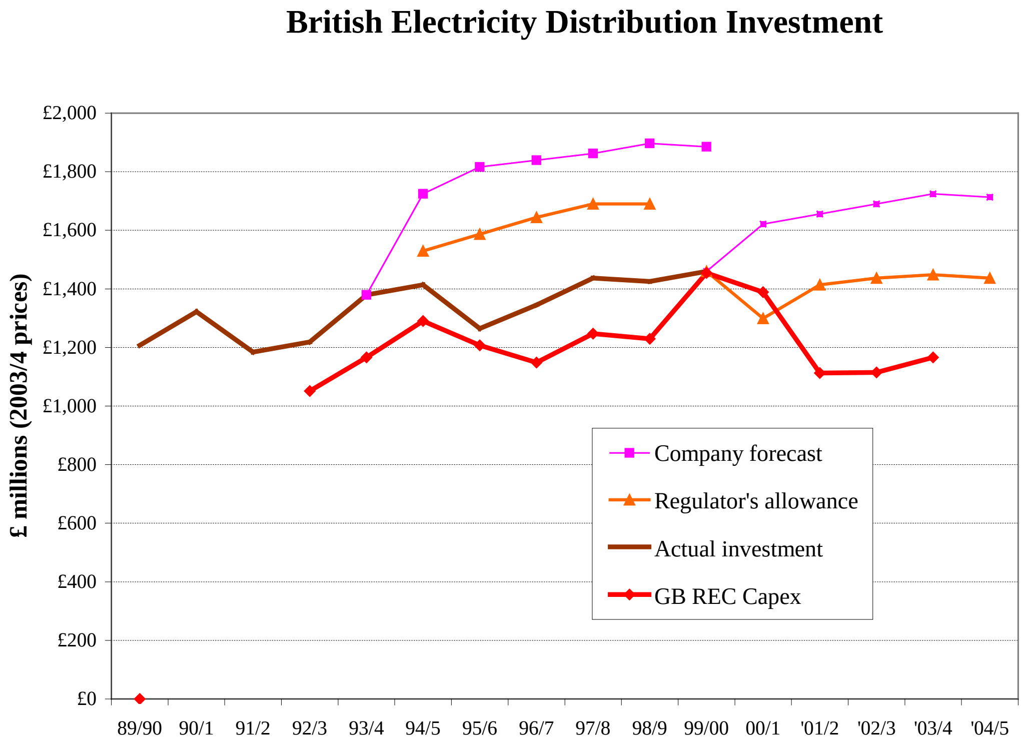

Figure 8 The game between the utility and regulator in submitting business plans

Figure 8 shows the early experience of the distribution network utilities, where they submitted forecasts of their planned investment (Pollitt and Dale, 2018, give more up-to-date investment data). The regulator revised these down, and then the utilities outperformed (or succeeded in misleading the regulator). The problem is that the main cost of networks lies in enhancing and maintaining its capital, but there is no obvious benchmark for efficient investment. It is difficult to measure the current state of the assets and what upgrades, replacements or extensions are justified in each different region. Various attempts have been made to reduce the information asymmetry between utility and regulator, and to subject investment to similar incentives as opex. In 2010, 20 years after RPI-X in the energy sector, Ofgem introduced RIIO, short for Revenue = Incentives + Innovation + Outputs. Opex and Capex are combined into Totex, and subject to incentive regulation, with innovation now playing an important role as explained in the next section.

6.1 Ofgem's Network Innovation Competitions

A regulated utility has little incentive to innovate, as if it succeeds in reducing cost, the regulator will likely reduce prices at the next price control, whereas if it fails, the cost of the innovation will be deemed unjustified and hence not compensated. To counter this, Ofgem first introduced its Low Carbon Network Fund (LCNF) for electricity network companies, and then extended this to Gas and Electricity Network Innovation Competitions. The original LCNF sum of up to £500 million for the period 1 April 2010 to 31 March 2015 was financed by a levy on consumers, and had to offer the prospect of reducing future consumer bills by more than this sum. Ofgem commissioned Pöyry (2016) to evaluate the programme.[23] Pöyry concluded that "the potential future net-benefit from the LCNF projects is significant and is estimated to range from 4.5 to 6.5 times the cost of funding the scheme." The benefits are passed on to consumers by setting future price controls for network utilities on the assumption that they will adopt proven better value solutions identified by these competitions. One of the main benefits has been to embed an innovative culture in the management of these utilities, whose professional pride depends on winning projects in the annual competition.

