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Regulation of access, fees, and investment planning of transmission in Great Britain

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Reference Details

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Keywords   transmission fees, regulation, off-shore wind, LMP

JEL Classification D02, D44; H54; L51, L94, Q42;

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[1] Draft chapter for *Handbook on Electricity Regulation*, eds. P Joskow, M. Pollitt and J-M Glachant

Regulation of access, fees, and investment planning of transmission in Great Britain[1]

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4   Introduction and background

Until the wave of liberalization in the 1990s, almost all electricity utilities were vertically integrated with generation and transmission in one usually state-owned or tightly regulated company. As such, planning investment could take an integrated view of locating generation and building the network to minimize system cost. This integration was made easier as generation was typically in large plants located near fuel sources (coal mines or ports) and adequate cooling water. Pricing was mainly concerned to set prices to distribution networks (in Britain, regionally separate companies) that were typically responsible for setting tariffs to final consumers.

Liberalization relied upon legally (and usually ownership) separation of the potentially competitive generation sector from the natural monopoly networks, which would need regulation to deliver efficient pricing. Previously centrally dispatched generation would now be required to sell to the wholesale market, which had to be designed to ensure reliable operation, while the transmission company now had to devise suitable rules, tariffs or charges to decentralize investment location and real-time dispatch decisions. This happened just as more footloose gas-fired smaller generators became cost-competitive. The previous link to old fuel sources was further weakened by initially modest investment in quite differently located renewable generation (wind and solar PV). From 2002, when the Renewables Obligation scheme was introduced, and more so as renewables costs fell and the support scheme was made less risky in 2014, renewable electricity accelerated to become the dominant form of new generation.

Great Britain provides an interesting case study of how these various transitions from integrated state-ownership to unbundled transmission and system operation, through gas entry and then the massive commitment to decarbonization, and the challenges they set for devising efficient market designs and transmission charging. This chapter sets out a brief history of these key transitions, before discussing how these challenges have been and might better be met.

2.   A brief history of transmission in Great Britain

The electricity supply industry in the UK consists of three separate ownership structures reflecting the different jurisdictions. Northern Ireland (NI) is separated by sea from Great Britain (GB), and now part of the Single Electricity Market of the island of Ireland under EU jurisdiction. Transmission and distribution are regulated by the NI Utility Regulator and subject to UK competition law. Scotland has considerable devolved powers so "Scottish

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Ministers are responsible for approving applications to build, operate or modify onshore electricity generating stations with capacities exceeding 50 megawatts, as well as all applications to install overhead power lines…"[3] Scotland has two transmission companies under separate ownership, although the wholesale market is now managed by the GB Electricity System Operator (ESO). England and Wales (E&W) have always had their own transmission company. Distribution companies are regional, with two in Scotland covering the same areas as the two Scottish transmission companies.

Figure 1 shows the evolution of regulated actual network expenditure since privatization, data for which in Scotland is available from 1993/4.
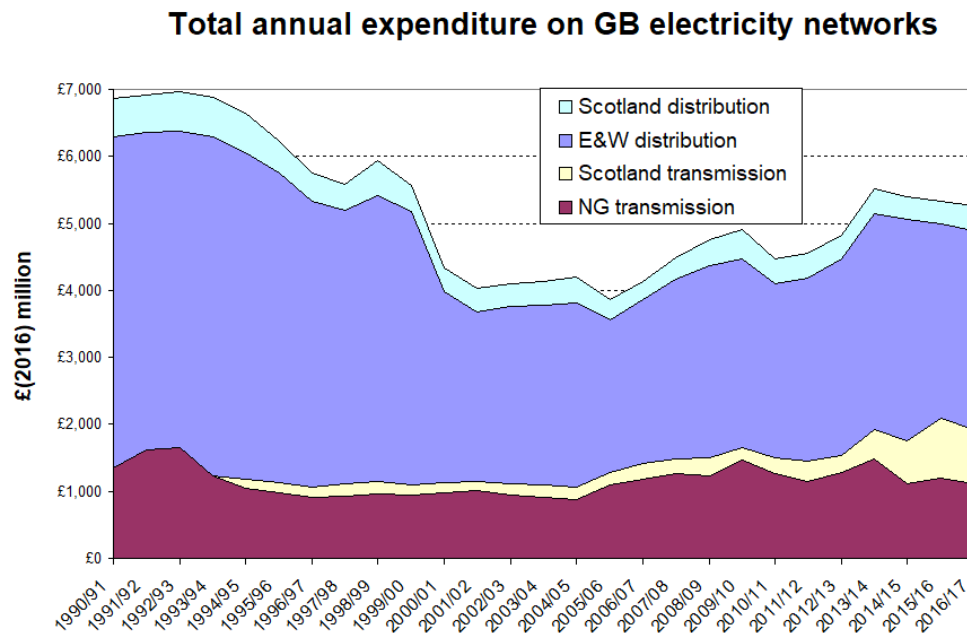

Total annual expenditure on GB electricity networks

Figure 1 The evolution of regulated expenditure (Totex) in GB network companies[4]

As a rough measure of their relative sizes, Scottish distribution companies account for about 10% and E&W the remaining 90% of total GB distribution capital and operating expenditure. Scottish transmission companies account for 20% and E&W 80% of total GB transmission expenditure. GB transmission accounted for 28% of total network expenditure (from 1994/5). This chapter concentrates on transmission in England and Wales (E&W) since privatization in 1990.

The relevant historical milestones for transmission in E&W start with the creation of the Central Electricity Board in 1926, which established the first synchronized electricity grid, gradually linking different regions until in 1938 the whole country was synchronized under the National Grid, operating at 50hz and 132kV. In 1947 the industry was nationalized and after several name changes became the Central Electricity Generating Board (CEGB, 1958-1990). The CEGB was structured into transmission and system operation (National Grid, initially operating at 275kV), and a single company with all generation. Twelve Area

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[3] https://www.gov.scot/policies/energy-infrastructure/energy-consents/
[4] The data was collected by Michael Pollitt and his colleagues from a variety of source, see Ajayi et al. (2022) data appendix

Boards managed distribution and supply regionally. Scotland had two vertically integrated companies – the South of Scotland Electricity Board (1955-91) and the North of Scotland Hydro-Electric Board (1943-1990), both integrating distribution and supply.

Under the CEGB demand grew at a remarkably steady rate until the oil shocks of the 1970s at just over 7% p.a., with demand doubling every 10 years. Rapid demand growth stimulated a move to larger power stations and from 1965 transmission was upgraded from 275kV to 440kV.

2.1 Privatization and restructuring

In 1990 the non-nuclear assets of the CEGB were privatized as an unbundled set of companies. The two Scottish companies were privatized as unrestructured vertically integrated companies a year later. The guiding philosophy of the restructuring was that the transmission and distribution networks as natural monopolies would need to be regulated. Generation and retailing were potentially competitive and should therefore be largely left to the market under general competition law. National Grid with its large pumped storage assets was placed under the shared ownership of the 12 Regional Electricity Companies, the successors to the Area Boards. In 1994 the two large pumped storage schemes were sold, and in 1995 National Grid was floated on the stock exchange. As with other nationalized utilities the Government's aim was to encourage the public to buy shares up to a maximum amount at a discounted price.

The supply (retailing) business was separated from the Distribution Network Owners (DNOs) spun out of the Regional Electricity Companies. Supply competition was gradually expanded down to the household level by 1999, with new electricity supply companies entering (and subsequently many exiting). Competition among the increasingly fragmented generators encouraged many of them to integrate forward into supply business to become the "Big Six" vertically integrated supply companies.[5]

2.1   From the Electricity Pool to BETTA

National Grid as Transmission System Operator (TSO) centrally dispatched all (above 50MW) power stations whose power was sold in the Electricity Pool at the System Marginal (bid) Price. In 2001 the Pool was replaced by the New Electricity Trading Arrangements (NETA) with self-dispatch, leaving the TSO to operate the real time "market" (the Balancing Mechanism).[6] Scotland was separately dispatched with trade over the Scottish border requiring auctioned access to the two links (Bell, 2009).

In 2004 Scottish System operation was replaced by National Grid ESO under the British Electricity Trading and Transmission Arrangements (BETTA). NGESO took responsibility for System Operation of the entire GB system. Scotland had previously had to secure capacity across the interconnectors to England, and as an export region this should have resulted in lower wholesale prices in Scotland. However, as vertically integrated companies with considerable market power, Ofgem (the electricity regulator) imposed a price cap on the Scottish wholesale price linked to the Pool price. After NETA and the end of the Pool "the cap will be an appropriate half hourly power exchange price plus NGC's BSUoS

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[5] British Gas, EDF Energy, E. ON, npower, ScottishPower and SSE.
[6] see NAO (2003)

charge less 1.5 per cent."[7] BETTA also meant that Scottish renewable electricity was now free to sell to any GB off-taker, not just to the Scottish incumbents, while Scottish consumers could at last enjoy the lower transmission prices for Load once the market was integrated. This was important as before privatization Scottish domestic prices were substantially lower that English domestic prices, but after privatization and no access to the E&W Pool Scottish domestic prices rose above E&W domestic prices.[8]

Once the two nations were integrated into a single price zone, the interconnector constraints on flows had to be managed in the Balancing Mechanism by compensating Scottish generators that could not be accommodated and replacing them by higher priced English generators. NGET (2009) noted that "the introduction of BETTA in 2005 resulted in an increase in constraint costs as all market participants were exposed to National Grid resolving system limitations that occur within the Scottish transmission system and across the circuits that connect Scotland to England and Wales (E&W) (known as the Cheviot or B6 boundary). NGET (2010, Fig. 4) showed that constraint costs in E&W and Scotland before BETTA were less than £50 million/yr. but jumped to £250 m./yr. by 2008/9. While much of this was planned outages for reinforcement needed to integrate the markets, "it can be seen that constraint costs in 2008/09 were considerably higher than in previous years driven by high volumes of constraints across the Cheviot boundary as a result of extended outages and high generation output." (NGET, 2009, Fig. 5 and after). This rapid increase in constraint costs was exacerbated by the "connect and manage" regime discussed below. This was designed to accelerate entry of new mainly wind generators, for whom Scotland was the most attractive location.

In 2019 National Grid, the parent company, split off the Electricity System Operator (NGESO) and Electricity Transmission Owner (NGET). It is expected (as of 2023) that the ESO will become a state-owned independent Future System Operator (FSO), possibly with enhanced network planning powers (and a different name). In the UK National Grid Company also owns interconnectors in the legally separated subsidiary, National Grid Ventures.

3. Network regulation

Britain introduced a system of incentive regulation for British Telecom in 1984 to avoid the incentive to gold-plate investment of the US rate-of-return model (Averch and Johnson, 1962). The aim was to mimic the incentive effects of a competitive market where other firms set the price, encouraging each firm to compete on quality, only able to increase profits by cutting costs and innovating. This was to be achieved by providing a contract for 25 years and setting a price cap (originally indexed to the Retail Price Index, hence RPI) and an efficiency target (X, hence RPI-X). At each Periodic Review (normally at five year intervals) the cap would be revisited to see whether the previous regulatory agreement remained valid (i.e. not above that of a competitive efficient firm), and if not to reset the next period's initial price level (P_0) and/or the efficiency factor, X. This works well for an industry with many

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[7] https://www.ofgem.gov.uk/sites/default/files/docs/2001/03/2001---scottish-administered-pricing-arrangements---from-1-april-2001-14-03_0.pdf
[8] https://www.ofgem.gov.uk/sites/default/files/docs/2002/04/1105-factsheet0702_15april_0.pdf

similar companies against which each can be benchmarked. Where the firm offers a basket of goods and services (e.g. telecoms offering local and long-distance calls and data services) the price cap is applied to a weighted average of prices in the basket. For efficiency the weights are the base year quantities (see Armstrong et al.,1994 for more details on its efficiency properties).

In the case of an asset-heavy industry like transmission the major part of the continuing cost is the weighted average cost of capital, WACC, paid out to debt holders and equity owners. In setting the amount of revenue that NGET will be allowed to recover from its tariffs, the regulator Ofgem starts with the opening Regulatory Asset Value, RAV, R_0, determines the appropriate WACC,[9] r, agrees the amount of capital expenditure (Capex) allowed in the determination, I,[10] and calculates the depreciation on the opening RAV, D. The closing RAV is $R_1 = R_0 + I - D$.[11] This is carried forward to the next period inflated by the appropriate price index (originally the RPI, but in later years the more accurate Consumer Price Index, CPI).

The principle of incentive regulation is to mimic a competitive outcome, but setting the prices and ensuring delivery of the efficient outcomes is subject to information asymmetry and credibility – NGET knows more about its costs and operations than Ofgem and may be tempted to inflate its cost forecasts, but Ofgem could retrospectively deem some investments inappropriate. Benchmarking avoids this problem where there are many comparable companies to estimate efficient costs, but country-wide transmission has no obvious comparators. In addition, it is asset-heavy with relatively low operating costs, making RPI-X more like rate-of-return regulation with its incentive to over-invest, although with the incentive to make efficiency savings once the price control is agreed.[12]

Under the original RPI-X regulation the allowed revenue will be the sum of the gross return on capital, $G = rR_0 + D$, and the allowed operating expenditure (Opex). In contrast, the total controllable expenditure (Totex, shown in figure 1) is the sum of Capex, I, and Opex. From 2013 Ofgem replaced the simple RPI-X approach by RIIO (**R**evenue using **I**ncentives to deliver **I**nnovation and **O**utputs) to address the bias towards asset-heavy solutions. As Vogelsang (2006) argued, the need to combine long-term commitment with incentives to innovate makes profit sharing superior to pure price-cap regulation. Gilbert and Newbery

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[9] Determined from the capital asset pricing model as the weighted average of the expected cost of debt and the required return to equity. There are complex rules to deal with taxation, which have been variously dealt with by using a pre-tax return on equity or using a plain vanilla WAC which abstracts from tax, but adds the amount needed to meet corporation tax back to the operating cost – see Oxera's useful note at https://www.oxera.com/insights/agenda/articles/which-wacc-when-a-cost-of-capital-puzzle-revisited/

[10] Expenditure on investment in long-lived network assets, such as underground cables, overhead electricity lines and substations.

[11] The particular form of the depreciation formula (e.g. straight line or declining balance) is immaterial, as shown in Newbery (1997).

[12] Newbery (2000) compares rate-of-return regulation with incentive regulation. Under RoR regulation, in periods of technical progress and low inflation when consumers are content with existing rates, there is no pressure to demand a rate review to reset rates and hence an incentive for the utility to cut costs and retain profits, as under RPI-X regulation. Information asymmetries under RPI-X are reduced by active consumer reactions (as they will have to pay the higher cost of excess investment) as well as forensic auditing of the submitted business case.

(1994) argued that in such capital intensive industries, rate-of-return regulation combined with a "used and useful" criterion provides the necessary commitment for efficient investment.

RIIO starts from the same building blocks as RPI-X but then adds incentives and penalties, so the allowed revenue makes more assumptions, and the outputs now include considerable sums to pay for innovation (awarded through Network Innovation Competitions and other smaller allowances). From 2013 the outputs will therefore include these additional elements. Figure 2 shows the evolution of the component parts of Totex and the allowed revenue, with the caution that there are periodic changes in their methodology, so that pre-2001 data may not be comparable to post-2001 data.

The difference between allowed revenue and Totex is the return on capital plus depreciation *less* investment (*rR+D - I*). The gross return on and to capital is considerably higher than investment, reflecting the huge weight of the returns to existing assets compared to current investment, as shown in Figure 2. This is not surprising as the original length of NGET's transmission was 14,505 km. in 2000 and only increased by 324 km. (2.2%) over the following 16 years. The other point to bear in mind is that the WACC fell consistently over the period shown from 7% pre-tax in 1996 to 6.54% (pre-tax, or a vanilla WACC of 5.05%) to 4.55% (vanilla) in 2013 (for the original period 2013-21). The depreciation formula changed from an asset life of 33 yrs. in 2001 to 20 yrs. in 2007 and then to 45 yrs. in 2013. The volume of electricity carried over the NGET's network rose form 268 TWh in 1990 to a high of 314.8 TWh in 2005 and then fell to 265.5 TWh in 2016, as efficiency improvements reduced final net demand and household solar PV displaced some metered demand.[13]
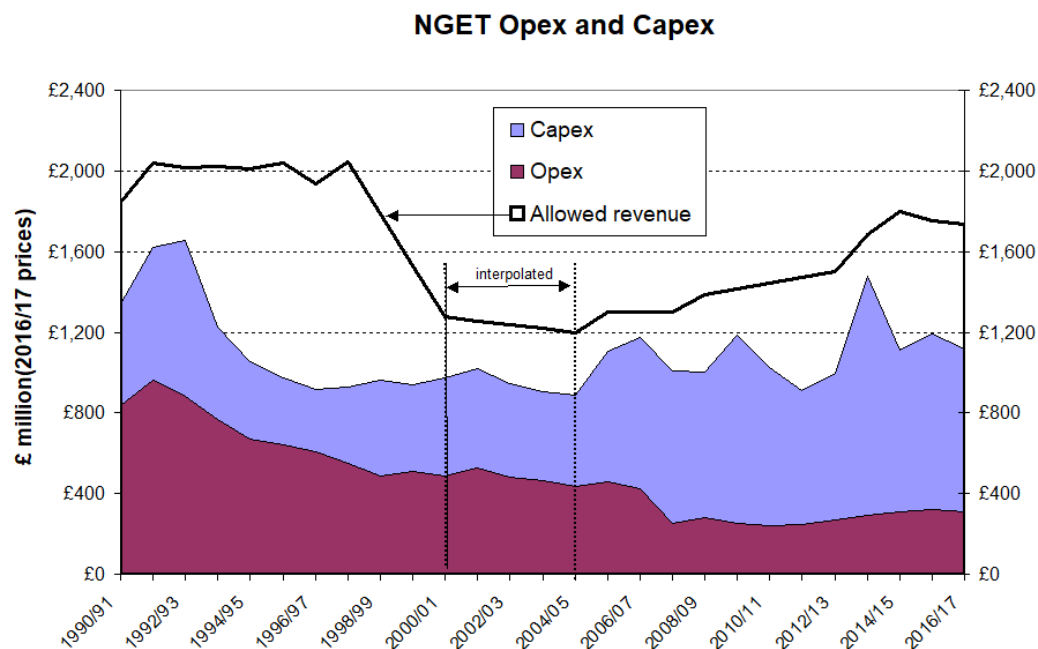

Figure 2 Investment (capex), operating costs (Opex) and allowed revenue for NGET
Source: Ajayi et al. (2022) data appendix
Note: Data for Allowed revenue is not available between 2000/1 and 2004/5

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[13] While it does not appear possible to find the required components of the allowed revenue earlier, there is a detailed financial model setting out the RAV, WACC and depreciation in Ofgem (2021).

4. Transmission charging

Transmission charging and connection arrangements should encourage the least system cost of delivering reliable electricity to end consumers while meeting the Government's decarbonization targets. Least system cost means taking account of all environmental externalities such as air and water pollution as well as greenhouse gas emissions and includes the cost of the networks and generation needed to satisfy the reliability standards. The most important way to reduce total system cost is to give correct signals for locating investment, as once made that cannot be changed. Daily dispatch signals can be important but can be addressed at any time after the investment decision.

The tariffs should therefore signal when, where and what type of generation should connect, and guide the least-cost evolution of the networks. In the short run the tariffs should also encourage the least-cost feasible dispatch of the connected assets – generation and trade over interconnectors. The charging regime should be considered fair (although this is primarily a task for the distribution companies setting final tariffs), credible and predictable (thus giving assurance to investors and lowering finance cost) and ideally as transparent as possible. Transmission charging is only one part of electricity market design that contributes to least-cost delivery. The rest of the electricity system also needs to operated efficiently and support mechanisms should not impede or work against the transmission location signals. The rest of this section will start with a brief history of the various problems in delivering this goal, and the reforms made to improve charging and connection agreements.

Before privatization the CEGB sold to regional Area Boards and devised a system of zonal charging, which continued with various modifications after privatization. This was fortunate as the principle of using tariffs to reflect the costs of delivering power to different destinations was relatively unusual in the European Union. Norway and Sweden had similarly sharp regional tariff variations, and to a far more muted way so did Ireland and Romania (ENTSO-E, 2020, table 4.1), but other countries lacked location guidance for generators.