6.2 Tariff setting

Tariffs are important in guiding efficient location and use decisions, as transmission and distribution tariffs make up 25% of the domestic bill, compared to just 33% for the wholesale electricity cost.[24] Ideally they should be fair, efficient and cost-reflective — aims that can conflict. The variable or short-run marginal cost (SRMC) of using a network is either almost zero or a scarcity price if the network is fully used (which is rarely the case). The efficient price is as in equation (1), the sum of the SRMC and a capacity or scarcity payment that will be zero most of the time. The private owners need to receive the average cost, far above the SRMC. The shortfall in revenue is akin a tax, for which public economics lays out good design principles. Ramsey/Boiteux pricing argues that this shortfall in revenue or tax should be concentrated on the least elastic demands, e.g. through a fixed charge for access. More exactly, the mark-up on SRMC should lead to equal proportionate reductions in all uses. Peak demand pricing if there is scarcity is the first element, then charging for access or capacity rather than use follows next. The tension is that the results may not be considered fair or equitable, but this can be addressed with multi-part tariffs. For low demands, a mark-up on the energy cost can be added, which, once it reaches a level that covers a suitable fixed cost, can be replaced by a two-part tariff with a fixed and variable (energy) charge.

Domestic energy bills have a very low fixed charge and quite a high energy mark-up, which over-encourages self-production (and efficiency, that if mis-perceived, may correct a behavioural bias). Industrial and large customers pay a Triad charge, levied on the three system-peak half hours (separated by 10 days), an apparently closer approximation to an efficient charge. The main distortion is that distribution companies pay this to the transmission company at their off-take point, and until recently compensated those who supplied electricity to the distribution network at the avoided Transmission Use of System

[23] Ofgem (2016) reviews the results of, and learning from, the supported projects in detail.
[24] https://www.ofgem.gov.uk/data-portal/breakdown-electricity-bill

Charge. This massively distorted location decisions for new capacity bidding into the capacity auction, as described above. Ofgem finally reformed this "embedded benefit" in 2017.[25]

7. New Nuclear – the financing problem

Taylor (2016) charts the sorry development of British Energy under private ownership. The collapse of electricity prices precipitated by an outbreak of competition in an over-supplied market that pushed the company into insolvency in Dec 2002 when it failed to renegotiate its reprocessing contracts with the state-owned BNFL. The then Labour Government had members actively hostile to nuclear power, but others who recognized that to address climate change post-Kyoto would require active decarbonisation of electricity. Replacing aging nuclear stations with gas would raise emissions, exactly the wrong direction. After a series of reports on nuclear power from 2003-2008 (documented in Taylor, 2016), the Labour Government published a White Paper (BERR, 2008). Combined with the *Climate Change Act 2008* (HoC, 2008) this paved the way for active Government support for new nuclear plants. At the same time the Government was trying to sell British Energy, a sale finally completed in early 2009 to EdF, the (largely) state-owned French nuclear power company.

The first new nuclear project to be considered under this new regime was Hinkley Point C, which had been actively considered as the next PWR station under the CEGB in the 1980s. (The first, Sizwell B, was finally commissioned after privatization in 1995.) EdF started public consultations in 2008 and finally signed a contract with the Government in October 2013 for a stated cost of £16 bn, or £10 million/MW, a record. Taylor (2016, p167) notes that the EC state aid approval document estimated the maximum full cost with financing and contingencies as £24 billion, or 50% more. The cost was high partly as none of the same EPR design under construction were anywhere near completion and had huge cost over-runs, and partly as the Government insisted that all the construction risk lay with the private company. That is about the most expensive form of risk sharing imaginable (as the National Audit Office then made clear; NAO, 2017). The project was to be financed by a CfD lasting 35 years at a strike price of £(2013) 92.50/MWh. That might have seemed reasonable compared to renewables at the time, but was more than twice the cost of the last round of auctioned off-shore wind.