At privatization National Grid had not fully agreed a set of principles for setting the Transmission Network Use of System (TNUoS) tariffs. Deciding on the methodology and its implications was left until after privatization. This was unfortunate as subsequent changes had to deliver the same regulated revenue agreed in the privatization offers to shareholders, so all changes were reallocations of the existing pie. The initial result was driven more by political expediency than logic. After the first price control period, the methodology and resulting tariffs have been almost continually consulted on and modified, incrementally adjusting the tariffs paid by generators and demand (or Load) each year, and more systematically with each new price control period. As a general point and at any moment changes to TNUoS will always be perceived as a near-zero sum game. Even when changes would lead to a more efficient dispatch in the short run, or a better location of investment in the longer run, the benefits will always seem small (and probably invisible) compared to the individual changes. The implication is that the regulator, Ofgem, should always consider grandfathering existing tariffs to generators, leaving it free to offer quite different contracts to new entrants, as existing generators cannot move or respond to the current TNUoS arrangements, but can protest and delay changes.

National Grid publishes the methodology behind the tariff setting, which are set out in the *Connection and Use of System Code* (CUSC). The CUSC is modified to reflect changes, but the principles are straightforward. "Generators pay to use the network to transport their electricity supply to where it's needed, and directly connected consumers and suppliers pay to use the network to meet their electricity demand."[14] The current method for setting tariffs is based on the Investment Cost Related Pricing (ICRP) methodology set out in Section 14 of the CUSC, which is intended to signal the long-run marginal cost (LRMC) of providing more capacity for delivering electricity from generation to load. The concept assumes (implausibly) that transmission lines can be incrementally and instantly increased in response to an increase in injection of 1 MW matched by a 1 MW increase in demand (proportional to load in each zone). In addition, NGESO is understandably reluctant to make large changes to tariffs to avoid creating uncertainty for future investment decisions, and so makes only gradual adjustments. Of course, LRMC pricing is always problematic for lumpy investments with long construction periods and long lives, but as generators make long-term and largely irreversible commitments, perhaps short-run discrepancies between the short and long-run marginal transmission costs are not so problematic. A more serious objection is that ICRP assumes no change to the existing network topology, or in effect that the original network topology was robust to future changes in demand and generation. This might have been acceptable under the CEGB that planned the network and the large fossil plants together, and perhaps when new gas entry was footloose and could be directed to least system-cost nodes, but became increasingly problematic with the radically different location choices of renewables, particularly as their location decisions were distorted by the support system.

The cost of transporting electricity does depend to a modest extent on distance and current (amps). Resistance losses are proportional to the square of the current, hence marginal losses are twice average losses. However, the main cost is cost of servicing the network capital cost. Hence the larger part of tariff revenue should be set to recover the fixed costs, with a variable locational element reflecting loss factors and congestion. The GB approach has been to set annual fixed tariffs but more recently also differentiated by patterns of generation use, although since 2016 balancing costs take account of system losses.[15] Generation tariffs (G-TNUoS) are paid on Transmission Entry Capacity (TEC, kW), regionally differentiated to reflect the notional costs of transport from each zone to demand, as shown in figure 3. To put the numbers in perspective, the range across GB is £45/kWyear, more than twice the clearing price in the first capacity auction. For a generator running on base load for 6,000 hours per year the range translates to £7.50/MWh compared to a pre-pandemic wholesale price of around £50/MWh and comparable to the clean spark spread.[16]

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[14] See e.g. https://www.nationalgrid.com/sites/default/files/documents/Introduction%20to%20TNUoS%2C%20BSUoS%20and%20Connection%20Charging.pdf

[15] Under the The Energy Market Investigation (Electricity Transmission Losses) Order 2016 at https://assets.publishing.service.gov.uk/media/5851404c40f0b60e4c0000bb/energy-market-transmission-losses-order-2016.pdf

[16] The wholesale price of electricity *less* the carbon-inclusive gas cost in a CCGT.
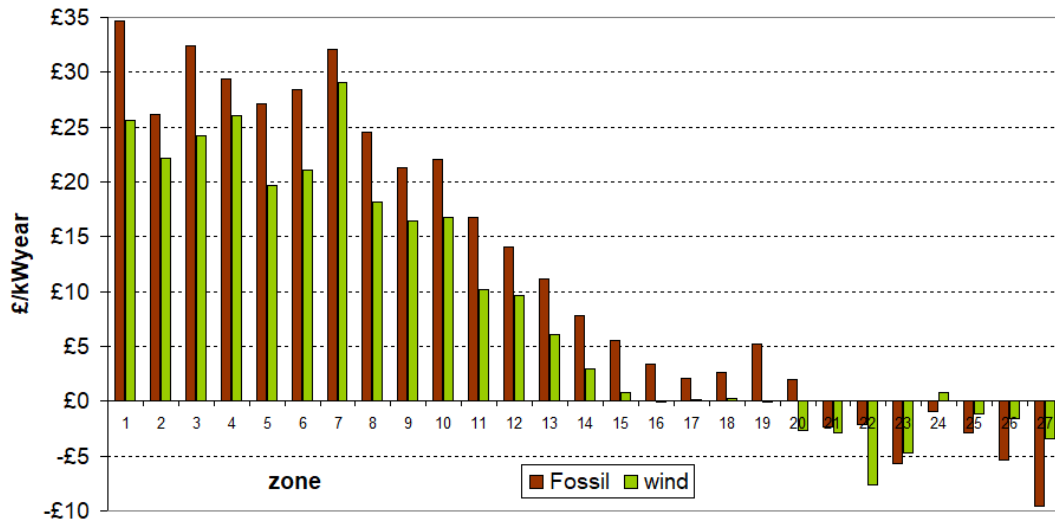
TNUoS Tariffs 2021-22

Figure 3 Transmission Use of System tariffs for Generation in 2021/22
Source: NGESO (2021a) gives the zone map: 1 is North Scotland, 27 is the far SW

The L-TNUoS tariffs are similarly regionally differentiated to reflect the cost of delivery to Loads. The sum of each zonal L and G tariff is roughly constant across the country, so the average wedge between the cost of injecting and withdrawing electricity from the grid is roughly independent of location and primarily set to recover the total allowed transmission revenue. The second feature is that the Distribution companies pay the L-TNUoS on the three Triad days, the three days of peak demand separated by ten days (which are predicted but not known until after the event). Generators in negative G-TNUoS zones are paid in proportion to their delivery in these Triad hours.

Initially the G tariffs collected about 25% of the total and the remaining 75% of TNUoS revenue was allocated to Load. In addition to TNUoS tariffs there are separate Connection Charges to recover the cost of installing and maintaining connection assets and Balancing Use of System (BSUoS) charges for the cost of day-to-day operations. Under reasonable assumptions in an isolated system the allocation between the G and L is irrelevant (Newbery, 2011). This is most simply seen if the sum of the tariffs were t per MWh, so that the cost of delivery to a consumer would be αt on G plus $(1 - \alpha)t$ on L (where α is the share to G) summing to t. However, GB is (increasingly) interconnected to other countries (Europe and the island of Ireland), where their generators pay different amounts, often zero, and would therefore be at a distortionary advantage compared to GB generators. The EU eventually agreed that the average G tariff should be no more than €2.50/MWh, and consequently NGESO adjusted the tariffs to lower the average G tariff, essentially moving all the tariffs down by the same amount (hence the negative tariffs in figure 3). In 2020 the G share had fallen to 14%. Only three of the EU member states had a G share above 10% (ENTSO-E, 2020, Table 4.1), and only three countries had a higher share of fixed tariffs in their total transmission tariffs (many placing the larger share on energy (MWh) rather than on

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entry capacity). The average total transmission tariff per MWh for large base-load consumers in GB was slightly (17%) higher than the EU average.[17]

4.1 Reforms to the transmission charging regime

Each year NGESO publishes a new set of tariffs for the forthcoming electricity year (April-March), and periodically consults on minor changes to the CUSC. Larger methodological changes are consulted on and then imposed by the regulator, Ofgem. Thus the 2007 *Transmission Access Review* (TAR) was directed to speeding up renewables deployment to meet the EU 2020 renewables target. Ofgem (2008) set out guiding principles for timely and efficient connection arrangements "… driven by the current delays that the large volume of renewable generation and other forms of generation seeking connection to the transmission system …" Figure 4 shows the rapid increase in both Scottish and English wind (both on- and off-shore generation, although before 2018 there was little offshore wind in Scotland). As the required reforms required longer to introduce, Ofgem decided that meanwhile new connections would be expedited by "connect and manage". This would allow connection before the system had been adequately reinforced, potentially creating congestion but providing the relevant transmission licensees (NGET in E&W, SSEN and SP in Scotland) with an incentive to accelerate reinforcement.
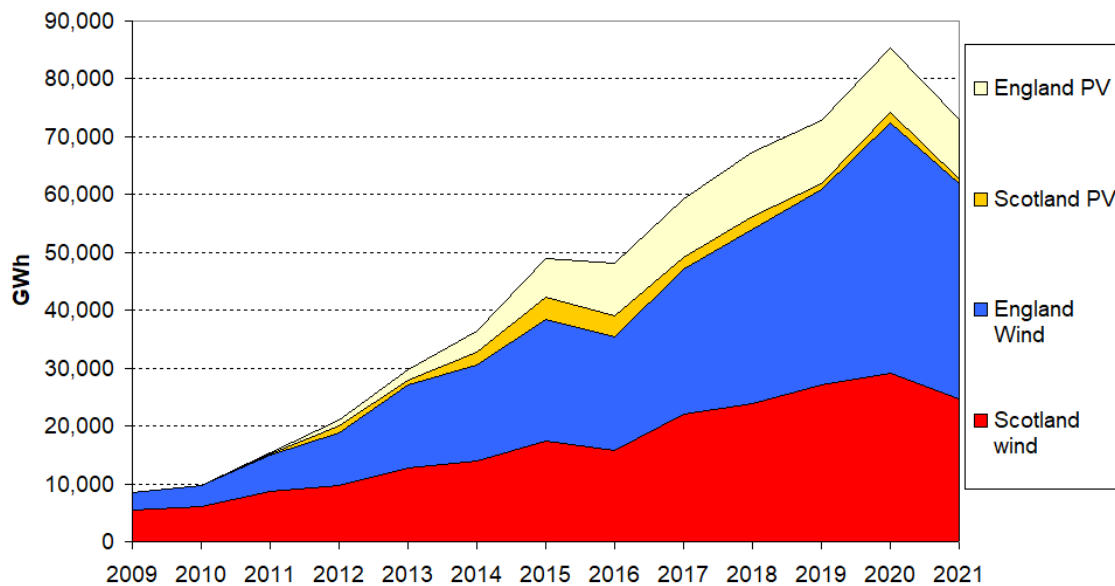
Figure 4 Generation of wind and solar PV in England and Scotland
Source: ET6:1 at https://www.gov.uk/government/statistics/energy-trends-section-6-renewables

The resulting impact on congestion costs at the Cheviot boundary between Scotland and England was mentioned above, exacerbated by the *Renewables Obligation* support scheme. This roughly doubled the value of wind generation and so amplified the benefit of

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[17] Population weighted, excluding GB as a non-EU member but including Norway

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windy locations (mainly in Scotland), overcoming much of the location signaling of the G-TNUoS tariffs. This example emphasizes the importance of ensuring the market and support designs are efficient so that transmission charging can concentrate on its own contribution to efficient location investment decisions.

The unsatisfactory outcome of the *Transmission Access Review* led to *Project TransmiT* in 2010 as "an independent and open review of electricity transmission charging. The project's aim was to ensure arrangements are in place to support the move to a low carbon energy sector whilst continuing to provide safe, secure and high quality network services at value for money to consumers."[18] In parallel, and given the evident need to reform renewables support, the Government passed the *Energy Act 2013* (HoC, 2013) phasing out the *Renewables Obligation* scheme and replacing it by a Contract for Difference with Feed-in Tariff (CfD with FiT). The CfD strike (support) price was initially set over-generously by bureaucrats and then by auctions (Grubb and Newbery, 2018; Newbery et al., 2018). The strike price applied to all metered output so a windy distant location with 3,000 MWh/MW would receive 50% more than one, perhaps located near load with 2,000 MWh/MW over the 15-yr. contract, potentially over-rewarding distant windy sites and exacerbating congestion.

After consulting, Ofgem (2014) published its *TransmiT* decision on how to improve cost reflectivity to come into force in 2016. This split the G-TNUoS tariff into a Peak Security charge and a Year Round tariff. The second adjustment is to adjust the 'shared' element of the Year Round tariff by a generator's average annual load factor …" (Ofgem, 2014). This change is reflected in the difference between wind and conventional base-load generation G-TNUoS tariffs shown in figure 3. "Once the proportion of a low carbon generation in an area exceeds 50%, then part of the Year Round tariff will be classed as 'non-shared'. The proportion of the Year Round tariff that is non-shared will increase as the percentage of low carbon generation increases. Only conventional generators would be charged the Peak Security charge, as intermittent generators (wind, PV) are assumed not to contribute to meeting peak security.

4.2 Reforms prompted by the capacity auction

The next substantive change was also prompted by the *Energy Act 2013* (HoC, 2013). One of the main motivations for market reform was the lack of new entry in the NETA energy-only market and the exit of some nuclear and old coal-fired stations. With considerable policy uncertainty (about renewables and other emissions targets and future carbon price levels) the capacity needed for a reliable and secure electricity system was not forthcoming. The *Energy Act* introduced capacity auctions, so from 2014 new generators could bid for 15-year capacity contracts and existing generators for a one-year contract at the same clearing strike price. The contracts would pay an amount per kW of de-rated capacity if they were available in stress periods (announced four hours ahead of time). The first auction was apparently successful in that it cleared at just under £20/kWyr., only 40% of the predicted cost of new entry (Grubb and Newbery, 2018), and half the G-TNUoS tariff range of figure 3. However, the largest

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[18] See https://www.ofgem.gov.uk/energy-policy-and-regulation/policy-and-regulatory-programmes/project-transmit . One of the commissioned papers was by the present author (Newbery, 2011).

successful bid (for two large CCGTs) subsequently withdrew when it failed to convince its financiers of its viability at that low price.

More troubling for the Government's decarbonization goals, a large number of very polluting small (11MW or less) reciprocating diesel generating sets connected to distribution networks won contracts. The reason was simple – connecting to NGET's Main Interconnected Transmission System (MITS) required payment of G-TNUoS tariffs, but connecting to the distribution network allowed them to be credited with avoiding the L-TNUoS tariff of importing from the MITS (the "embedded benefit"). The difference between the G and L-TNUoS tariffs was largely driven by the country-wide wedge (the sum of the two, about £60/kWyr.) – the "residual charge" designed to collect a growing and by now large part of the required regulated revenue. Distribution connection was therefore equally and hugely beneficial everywhere (so no location guidance) compared to transmission connection, provided the generator was small enough to be accepted into the local network.

Immediately the auction results were published in 2014 this deep flaw in the consistency of charging generators across different voltage levels was highlighted. It took Ofgem many years to consult on and finally rectify this flaw in the *Targeted Charging Review* (TCR), published five years and four auctions later (Ofgem, 2019). "(TCR) was set up in response to the changing role of the networks as more electricity is generated from a wider range of sources, including from smaller scale generators, and as demand becomes more flexible both in terms of time and location…The TCR has focused on the ongoing 'residual' charges which aren't supposed to send signals for how the networks should be used. … We have decided that the Transmission Generation Residual charges should be set to zero … The reforms to Embedded Benefits will affect revenue streams for all generators (including renewable generators). Our analysis indicates that by removing distortions caused by these charging arrangements, similar levels of decarbonization can be delivered at significantly lower costs to consumers. Our analysis indicates that these reforms will provide significant savings to consumers of £3.8bn to £5.3bn and system benefit of £0.8bn to £2.9bn over the period to 2040." (Ofgem, 2019, p8-9). The size of this saving is a measure of the high cost of inefficient location signals.

4.3 Integrated Transmission Planning and Regulation Project (ITPR) 2012-15

Reforms to the charging methodology could improve location decisions of new entrants and so make better use of existing transmission capacity. However, "No party currently has responsibility for taking an overarching view of system development, leading to a risk that opportunities for coordination are not recognized or acted upon" (Ofgem, 2014). There was also concern about how to coordinate regulation across networks on and off-shore, including interconnectors, especially where the interconnector might also include an off-shore wind farm connected to and potentially selling to two or more different jurisdictions.

Strbac et al. (2014), in response to ITPR discussions, identified various problems and solutions, including the potentially perverse incentive under RAV regulation (much like rate-of-return regulation criticized above) for National Grid to seek asset-heavy solutions to problems. Some evidence of this was provided by National Grid's 2011 proposals to build two multi-£ billion "bootstraps" – HVDC offshore links to export power from Scotland to England to relieve congestion on the Scottish border. Ofgem (2012) approved the "Western

Bootstrap" – a high voltage £$_{2010}$1.05 billion off-shore HVDC link, 50% owned by SPT, but deferred considering the even more costly "Eastern Bootstrap" (although this has since reappeared as part of the *Holistic Network Design* for off-shore wind; NGESO, 2022). Eventually, as shown above, the transmission owner (TO, in this case NGET) and System Operator (SO, in this case NGESO) functions were separated, with a proposed transfer of NGESO to a Future SO with wider planning powers and avoiding the bias to asset-heavy solutions. Problems of funding large new transmission like the bootstrap were addressed by the change of regulation from RPI-X to RIIO (see above).

4.4 The Review of Electricity Market Arrangements (REMA)

By 2021 the Government considered it was time for its fourth attempt to improve electricity market arrangements, because it did "not consider that existing market arrangements are likely to deliver our ambition for a decarbonized and secure electricity system by 2035 at least possible cost to consumers, …. We therefore conclude that there is a strong case for change." (BEIS, 2022, p43). The scope of the consultation included wholesale market design including Location Marginal Pricing (LMP), the capacity auction, renewables support schemes and transmission pricing, with an emphasis on taking a holistic systems view. At the time of writing the Government had not decided what to change but has published the consultation results.[19] The following are the author's own views of desirable changes.

One of the key motivations for launching REMA was NGESO's forecast of alarming increases in constraint costs. The *Network Options Assessment* (NOA6) "… shows modelled constraint costs increasing significantly this decade - from c. £0.5bn/year today to between £1bn and £2.5bn/year …. This is a result of the rapidly changing generation mix, with significant quantities of new renewable generation connecting, and the fact that the timescales required to make the large transmission investments to increase network capacity to fully accommodate all of this new generation can be much longer." (NGESO, 2021b.) Constraints require the ESO to require constrained-down generators to buy back their excess notified output at their avoidable cost, while replacing that from other generators who are paid the extra cost of turning up.

Energy Systems Catapult (2021, p12) argued that consumers would avoid (or shift) these high constraint costs by introducing nodal pricing/ LMP. It claimed "The aim of locational price signals is to ensure network users internalize the impacts of their behaviour/decisions on the costs of the total system. This will then ensure users:

a) invest in the right places; and

b) consume or produce at the right times."

LMPs are standard in the US, and have been successfully operating for several decades around the world. Energy Systems Catapult (2021, p30, citing Neuhoff & Boyd, 2011) argue that introducing LMP delivers benefits that typically pay back the transition costs in one year. However, most real-world estimates (rather than simulations) show the costs and benefits starting from an existing system of central dispatch, which GB abandoned

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https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1140189/review_of_electricity_market_arrangements_summary_of_responses.pdf

in 2001. The extra cost and time of introducing day-ahead central dispatch would be considerable and take several years. Thus the cost of moving from the Pool to NETA was estimated by the National Audit Office to be £$_{2001}$ 580 million (NAO, 2003). The other reason for skepticism about forecast costs or benefits of a move to LMPs is that many rely on more efficient and cheaper investment signals under one system or the other – where the counterfactual of designing efficient long-term contracts is normally not adequately discussed.

Conceptually, LMPs are the market clearing price at each node that balance demand at that node with the supplies that can be delivered to that node, taking account of transmission constraints and losses. In a competitive market with complete information the LMPs would be the marginal cost of delivering power to that node (or the willingness to pay to avoid reducing demand), and hence the efficient price (Schweppe et al., 1988). This Standard Market Design (SMD, the US name for nodal pricing with security constrained optimal central dispatch), is the natural reference model against which to compare alternatives. Other market designs might be superior for a number of reasons, such as avoiding the very considerable cost of making the change from the current energy-only self-dispatch market. Further, the SMD is only efficient with truthful information revelation and alternative designs might reduce information incompleteness and the associated temptation to offer non-cost reflective bids. Other designs might more effectively deliver investment, innovation and better contracts.

The decision whether the advantages of LMP outweigh the transition costs by sufficiently increasing efficiency and lowering system costs is an empirical one and system dependent. There are also modest market design changes that fall short of the full SMD but which might offer most of the benefits of the SMD with lower transition costs (and speedier implementation). This rest of this section sets out the potential benefits of the SMD, illustrated with a simple numerical example in Appendix A, and considers intermediate and simple reforms that might achieve most of these benefits without introducing the full SMD.