It gradually became clearer to everyone that this was not the right way to finance new nuclear power. Many took the view that it was an argument against financing any new nuclear power. No private company has ever successfully completed a nuclear power station without substantial government or regulatory financial guarantees. HPC is no exception, only unusual in the amount of risk placed on the private utility. The most recent assessment by the National Infrastructure Commission in 2018 was to not "agree support for more than one nuclear power station beyond Hinkley Point C, before 2025."[26] The argument is that by 2025

---

[25] At https://www.ofgem.gov.uk/publications-and-updates/embedded-benefits-impact-assessment-and-decision-industry-proposals-cmp264-and-cmp265-change-electricity-transmission-charging-arrangements-embedded-generators. Ofgem launched a Targeted Charging Review in Aug 2017 to examine a wider range of tariff design issues (at https://www.ofgem.gov.uk/publications-and-updates/targeted-charging-review-significant-code-review-launch).

[26] At https://www.nic.org.uk/assessment/national-infrastructure-assessment/low-cost-low-carbon/

the cost of a second (and possibly subsequent) stations should be clearer. There was no reason to rush ahead until the cheapest (full system) cost of zero carbon electricity had been more robustly identified. Since that report Toshiba has scrapped its plans for a new nuclear station in Cumbria after spending £125 million,[27] while Hitachi is considering pulling out of its new nuclear power plant at Wylfa Newydd (North Wales) although the BBC News on 15 Jan 2019 reported that it "is more likely to put it on hold rather than scrap it completely".

EdF has proposed that the next station should be an almost exact replica of HPC at Sizewell, and that it should be financed by a Regulatory Asset Based (RAB) model described above. This is standard for utilities like water and transmission companies, in which the RAB is rolled forward by adding an agreed flow of investments (and decreased by depreciation of the assets). The finance is made available in line with investment expenditure and a return on the RAB is paid to investors. This allows access to low-cost finance from pension funds. It avoids the uncertainty about when returns will be paid given the uncertain date of future commissioning, as with HPC. As with other utilities, the allowed investment would be agreed in advance with an oversight authority (e.g. the Low Carbon Contracts Company[28] that acts as counterparty to renewable CfDs). As with other utility investments, incentives in the form of cost or profit sharing with consumers of any cost over- or under-runs would reduce risk and hence lower the cost of capital. Sharing risk over a large number of consumers rather than concentrating it on one company where the asset would be a very large fraction of its market worth would reduce the cost of that risk.

The other model would be for the Government to take the construction risk on balance sheet (as with large transport projects like CrossRail or High Speed 2) and finance it a low cost public sector interest rates, as was standard for the previously nationalised energy companies. The choice between the two models depends on a balance between the public sector's lower cost of finance compared with the remarkably low rates now achieved for RAB financing of other infrastructure projects like the Thames Tideway Tunnel, and the possibility that project management and financial control are better handled by a private company with current experience of building an all-but identical project. The objection that it would add to Public Debt is spurious, as the IMF (2018) argues that it is the net wealth (assets less liabilities) that matter, not just one side of the balance sheet. Good investments strengthen, not weaken, net wealth.

8 Reflections

The British privatised electricity system is now 30 years old and a good moment to take stock of its successes and weaknesses. The premise of privatization was that private owners would invest and operate more efficiently than state-owned enterprises, and that by escaping the dead hand of ministries of finance (the Treasury in the UK case) they would have access to more investment funds, would choose more cost-effective investments, and would, through board-level and shareholder scrutiny, cease unprofitable activities sooner and respond to new opportunities more quickly. These potential benefits would have to be weighed against the

[27] See https://www.theguardian.com/environment/2018/nov/08/toshiba-uk-nuclear-power-plant-project-nu-gen-cumbria
[28] See https://www.gov.uk/government/publications/contracts-for-difference/contract-for-difference

increased cost of private capital, and a possible loss of concern over distributional issues and environmental impacts, unless motivated to take them into account.