The present system allows all generators to sign contracts with off-takers at the day-ahead (DA) stage (and earlier, but that makes little difference to the argument). The generator announces planned delivery in a Final Physical Notification (FPN) and the off-taker similarly submits a balanced demand equal to the planned injection with her generation counter-party. Any deviations from FPNs are transacted through the balancing market. All balance-responsible generators submit complex offers to the System Operator (SO), setting out technical constraints (e.g. on ramping rates, minimum warm-up time) and the price at which different volumes can be injected at each accessible node. The SO also needs to procure reserve capacity ahead of time to meet the risk of the single largest plant or line failure (the N-1 constraint). The reserve plants need to be committed (i.e. running and synchronized ready to increase output) and hence immediately available for dispatch if needed.

The DA market clears ignoring all transmission constraints, so the DA price is the marginal price of the least expensive generator needed to meet demand. The SO then operates the balancing market (BM) to remedy mismatches between FPNs and actual dispatch, as the system must balance demand and supply second by second. A shortfall in supply will cause the frequency to drop as the system extracts inertia from the spinning mass of the turbines to

maintain balance, but supply must be rapidly increased (or demand reduced) to ensure frequency (and hence quality of supply) remains within the specified band (49.5-50.5 herz).

The SO also has to resolve any constraints that make individual FPNs infeasible because of limited transmission capacity. The SO instructs generator to constrain down to satisfy transmission constraints, and chooses the least-cost set of generators to make up that shortfall. Clearly these will be more expensive than the original generators. The extra balancing costs will need to be recovered according to some rule.

The simplest reform that might improve efficiency would be to change the current balancing market into a real-time security-constrained central dispatch with associated LMPs (like the SMD) but limited to balance-responsible generators (who need to be centrally dispatched anyway). The question addressed below is how this simple adjustment to the current market design might fall short of the full DA SMD.

Compared to a well-designed DA central dispatch an energy-only market may suffer from restricting offers to a single marginal price that may fail to recover fixed costs unless marked up above avoidable cost. The resulting system price may no longer be at the marginal cost of the most expensive generator, and the set of generators may differ from the least-cost set if cheaper sets mark up more than more expensive sets.

The most efficient incentive-compatible revenue-adequate solution to finding the set of generators needed to meet demand is for the generators to declare their fixed costs and operating constraints and for the dispatch algorithm to make any necessary top-up payments to achieve revenue adequacy (as in the original Electricity Pool and in the SMD).[20] Again, it is an empirical question whether the current energy-only market rules and codes are adequately incentive-compatible and elicit correct information.[21] There is a nice trade-off between the single bid price of energy-only markets that require generators to decide how much to price above short-run avoidable cost and risk inefficient dispatch, and the complex bids (start-up, no-load, unit energy costs at each level of output, minimum up and down time, ramp rates, etc.) which, if truthful would be efficient, but which offer opportunities for more efficient rent extraction by overstating the fixed cost element. The UK Competition and Markets Authority investigated potential market power in the GB electricity wholesale market and "found no evidence that companies are able to exploit market power, our analysis of wholesale electricity prices suggests they have been reflective of costs and there is no evidence of generators having made excessive profits over the period we reviewed." (CMA, 2016, p2.)

The next potential inefficiency is that the set of generators committed (including those by the SO for the N-1 constraint) is not least-cost given the actual constraints – as is the case in the Appendix A example. How serious this is will depend on whether the SO anticipates

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[20] It is evident that it is more efficient to extract rent from the fixed cost element than marking up on variable costs and risk selling less and foregoing profit, but the risk is that too high a fixed cost may result in non-dispatch.

[21] There is an important and recognised need for adequate market monitoring for any market design, including the SMD, see e.g. https://www.proactiveinvestors.co.uk/companies/news/1006296/ofgem-to-clamp-down-on-balancing-market-profits-but-what-does-it-mean-1006296.html. One market power mitigation strategy is to require enduring statements on all the technical parameters and costs, subject to periodic audit, to minimise the temptation to exploit temporary market power.

correctly future constraints, and adjusts the required reserve margin (to match the predicted final dispatch) and whether it would always be efficient to commit those choosing to contract DA. Both of these inefficiencies (distorted pricing leading to costlier commitment, the DA commitment differing from the security-constrained least-cost commitment) result in real resource cost increases. This again is an empirical and system-specific question. Wolak (2011) estimated that when California introduced nodal pricing fuel costs fell by 2%, a real resource saving, not just a reallocation of existing costs to different parties. Savings from efficient early commitment are likely to be higher for plant with lengthy commitment periods that are near the margin of profitability, like coal-fired plant. Nuclear plant is always profitable to commit and maintain on the system unless withdrawn for faults or maintenance. Flexible gas plant (suitable CCGTs) may be able to commit and become available in time to help adjust demand and supply. Much also depends on the accuracy of wind, solar and demand forecasts sufficiently far ahead of dispatch.

The final and most obvious difference between the full SMD and our current system (even if modified with an LMP balancing market) is that consumers pay more and generators earn more profits in the current market than in the SMD. This is easily seen where constrained generators book the entire profit of the DA FPN even if constrained, and at best they will pay avoidable costs on their output reduction, retaining their original profit from an infeasible dispatch. If they bid into the BM at a constrained-down price below avoidable cost they will pay this lower bid and avoid a higher actual operating cost, and hence will make even higher profits. At best replacement generation will be paid the extra cost of generating (which will clearly be higher than the savings on the constrained-down plant). If they overstate their unit costs again they will make a profit on their balancing actions. Together these balancing actions to correct the infeasible DA FPNs will be costlier than if the original dispatch had been feasible and least cost.

With a move to a balancing SMD, if the set of plant committed in the energy-only DA market were the same as in the DA SMD, the plant actually dispatched would be the same and the only difference would be the starting point (day-ahead SMD outputs or energy-only FPNs) from which to charge the balancing LMPs. All deviations would be compensated, and if the bids into the balancing market were competitively set at marginal adjustment costs, the adjustments would be profit-neutral.[22] However, even in this minor design change, consumers would pay more and generators earn more from starting the LMP adjustments from different starting points. Nevertheless, these higher consumer costs highlighted in NGESO's estimate of constraint "costs" are not all true resource costs, but largely higher consumer costs balanced by higher generator profits.

So how material are the benefits of full LMP rather than modest changes to the BM? If the residual demand (demand less Variable Renewable Electricity, VRE) is reasonably accurately forecast at the last moment at which the most suitable flexible plant can be committed, then optimal dispatch (and associated LMPs) can be left until that moment. If that is day-ahead we are back to central dispatch and a world of gradually updated LMPs, right down to dispatch. If we are moving to a more flexible world with excellent weather forecasts

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[22] This assumes, empirically plausibly, that cost variations around a positive operating position are roughly linear.

so that commitment decisions can be left to the few hours before dispatch, then LMPs could be confined to the real-time adjustments from the contract positions taken by generators and suppliers ahead of time. The benefit of confining LMPs to balancing actions is that the required system changes are likely to be less onerous than those needed for a full day-ahead central dispatch model.

All contract positions[23] would now have to be (at least by default) delivered to or from the national hub (the node at which the G-TNUoS charge is zero) – rather like to the national market at present, and all deviations of outcome to contract position would be priced at the real-time LMPs, just as at present they are charged at balancing prices. The existing TNUoS charges would confer Financial Transmission Rights to the hub. If the day-ahead contract positions were feasible and were delivered exactly, the financial outcome would be as at present, otherwise the deviations would be priced at LMPs, compared with the existing balancing charges. The main difference would be the apparent need in the balancing market to make payments for resolving constraints with their adverse publicity (of compensating generators NOT to generate), as these would be automatically handled with the LMPs.

4.5 Investment location signals without full LMP

Given that the introduction of central dispatch and day-ahead LMPs would take many years and that the most valuable gain from locational signals is to make the right locational investment decisions, Newbery (2022) argued that two simple changes could be introduced almost overnight and would achieve this goal with minimal disruption. The first change is for NGET to offer long-term (15-25 year) tradable indexed TNUoS contracts to prospective new generators. These contracts would be tied to the location and generator type, and would signal the best forward-looking estimate of the least system cost location for each type of generation allowing for any lags in network reinforcement. They would reflect the incremental system cost of delivering that type of generation output profile to demand. All existing G-TNUoS tariffs could be grandfathered to avoid complaints from incumbents, for whom location decisions are no longer relevant. This is not without precedent as offshore transmission contracts (discussed below) are for 20 years.

The necessary accompanying change would be a slight modification of the auctioned CfD with FiT contracts for Variable Renewable Electricity (VRE). This would pay the auctioned strike price not, as at present, on metered output but on the day-ahead forecast local output of the VRE, regardless of actual output. The contract would be for a fixed number of full operating hours (e.g. 40,000 MWh/MW). The result would be to remove excessive incentives to locate in distant windy or sunny sites, and pay comparable amounts to cover the fixed and regionally similar investment costs. (The justification for this change is given in Newbery, 2022; 2023).

Combined with an announced sequence of VRE auctions to meet the required targets, these mild changes (to CfDs together with an FSO charged to offer forward-looking

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[23] The normal wholesale contracts would be a contract for difference, CfD, that transfers $(p - s)M$ to the generator, where p is the reference (hub) price, s is the agreed strike price, and M is the agreed volume (MW). This can be associated with a Financial Transmission Right, FTR, from node n that transfers $(p_n - p)M$ to the generator at n where p_n is the LMP there, together giving a resulting financial hedge of $(p_n - s)M$.

contracts) should deliver efficient location decisions. The modified (yardstick or deemed) CfDs should also solve the problems of constraining off excess VRE as the actual dispatch choice will be guided by the spot price (which could be a zero LMP) automatically dealing with constrained-off payments. The contracts for G-TNUoS and yardstick CfDs would need to be designed for LMPs when and if introduced by providing suitable yardstick FTRs.

5. Offshore transmission regime

Offshore wind has been Britain's remarkable success story. The first commercial-scale offshore windfarm was installed in 2003 and by 2022 Britain had 11 GW operational. The April 2022 *British Energy Security Strategy* target is 50 GW of offshore wind by 2030 (compared to peak GB demand of roughly 60 GW; BEIS, 2022, reaffirmed by HMG, 2023). The ownership structure of off-shore wind is quite complex. The Crown Estate owns the rights to the seabed out to 12 nautical miles and rights to exploit the seabed for renewable energy out to 200 nautical miles or to the boundary of international waters. "The Crown Estate is constituted as a statutory corporation under the *Crown Estate Act 1961*…Independent of government and the monarch, The Crown Estate's public function is to: invest in and manage certain property assets belonging to the monarch; and remit its revenue surplus each year to the Exchequer,[24] although a fraction is passed to the monarchy.