Avner Offer (2018) has pointed out that the private sector is well placed to invest where the credit time horizon is attractive to private lenders, defined as the time to pay back the loan. Roughly speaking, private finance is twice the cost of public finance, so the private pay-back period (simply computed) is half that of the government. Government guarantees or their regulatory equivalent (such as the US model of rate-of-return regulation underpinned by a Constitutionally backed rule of law) can offer reassurances, lower the cost of capital and extend this credit horizon. Offer points out that as telecoms land lines may last a century they required state-ownership or regulated monopolies to undertake the investment. Mobile telephony has equipment that may be replaced in less than a decade, lending itself to private ownership.

The British electricity supply industry in 1989 was well placed to reap many of the benefits of private ownership, and initially, to avoid many of the downside costs.[29] Spare capacity avoided the need for costly durable generating capacity and the risk of an inappropriate credit time horizon. The arrival of cheap CCGTs of modest scale, rapid delivery and high efficiency, at a time of falling gas prices, made any such investments lower risk. Even then, such investments needed long-term PPA contracts and a captive franchise market. The more capital-intensive and durable networks were assured of financeability through licence conditions, obligations on the regulator and a credible dispute resolution process. The RAB form of asset regulation arguably improved on the US model of utility regulation (Gilbert and Newbery, 1994). Distributional concerns emerged, and were, with varying degrees of success, met with licence conditions on utilities, low (and distorting) rates of VAT on energy, political pressure on the regulator, Competition and Market Authority inquiries (CMA, 2016), and price caps. Environmental concerns were met with increasingly stringent emissions standards on pollutants, the ETS, various EU Directives, and in GB, the Carbon Price Support.

Problems emerged when new capital-intensive generation investment was needed, both to meet carbon and renewables targets, and to maintain reliability. The ideology of the market initially led to auctions for renewables that were remarkably effective at driving down costs, less so at delivering adequate volumes. The shift to the Renewables Obligation pulled through more delivery but at a high cost of finance. It took over 20 years to learn from experience elsewhere that long-term contracts at assured off-take prices would lower the cost of capital and with it the delivered cost of renewable electricity.

Nuclear Power and Carbon Capture and Storage (CCS) demonstrated the force of Offer's credit time horizon. No nuclear power station has ever been constructed without strong and credible underwriting from either the government or a utility empowered to pass the cost through to final consumers. Even that model came off the rails in the US after the oil shocks of the 1970s raised inflation and electricity costs. Rate reviews are needed when utility rates need raising. That requires utility commissions to scrutinise costs and investment plans to ensure they are "just and reasonable". The Washington Public Power Supply System, aptly named Whoops, had started on one nuclear plant and had plans for four more, with two

[29] Pollitt (2012) discusses the wider lessons from electricity liberalisation.

units starting in 1977. WPPSS has the right to issue tax-favoured municipal bonds to finance investments without voter approval, but a voter initiative in 1981 denied WPPSS the right to issue more bonds. Construction was suspended and eventually only the first reactor was ever completed.[30]

In Britain, as described above, Hinkley Point C has staggered on since before privatization, and only (just) secured its Final Investment Decision after one of the most costly financing arrangements with government guarantees was struck. Given a possible construction period of ten years and a subsequent life of 60 years, followed by possibly centuries of waste management, nuclear power busts Offer's credit time horizon comprehensively. CCS has had an even worse experience, with over a decade of unfulfilled promises to deliver a commercial-scale plant. Even conventional CCGTs now need 15-year capacity payments to encourage investment, so that to a greater or lesser extent all new generation now receives under-written guarantees by the Government.

Critics (e.g. Darwell, 2015) argue that this reflects a betrayal of the original aims of privatization, while realists (and very belatedly and to a limited extent, the Government) argue that durable essential infrastructure like electricity needs access to low-cost finance that only government-backed or guaranteed finance can assure.[31] Perhaps the most useful lesson from privatizing utilities is that the UK has evolved a system of regulating at least part of the infrastructure (the natural monopoly pipes and wires) that works reasonably well and has delivered high levels of investment at modest rates of interest. It would be encouraging to think that the UK can continue to learn how better to finance the necessary capital-intensive zero carbon energy to meet our climate goals in a timely fashion.

[30] https://en.wikipedia.org/wiki/WNP-3_and_WNP-5

[31] One of the major failings of the post-Thatcher civil service is its declining ability to attract and retain the brightest and best, coupled with excessive rates of staff turnover that makes learning from the past and reaching informed financial decisions increasingly difficult (Sasse and Norris, 2019).

References

Ajayi, V., K. Anaya and M. Pollitt, 2018. *Productivity growth in electricity and gas networks since 1990: Report prepared for the Office of Gas and Electricity Markets (OFGEM),* at https://www.ofgem.gov.uk/system/files/docs/2019/01/ofgem_productivity_report_dec_2018_1.pdf

Allaz, B. and Vila, J-L., 1993. Cournot competition, forward markets and efficiency, *J. Ec. Theory* 59, 1-16

Armstrong, M., S. Cowan and J. Vickers, 1994. *Regulatory Reform - Economic Analysis and British Experience*, Cambridge: MIT Press

Bates, R., Fraser, N., 1974. *Investment Decisions in the Nationalised Fuel Industries*, Cambridge, CUP.

BEIS, (2017). *Historical electricity data: 1920 to 2016*. Available at https://www.gov.uk/government/statistical-data-sets/historical-electricity-data-1920-to-2011 .

BERR, 2008. *Meeting the Energy Challenge: A white paper on nuclear power*. Cm 7296 at https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/228944/7296.pdf

Boiteux, M. (1949). La Tarification des Demandes en Pointe: Application de la Théorie de la Vente au Côut Marginal, *Revue Générale de l'Electricité*.

Bower, J. (2002). Why did electricity prices fall in England and Wales? Market Mechanism or Market Structure? OIES WP El02, at https://www.oxfordenergy.org/publications/why-did-electricity-prices-fall-in-england-and-wales-market-mechanism-or-market-structure/

CCC, 2015. *Fifth Carbon Budget*. Committee on Climate Change, at https://www.theccc.org.uk/publication/the-fifth-carbon-budget-the-next-step-towards-a-low-carbon-economy/

CMA, 2016. *Energy market investigation*, Competition and Markets Authority Final Report, 24 June, at https://assets.publishing.service.gov.uk/media/5773de34e5274a0da3000113/final-report-energy-market-investigation.pdf

Darwell, R., 2015. *Central Planning with Market Features: how renewable subsidies destroyed the UK electricity market*, Centre for Policy Studies, at http://euanmearns.com/renewable-energy-the-most-expensive-policy-disaster-in-modern-british-history/

DECC, (2011). *Planning our electric future: a White Paper for secure, affordable and low-carbon electricity*, at http://www.decc.gov.uk/en/content/cms/legislation/white_papers/emr_wp_2011/emr_wp_2011.aspx .

DECC (2013). Annex F: EMR Panel of Technical Experts Final Report for DECC. July, at https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/223656/emr_consultation_annex_f.pdf.

DECC, (2014). *EMR Panel of Technical Experts Final Report on National Grid's Electricity Capacity Report*, at https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/252743/Capacity_Market_Impact_Assessment_Oct_2013.pdf

Domah, P. and Pollitt, M.G. (2001) "Restructuring and privatisation of electricity distribution and supply businesses in England and Wales: a social cost-benefit analysis." *Fiscal Studies*, 22(1): 107-146 (DOI: 10.1111/j.1475-5890.2001.tb00036.x)

European Parliament, (2009). *Directive 2009/72/EC* of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC at https://eur-lex.europa.eu/legal-content/EN/ALL/?uri=CELEX%3A32009L0072 .

European Council (2017). Reform of the EU emissions trading system – Council endorses deal with Parliament, Press Release, 22 November.

Evans, J. and R.J. Green, (2003). Why did electricity prices fall after 1998? CMI WP26, available at https://ideas.repec.org/p/ecj/ac2003/92.html

Gilbert, R.J. and D.M. Newbery (1994) 'The Dynamic Efficiency of Regulatory Constitutions', *Rand Journal of Economics*, **25**(4), 538-54