5.1   The OFTO regime

At each round, the Crown Estate lists sites to lease for off-shore wind and developers bid for the right to exploit them. If successful they build the off-shore wind farm (OWF) and almost invariably the link to shore and the assets needed at each end to connect the OWF to the grid. The UK does not allow generators to own transmission, and Ofgem's original idea was that a separate company would contract for and build the link to shore. However, the difficulty of coordinating construction of the OWF and the link to shore made this so unattractive (with problems of potential hold-up) that Ofgem allowed developers to build everything and then for Ofgem to auction off the (efficient) cost of the link to Offshore Transmission Owners (OFTOs), typically finance houses or banks. NGESO collects the revenue for the OFTOs through a variety of extra substation and line charges, described below and in NGESO (2021, p13).

The auction determines the price that the OFTO will charge the OWF in £/MWh (indexed) for 20 years in return for the agreed OFTO payment to the developer. As a regulated asset OFTOs should have access to low WACCs, but the National Audit Office found that the first two rounds incurred extra transaction costs and considerable delays (NAO, 2012, p24-6). Under the OFTO regime the transmission tariffs for the first four projects averaged £$_{2012}$45.65/kWyr. The annual payments averaged 11.14% of the asset value, but the OFTO is also responsible for the licensee's transaction costs totaling £24.7m. and O&M, which varied from 0.9% to 4.4%, with the winning bids at the lower end (NAO, 2012, p26, 30). The simple average of O&M for the lowest four bids is 1.2% and if this is deducted from the agreed annual payments the average estimated WACC for the first four projects averaged 7.7% real (after adding £24.7 m. up-front transaction costs to the £254 m

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asset value, and deducting O&M costs to give £$_{2012}$ £25.5 m. net income) to purchase the OFTO assets of 620MW for £254 m.

The alternative to competitive bidding for these OFTOs would presumably have been to transfer them to the regulated TO (e.g. NGET for E&W) and include the Ofgem-approved efficient cost into the RAV, earning the regulated WACC which for NGET in 2010 was 5.6% real pre-tax. If in addition the transaction costs were largely avoided, and NGET has been allowed 5.6% WACC, the annual gross payments would have fallen from £28.3 m. to £23.85 m., or a saving of 15% each year for 20 years.

The total actual transmission tariffs payable by an OWF are made up of a number of elements linked but not necessarily equal to the payments made to the OFTO. SSEN (2021) gives a useful explanation and illustration: "OFTO revenues are paid by the ESO. The ESO recovers the majority of this cost through local TNUoS tariffs paid by offshore generators, however some of the OFTO allowed revenue is socialized across other areas of TNUoS." Thus for the Greater Gabbard OWF (20km from the Suffolk coast, 500 MW, commissioned in 2011 with a load factor of around 45%) the total payment is made up of two parts. In 2021/22 the offshore local substation charge was £16.473633/kWyr. and the offshore local circuit charge was £38.093075/kWyr. or in total £$_{2021}$54.57/kWyr, giving a total local offshore tariff of £27.3 m. The allowed OFTO revenue was £32.1 m. with the balance socialized over NGESO's revenue. In addition, the OWF has to pay the zonal G-TNUoS tariff, which for zone 14 in the SE of England was £0.2799/kWyr. The total annual tariff was therefore £$_{2021}$54.85/kWyr. or £14.23/MWh.

In contrast, for an OWF like Beatrice (13 km. from shore in the Murray Firth, NE Scotland, 588 MW, commissioned in 2019, 49% capacity factor) the TNUoS tariff is £$_{2021}$22.23/kWyr. Ofgem allowed an OFTO cost of £438m. in 2021.[25] Ofgem allowed an OFTO revenue of £18.34 m.[26] or £33.35/kWyr. If the same fraction of this is socialized as Greater Gabbard (15%) the final local offshore tariff would be £28.34/kWyr, and the total off and onshore transmission tariff would be £$_{2012}$43.55/kWyr. or £$_{2012}$10.14/MWh. In both cases these energy charges are a high fraction of recent CfD prices.

5.2   Licensing offshore sites and determining the support payments[27]

The Crown Estate announces the sites for licensing in a series of rounds. The first round of offshore development began in 2000, catering for "small scale projects of up to 30 turbines. A total of 18 sites were awarded..." In 2003 round 2 awarded licenses for "the UK's first commercial-scale offshore wind projects, playing a critical role in validating the role the technology could play in the nation's electricity market. Under this round, over 7 GW of capacity was awarded."[28] In the event only 12 of the round 1 projects were completed, the last in 2013, totaling 1.2GW. "Five projects were withdrawn based on environmental grounds."[29] Round 1 wind farms paid a rent of £$_{2001}$0.88 (£$_{2012}$1.15)/MWh (DTI, 2001, p33).

[25] https://www.ofgem.gov.uk/sites/default/files/2021-07/Beatrice_CAR_final%20for%20publication.pdf

[26] https://www.ofgem.gov.uk/sites/default/files/2021-06/beatrice_s8a_notice_9_june_2021.pdf

[27] I am indebted to Hongyun Zhang for evidence on option and rental fees described in this section.

[28] https://www.thecrownestate.co.uk/media/3346/4043-tce-role-in-uk-offshore-wind-final.pdf

[29] https://guidetoanoffshorewindfarm.com/offshore-wind-history

This rent continued for Round 2 (DTI, 2001, p44). This rental was therefore a small fraction of the relatively high receipts by early wind farms.

In 2010 rounds 1 and 2 were extended and four projects were awarded (1.6GW), while in 2009 five Scottish projects were awarded (4.8GW). The round 3 results were announced by Reuters in 2010 "which together could add at least 25 gigawatts (GW) of power generation capacity by 2020."[30] The early demonstration schemes were funded by the DTI's Capital Grants Scheme. "(T)hree rounds of offshore wind grants totaling £117 million have already been allocated."[31]

After the first three rounds, the process of selecting zones and leasing the sites selected by developers within these zones appears to have changed. The Crown Estate identifies zones (four, all off the English coast in Round 4) and developers bid the level of option fee they are willing to pay for their preferred locations and MW within these zones. The successive auction rounds then determine the winners, as those whose bids are highest and exhaust the amounts or areas on offer. Successful bidders have to pay the Crown Estate an option fee for each year until the wind farm is commissioned, and then an annual rent.

Table 1 gives the results for Lease Round 4 in 2023, where the option fees are payable for a minimum of 3 years and a maximum of 10 years. As this shows, the Crown Estate will receive £880 million/yr. for at least three years equivalent to £110/kWyr. (c.f. the capacity auction clearing price of £20/kWyr. and the range of G-TNUoS tariffs of £45/kWyr.). As to the annual rent "(D)uring the pre-generation period (i.e. during construction), the rent payable by the developer under the Wind Farm Lease will be the lower of the annual option fee instalment (CPI indexed) and the base rent (being the minimum output multiplied by £0.90 (CPI indexed)). When the wind farm starts generating, the rent payable by the developer will be the greater of 2 per cent of gross turnover, the minimum output multiplied by a fee based on 2 per cent of the average project revenue over the previous two years, and the base rent." (Crown Estate, 2019, p43.)

Table 1 Crown Estate option fees for Leasing Round 4

Project capacity MW	area sq. km	option fee £/MW/yr.	total fee £m/yr.	Fee £'000/sq. km.
1,500	495	£76,204	£114	£231
1,500	495	£89,900	£135	£272
1,500	500	£83,049	£125	£249
1,500	497	£154,000	£231	£465
480	126	£93,233	£45	£355
1,500	322	£154,000	£231	£717
7,980	2,435	£110,336	£880	£362

Source: https://www.thecrownestate.co.uk/media/3920/round-4-tender-outcome-dashboard.pdf

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[30] https://www.reuters.com/article/britain-power-wind-idUKWLA218120100108

[31] https://webarchive.nationalarchives.gov.uk/ukgwa/20070604090834/http://www.dti.gov.uk/energy/sources/renewables/business-investment/funding/capital-grants/page19413.html

As these option fees are paid on installed capacity, they effectively add to the up-front capital cost of the wind farm, and it is convenient to express them as a percentage addition to the investment cost. DTI (2002, p21) estimates the windfarm construction cost excluding cables as £$_{2002}$750/kW = £$_{2012}$970/kW with a 35% capacity factor (for the early near-shore structures). BEIS (2020) gives the 2025 projected cost of an off-shore wind farm (excluding the infrastructure, assumed to be the OFTO part) as £$_{2018}$1,630/kW (£$_{2012}$1,480/kW) with a 51% capacity factor. The latter is more suited to the deeper waters of Round 4, where the option fee (for the minimum three years) is £$_{2021}$330/kW (£$_{2012}$284/kW), raising the investment cost by 17%. The ongoing rent at 2% of turnover depends on the strike price of the auction, discussed in the next section, which shows the clearing price at £$_{2012}$37.35/MWh. At a 51% capacity factor the gross revenue would be £167/kWyr, of which 2% would be £$_{2012}$3.30/kWyr, effectively lowering the strike price by 2% of 51% or just over 1%, small in comparison with the option fee.

These option fees seem unreasonably high, as they would have to be recovered by including them as costs to be recovered in the renewables auctions. The analyst at the Offshore Renewable Energy Catapult calculated the levelized cost of electricity (LCOE) "Using a weighted average cost of capital (WACC) of 4.5%, this comes to £36.26 per MWh excluding an option fee.[32] … In the 2030 reference site, we see LCOE increase 23% when an option fee of £150,000 per MW is applied over a development phase of four years."[33] Note that the average option fee was only £110,336/MW and the calculation above assumed only three years of payment, explaining some of the difference between a 17% increase in investment cost and the 23% increase in the LCOE.

Scotland was concerned about its rather low share in total GB off-shore wind so that in 2020 Crown Estate Scotland initially decided to cap the option fees at a maximum of £10,000/km^2 (incidentally incentivizing closer spacing of the turbines), well below those shown in Table 1.[34] However, when the results shown in Table 1 were published, the cap was raised to £100,000/km^2.[35] Much as before, "Rent will be payable quarterly based on the offshore wind farm output at a rate of £1.07/MWh indexed to CPI." Table 2 shows the results for the Scotwind auction.

All but one of the bids were at the £100,000/km^2 cap. At £31/kWyr. the option fee is only 10% of the English Round 4 fee and so would only increase the investment cost by about 2%, although these wind farms are costlier as they are in deeper water and further offshore, so the OFTO tariffs are likely higher. In addition, all OWFs have to pay the G-TNUoS annual tariff, which is much higher in Scotland (£22/kWyr in North Scotland compared to £1/kWyr off Kent), as shown above for Beatrice compared to Greater Gabbard.