Giulietti, M., L. Grossi and M. Waterson, 2010. Price transmission in the UK electricity market: Was NETA beneficial?, *Energy Economics*, **32**(4), 1165-1174.
Green, R.J. and Newbery, D.M., 1992. Competition in the British Electricity Spot Market. *J. Pol. Econ*. 100(5), 929-53. http://www.jstor.org/stable/2138629
Grubb, M. and D. Newbery, 2018. UK Electricity Market Reform and the Energy Transition: Emerging Lessons. *The Energy Journal*. Earlier version published as MIT CEEPR WP 2018-004 and EPRG WP 1817 at https://www.eprg.group.cam.ac.uk/wp-content/uploads/2018/06/1817-Text.pdf
Chyong, K., B. Guo and D. Newbery, 2019. The impact of a Carbon Tax on the CO_2 emissions reduction of wind. EPRG WP 1904 at https://www.eprg.group.cam.ac.uk/category/working-papers-2019/
DUKES, various years, *Digest of UK Energy Statistics*, available at https://www.gov.uk/government/collections/digest-of-uk-energy-statistics-dukes
Henney, A. (1987). Privatise Power: How to restructure the Electricity Supply Industry, Policy Journals, May.
Henney, A. (1994). *A study of the privatisation of the Electricity Supply Industry in England and Wales*. EEE Ltd.
Hirth, L., (2018). What cause the drop in European electricity prices? A factor decomposition analysis. *The Energy Journal*, 19(1), 132-157
HMT, 2011. *Budget 2011*, Stationary Office, HC 836 at http://webarchive.nationalarchives.gov.uk/20130105112918/http://cdn.hm-treasury.gov.uk/2011budget_complete.pdf
HoC, 2008. *Climate Change Act 2008*, at http://www.legislation.gov.uk/ukpga/2008/27/contents
HoC, 2013. *Energy Act 2013*, 2013.c.32, at http://www.legislation.gov.uk/ukpga/2013/32/contents/enacted/data.htm
IMF, 2018. Managing Public Wealth, *Fiscal Monitor* October 2018 at https://www.imf.org/en/Publications/FM/Issues/2018/10/04/fiscal-monitor-october-2018
London Economics, 2013. *The Value of Lost Load VoLL for Electricity in Great Britain; Final report for OFGEM and DECC*, July, at https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/224028/value_lost_load_electricty_gb.pdf
Meek, R.L. (1968). The New Bulk Supply Tariff for Electricity, *The Economic Journal*, 78 (309), 43-66
Mitchell, C. (2000), The England and Wales Non-Fossil Fuel Obligation: History And Lessons, *Annu. Rev. Energy Environ*. 25: 285–312.
NAO, 2017. *Hinkley Point C*, HC: 40, 2017-18, at https://www.nao.org.uk/report/hinkley-point-c/
National Grid (2014). *Electricity Capacity Report*, at http://www2.nationalgrid.com/UK/Our%20company/Electricity/Market%20Reform/Announcements/June%202014%20Auction%20Guidelines%20publication/
Newbery, D. M., 1995. Power Markets and Market Power. *The Energy Journal*, 163, 41-66
Newbery, D. M. (1998) 'The Regulator's Review of the English Electricity Pool', *Utilities Policy*, **7**(3), 129-41 http://ideas.repec.org/a/eee/juipol/v7y1998i3p129-141.html
Newbery, D.M. (2000), *Privatization, Restructuring and Regulation of Network Utilities*, (The Walras-Pareto Lectures, 1995), MIT Press, 2000, ISBN 0-262-14068-3
Newbery, D.M., 2005. Electricity liberalisation in Britain: the quest for a satisfactory wholesale market design. *The Energy Journal*, Special Issue on European Electricity Liberalisation, ed. D Newbery, 43-70 at http://www.iaee.org/en/publications/speciali.aspx
Newbery, D.M., 2012. Reforming Competitive Electricity Markets to Meet Environmental Targets. *Econ. Energy & Envir. Pol*. 1(1), 69-82.
Newbery, D.M. 2016a. Missing Money and Missing Markets: Reliability, Capacity Auctions and Interconnectors, *Energy Policy*, 94, 401–410. Doi: http://dx.doi.org/10.1016/j.enpol.2015.10.028
Newbery, D.M., 2016b. Towards a green energy economy? The EU Energy Union's transition to a low-carbon zero subsidy electricity system - lessons from the UK's Electricity Market