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[32] Remarkably close to the CfD strike price of £39.65 but it is not clear whether this is in 2012 prices
[33] Source: https://ore.catapult.org.uk/blog/miriam-noonans-thoughts-seabed-leasing-4/
[34] https://www.crownestatescotland.com/scotlands-property/offshore-wind/scotwind-rapid-review
[35] https://my.slaughterandmay.com/insights/briefings/the-winds-of-change-option-fees-for-offshore-projects. Note however that zone N2 attracted only one bidder, who bid £10,000/km^2.

Table 2. ScotWind Leasing results 2022

Zone	Area sq.km	Technology	Award capacity MW	Option fee £ M	Average option fee £/MW
E1	859	fixed	2,907	85.9	£29,549
E1	859	floating	2,610	85.9	£32,912
E1	280	floating	1,200	28	£23,333
E2	860	floating	2,000	86	£43,000
E2	200	floating	798	20	£25,063
E3	187	fixed	1,008	18.7	£18,552
NE2	200	floating	1,008	20	£19,841
NE3	256	floating	1,000	25.6	£25,600
NE4	429	fixed	1,000	42.9	£42,900
NE6	134	floating	500	13.4	£26,800
NE7	684	floating	3,000	68.4	£22,800
NE8	330	floating	960	33	£34,375
N1	657	fixed	2,000	65.7	£32,850
N2	390	floating	1,500	3.9	£2,600
N3	103	mixed	495	10.3	£20,808
N4	161	fixed	840	16.1	£19,167
W1	754	fixed	2,000	75.4	£37,700
NE1	100	floating	500	10	£20,000
NE1	360	floating	1,800	36	£20,000
NE1	100	floating	500	10	£20,000
Total	7,903		27,626	755.2	
Fixed	3,047		9,755	304.7	£31,235
Floating	4,753		17,376	440.2	£25,334
Mixed	103		495	10.3	£20,808

Source: https://www.crownestatescotland.com/news/scotwind-offshore-wind-leasing-delivers-major-boost-to-scotlands-net-zero-aspirations

5.3 *The CfD auctions for offshore wind*

In addition to acquiring leases and consents, offshore wind developers would expect support as renewable generation. After the *Energy Act 2013* the system of supporting renewables changed to CfD with FiT, with contracts awarded initially in an allocation round and then by the CfD auctions. The first allocation round announced in 2015 set the strike price for offshore wind at prices ranging from the earliest for delivery in 2017/18 at $£_{2012}119.89$/MWh falling to $£_{2012}114.40$/MWh in 2018/19.[36] The second auction round in September 2017 for off-shore wind cleared at $£_{2012}74.75$/MWh for delivery starting in 2021/2 and $£_{2012}57.5$/MWh starting in 2022/23, less than half the bureaucratically announced price of the first round.

Subsequent CfD auction rounds continued to lower the strike price. The third round CfD auction in 2019 cleared at $£_{2012}39.65$/MWh for off-shore wind (and remote island wind) for delivery in 2023/4 and $£_{2012}41.61$ in 2024/5.[37] The fourth round cleared in July 2022, with

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[36]

https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/407059/Contracts_for_Difference_-_Auction_Results_-_Official_Statistics.pdf
[37] See https://www.gov.uk/government/publications/contracts-for-difference-cfd-allocation-round-3-results

offshore wind starting delivery in 2026/7 receiving a strike price of £$_{2012}$37.35/MWh. For comparison Scottish onshore wind cleared at £$_{2012}$42.47 for delivery in 2024/25, and solar PV at £$_{2012}$45.99 for 2024/25.[38] Figure 5 illustrates this fall in prices.
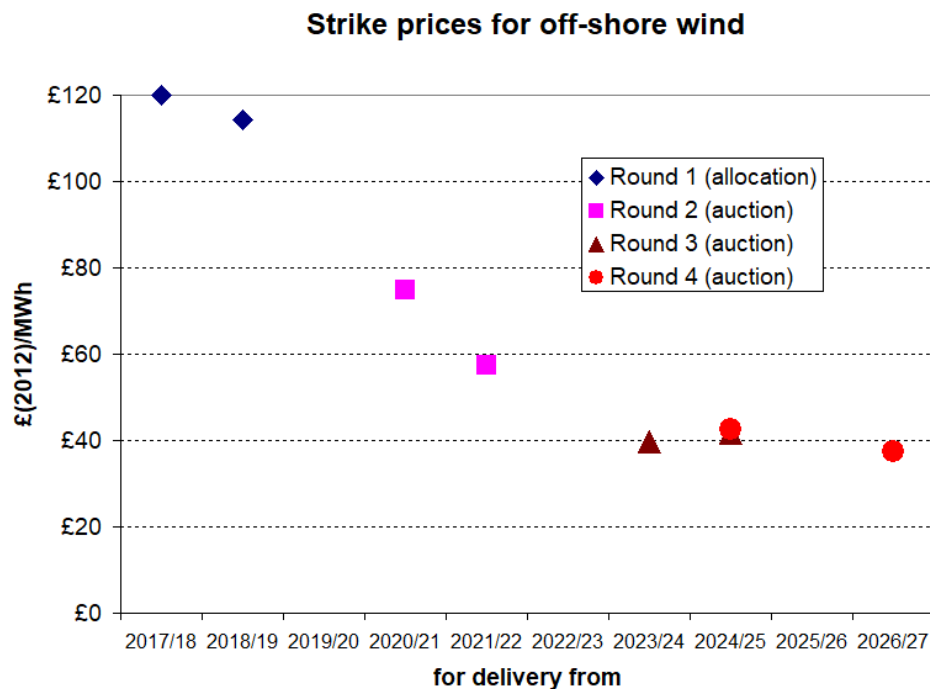

Figure 5 Strike prices for off-shore wind in CfD rounds
Sources: CfD results from Gov.uk – see text and footnotes

Note that these strike prices require the developer to absorb the cost of paying the OFTO and the Crown Estate rental and other lease fees, as well as the G-TNUoS for using the onshore transmission system, which collectively can add considerably to costs and hence reduce the revenue to cover the actual offshore wind investment. Given the high level of option fees and the recent escalation of construction costs in the post-Covid period, not to mention the high wholesale prices, there must be some concern that the CfD contracts will not be taken by large highly capitalized energy companies willing to sell in the wholesale market, collecting windfall profits (and/or covering the higher investment costs) until they decide to re-enter the CfD auction at a later round.

6. Coordinating investment in transmission and generation

The original attempt to coordinate investment in transmission and generation in a liberalized market was through setting cost-reflective transmission tariffs to guide generation location decisions. The early National Grid *Seven Year Statements* reinforced these signals by explicitly indicating where new entrants would be most welcome. These signals could be strengthened if they were directed solely at potential new entrants and provided asset-life assurance with the same type of long-term contract provided by OFTOs. Ofgem and the Government are increasingly attracted to anticipatory transmission planning (HMG, 2023,

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[38] See
https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1103022/contracts-for-difference-allocation-round-4-results.pdf

p23). Ideally this should look ahead to where VRE is likely to locate, given the forward-looking TNUoS contracts suggested above. The main problem is that if the planning role is left with the ownership of the assets, then asset-heavy solutions are likely to be preferred. That is an additional reason for ownership separation, as proposed in the publicly owned FSO. If the FSO could take on the role of securing consents for suitable VRE connections (as the Crown Estate does for offshore sites), then the FSO could take a more proactive role, avoiding the problems of capital bias (Felder and Athawale, 2022).

Offshore transmission planning provides a good example of the role that integrated planning can take. The potential benefits are illustrated by comparing the costs of coordinated planning with the earlier developer-led model in which each off-shore wind farm was connected by a single radial link to an on-shore connection point. By considering all transmission links both off- and on-shore with the expected sequence of off-shore wind farms, radial links can in some cases be replaced by links connecting several wind farms. NGESO (2022)'s *Holistic Network Design* (HND) for offshore wind examines the case for looking at the benefits of multi-farm links. The HND claims that while the offshore transmission costs would increase from £24.4 billion for the optimised radial design to the recommended integrated design of around £32 billion, the resulting on-shore reinforcement and re-dispatching costs of £21.7 billion would be £13.1 billion cheaper than the alternative, giving a net saving of £5.5 billion. The total optimised cost for connecting 50 GW of offshore wind by 2030 is roughly £54 billion (i.e. £32bn. + £21.7bn.), so the saving is 9% of the alternative. Another way of looking at this is that the average network cost of the off-shore wind is £$_{2022}$1,008/kW compared with wind farm itself of £$_{2018}$1,630/kW (£$_{2022}$1,873/kW). Beatrice's OFTO cost £$_{2021}$438 m. or £$_{2022}$812/kW (but this excludes on-shore reinforcements financed from G-TNUoS).

While this saving of 7% from the holistic multi-function link on and off-shore network design is worth having, the proposed links involve substantial volumes of offshore HVDC links ("bootstraps"), and raise obvious concerns about asset-biased solutions. Moreover, the HND is silent on optimizing the clearly cheaper on-shore wind, currently not allowed to participate in the renewables auctions for political reasons (although the latest policy statement (HMG, 2023, p23) claims "Recognising that onshore wind is an efficient, cheap and widely supported technology, Government has consulted on changes to planning policy in England for onshore wind to deliver a localist approach that provides local authorities more flexibility to respond to the views of their local communities".

The aim of optimising assets should include ensuring that the location of generation and supporting network expansion assets are *jointly* optimised, and that their dispatch is also at least cost. NGESO (2022)'s *Holistic Network Design* for off-shore wind shows the benefits of considering the totality of off-shore wind developments in an integrated way, planning both on- and off-shore to minimise transmission costs (investment and avoided congestion) to connect the committed off-shore wind farms. However, this is a long way short of minimising total system costs, which requires more on-shore wind, where the network needed will depend sensitively on where these on-shore wind farms are located and how they are dispatched.

7. Conclusions

Britain provides useful lessons on regulating transmission tariffs, setting transmission fees to improve location signals for investment, and moving towards more holistic planning of the network, at least offshore. As the leading offshore wind country in Europe she can also provide insights into the allocation of sites and the regulation and even coordination of offshore transmission investments. In the early years of the unbundled liberalized market, the main challenge lay is encouraging the new entrant gas-fired generation to locate where there was adequate export capacity on the existing networks, as it is cheaper to move gas to the power station than to move electricity a comparable distance to load centres. National Grid combined setting quite strongly zonally-differentiated annual network tariffs for generation and load with seven- and then ten-year statements providing directions on where new generation should connect. Most European countries lacked sharp location signals, but this may not have been of much concern before they needed new capacity, and in many countries gas generation was either already widely used or not competitive against the existing more than adequate capacity, allowing business to continue as usual.