Reform, *Applied Energy*, 179, 1321–1330. Doi: http://dx.doi.org/10.1016/j.apenergy.2016.01.046
Newbery, D.M., 2017. Tales of Two Islands - Lessons for EU Energy Policy from Electricity Market Reforms in Britain and Ireland, *Energy Policy*, **105**, 597–607 available online at http://doi.org/10.1016/j.enpol.2016.10.015
Newbery, D.M. and M.G. Pollitt (1997) 'The Restructuring and Privatisation of the CEGB- Was it worth it', *Journal of Industrial Economics*, XLV (3), 269-303 http://www.jstor.org/stable/2950471
Newbery, D.M. and R. Green (1996) 'Regulation, public ownership and privatisation of the English electricity industry', ch 2, 25-81 in Richard J Gilbert and Edward P Kahn (eds) *International Comparisons of Electricity Regulation*, New York: Cambridge University Press, 1996 ISBN: 0-521-49590-3
Newbery, D., D. Reiner and R. Ritz, (2018). The political economy of a carbon price floor for power generation. *The Energy Journal* (in press). Also EPRG WP 1816 at https://www.eprg.group.cam.ac.uk/eprg-working-paper-1816/ https://www.ofwat.gov.uk/consultation/consultation-on-the-regulatory-framework-for-the-infrastructure-provider-that-will-deliver-the-thames-tideway-tunnel-project/pap_tec20141007draftguidance/
Offer, A., 2018. Patient and impatient capital: time horizons as market boundaries, Oxford Discussion Papers in Economic and Social History, Number 165, August 2018
Ofgem, (2010). *Project Discovery: Options for delivering secure and sustainable energy supplies*. February, at https://www.ofgem.gov.uk/ofgem-publications/40354/projectdiscoveryfebcondocfinal.pdf .
Ofgem, 2016. *EA technology's Summary of the Low Carbon Network Fund Learning* at https://www.ofgem.gov.uk/publications-and-updates/ea-technology-s-summary-low-carbon-network-fund-learning
Pollitt, M.G. (1998) `The restructuring and privatization of the Electricity Supply Industry in Scotland', Cambridge: mimeo, June
Pollitt, M.G., 2012. The role of policy in energy transitions: Lessons from the energy liberalisation era, *Energy Policy*. 50, 128–137.
Pollitt, M.G. and L. Dale, 2018. Restructuring the Chinese Electricity Supply Sector - How industrial electricity prices are determined in a liberalized power market: lessons from Great Britain, EPRG Working Paper 1839 at https://www.eprg.group.cam.ac.uk/wp-content/uploads/2018/11/1839-Text.pdf
Pőyry, 2016. *An Independent Evaluation of the LCNF: A report to Ofgem*, at http://www.poyry.co.uk/ofgem-publishes-poyrys-independent-evaluation-low-carbon-network-fund
Sass, T, and Norris, E., 2019. *Moving On - The costs of high staff turnover in the civil service*. Institute for Government, at https://www.instituteforgovernment.org.uk/publications/moving-on-staff-turnover-civil-service?inf_contact_key=8846f4a954b5997853d299be93499e758ecc59848a11ab5d044ad912ef17bc52
Sweeting, A., 2007. Market Power in the England and Wales Wholesale Electricity Market 1995–2000. *The Econ. J*., 117: 654–685. doi: http://dx.doi.org/10.1111/j.1468-0297.2007.02045
Taylor, S. (2007) *Privatization and financial collapse in the nuclear industry - the origins and causes of the British Energy crisis of 2002*. London: Routledge.
Taylor, S., 2016. *The Fall and Rise of Nuclear Power in Britain; A history.* UIT Cambridge
Zachary, S. and A. Wilson, 2015. Robustness of reliability measures, mimeo, Durham University, Dec 19.

Source of figures
Fig 1: Elec\Dukes\DUKES_5.1_2017 to update
Fig 2: Elec\England & Wales Power stations (2005)
Fig 3: Elec\NETA\RGPool to update
Fig 4: Elec\NETA\Gen\DUKES_5.10
Fig. 5 Environ\EUA price
Fig.6: Interconnectors\import
Fig. 7: Elec\Europe\RES generation
Fig. 8: Elec\Retail\GBRECInvest