The EU *20-20-20 Renewables Directive* (EU, 2009) pushed a massive expansion of renewable electricity, which needed to connect to networks in usually quite different locations than the existing fossil and nuclear fleet, imposing new stresses on transmission and distribution networks. Without suitable locational tariffs to connect to the network there was an evident danger, rapidly realized, that renewables, particularly wind, would locate in distant areas with weaker transmission links prone to congestion. Britain was slower to develop an efficient support mechanism, and its initial premium feed-in tariff amplified the benefits of locating in windy distant locations, considerably stressing the North-South link at the Scottish border. Eventually GB introduced renewables auctions allocating low-risk CfDs with auction-determined strike prices. As long as the support was provided to total metered MWh over 15 years at above market prices, the quite strong location signals sent by NGESO were, to a more or lesser extent, countermanded by the attractions of windy locations. A further problem is that the TNUoS tariffs were backward-looking and slow to adapt to the implications of increasingly predictable future generation entry.

The main lesson, therefore, is that renewables support systems and transmission tariffs both need to give efficient location signals at the time of entry. This is most simply achieved by offering suitable long-term transmission contracts at the point of investment, while not disturbing the tariffs on existing and immobile generators. There are simple changes to renewables support to improve their location choices, by limiting the contract to a fixed number of efficient hours (MWh/MW) not years, as the aim of support is to finance the initial investment with cheap debt. As at least on-shore investment costs are unlikely to vary much geographically there is no need to provide additional infra-marginal rent to investors in resource-rich locations.

The offshore wind industry has been remarkably successful by any standard, and has evolved a good model for onshore contracts. It is characterized first by an initial choice of suitable sites (in this case by the Crown Estate) that are auctioned off, and second by an efficient mechanism for financing and charging for the offshore transmission link to the mainland, offered in competitive auctions for 20-year contracts. This model of 20-year transmission contracts would seem suitable for on-shore connections.

Finally, Britain has unbundled the transmission ownership and system operation functions. If, as planned, the SO function is taken into separate state ownership, and combined with anticipatory and perhaps even proactive integrated network planning, the bias towards asset-heavy solutions may be overcome. Promising steps in this direction are already visible in the sequence of regulatory reforms to transmission, and the ESO's *Network Options Analyses*, *Holistic Network Design* and *Powering up Britain*.

Appendix A Illustration of forms of LMP

Figure A1 gives a five-node example to examine different market rules including LMP restricted to balancing/real-time and the full day-ahead central dispatch LMP. Nodes 1-4 have generators, each with capacity K_i, start-up cost f_i, variable unit cost c_i, delivering to the demand node H, where demand is 150 MW.
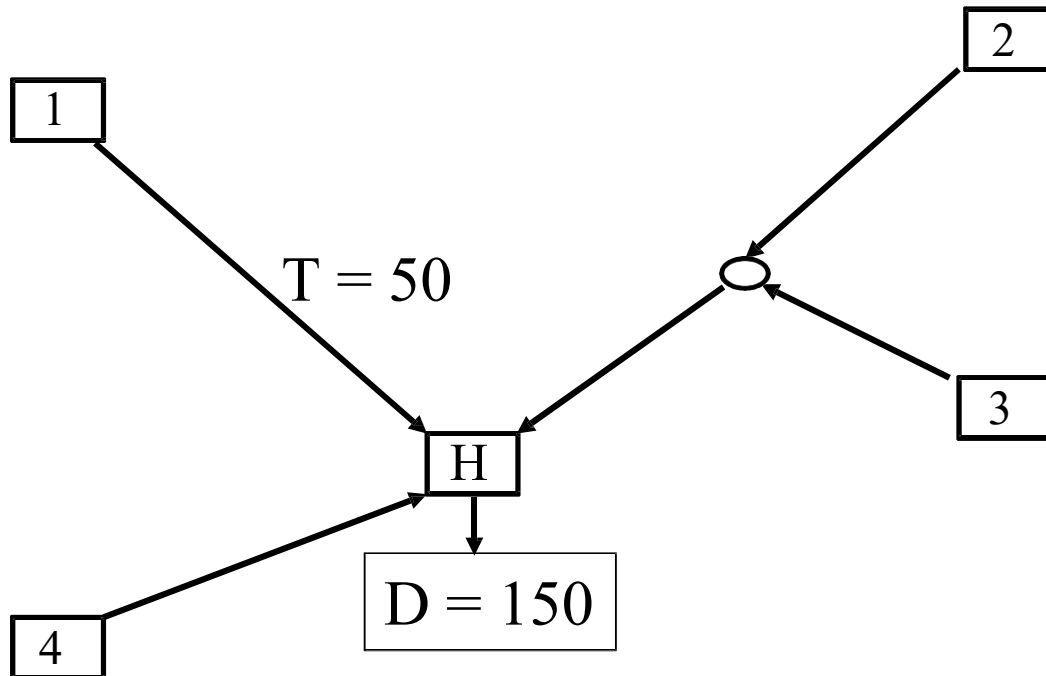

Figure A1 Network for nodal pricing options

All links but 1- H are unconstrained but 1- H has a capacity of 50 MW. To avoid problems of market power (whose extent will depend on available mitigation) all offers are assumed to be honest, while there is no uncertainty over the time considered (a day). Table A1 gives the generator cost details.

Table A1 Data and results of LMP variants

node	1	2	3	4	Total
K_i MW	100	40	100	55	295
f_i £	£200	£0	£200	£0	
v_i £/MWh	£20	£60	£80	£50	

The System Operator (SO) has to procure reserves ahead of time to satisfy the loss of the single largest link or generator (the N-1 constraint), which will depend on commitment, that is, which set of generators is available at short notice to meet unexpected failures. Thermal plant typically needs time to warm up and synchronise, and so commitment means that the plant is already spinning and synchronised well before it may be needed. To commit a plant involves incurring various costs even if not generating. Fast response generation and batteries can be called on closer to real time and may not require day-ahead commitment. The set of generators committed at the day-ahead (DA) stage depends on the market design.

Central dispatch plus LMP
The benchmark model to be discussed first in central dispatch at the day-ahead (DA) stage with a security-constrained optimal commitment and dispatch and full nodal (LMP) pricing. Table A2 gives the results for this case.

Table A2 Central dispatch and full LMP

node	1	2	3	4	H
LMP £/MWh	£20	£80	£80	£80	£80
Commit (1 if yes)	1	1	1	1	
dispatch MW	50	40	5	55	150
Energy revenue	£1,000	£0	£3,600	£4,400	£12,000
T congestion rev	£3,000	£0	£0	£0	£3,000
Total gen cost	£1,200	£0	£3,800	£2,750	£6,950
Energy profit	-£200	£0	-£200	£1,650	£1,250
Make-good	£200	£0	£200	£0	£400
final profit	£0	£0	£0	£1,650	£1,650
Cons exp-T rev	£9,400				

The optimal dispatch is shown in line 3, where the cheapest generator G1 is committed (indicated in line 2 by 1) but only 50 MW can be dispatched because of the transmission constraint on line 1-H. The LMP at node 1 is therefore G1's SRMC, £20/MWh. The next cheapest source is G4, which runs at full capacity (and so cannot set the price), followed by G2, also at full capacity. G3 delivers 5 MW to make up total demand of 150MW and sets the LMP on unconstrained links at its SRMC of £80/MWh. All generation is committed, the required reserve is 55 MW (the largest generator G4) and that is automatically available from the committed G3. Generator energy revenues are LMP x dispatch, their costs are unit cost x dispatch plus any fixed cost, and energy profit is energy revenue less cost. Fixed (start-up) costs may or may not be covered by infra-marginal rent (i.e. receiving an LMP above SRMC), but if not then make-good payments are made by the SO and collected from consumers. Congestion rents are the difference in LMPs across a link and accrue to the SO for later transfer back to consumers, whose total cost is shown in the last line (made up of energy revenue to generators, make-good payments, less any profits from congestion revenues).

Self-dispatch plus LMP balancing
This is the closest to the current market design except that the SO sets LMPs for all balance-responsible generation in the balancing market (BM), and also procures adequate commitment at the DA stage by paying any necessary fixed costs. The DA market clears at a price that sets supply equal demand ignoring all constraints (which will be resolved in the BM). The two cheapest generators, G1 and G4, set the DA price at G4's SRMC of £50/MWh. Table A2 shows the offers into the DA market and the resulting DA price. The N-1 contingency at this stage is therefore G1 of 100MW, so the SO commits (and pays fixed costs) to G3 (hence the 1 in line 2 under node 3).

Table A2 Energy-only day-ahead market and LMP balancing

node	1	2	3	4	H
DA offer MW	100	0	0	50	150
Commit	1	0	1	1	255
final dispatch MW	50	0	45	55	150
DAM price	£50	£50	£50	£50	£50
DA rev	£5,000	£0	£0	£2,750	£7,750
cost	£2,200	£0	£200	£2,500	£4,900
profit	£2,800	£0	-£200	£250	£2,850
Make-good	£0	£0	£200	£0	£200
final profit	£2,800	£0	£0	£250	£3,050
BLMP	£20	£80	£80	£80	£80
SO rev	£1,000	£0	-£3,600	-£400	-£3,000
G extra BM profit	£0	£0	£0	£1,650	£1,650
total G profit	£2,800	£0	£0	£1,900	£4,700
Cons exp	£10,750				

At the DA stage G1 will book £5,000 energy revenue against expected energy and fixed costs of £2,200, needing no make-good payment and clearing a DA profit (from its contract position) of £2,800. At the balancing stage the SO will constrain back G1 to 50 MW and G1 will buy back the 50 MW constrained down at its SRMC, making no profit on this action (if it had claimed its unit energy cost as £10/MWh it could have bought back the 50 MW for £500 while saving variable costs of £1,000). To make up the shortfall from constraining down G1, G4 is increased to its full capacity, leaving G3 to make up the shortfall and set the LMP at its SRMC of £80/MWh (shown as BLMP). The SO has to collect the extra cost of replacing the cheaper constrained-down generator by the more expensive replacement and charge it to consumers, whose cost under this system is appreciably higher than under central dispatch, while generation profits are higher. In resource terms, however, central dispatch is £950 cheaper than the energy-only system when including the extra redispatch cost of £3,000 to the generator costs of £4,900, compared to £6,950 under central dispatch.

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Glossary

BETTA	British Electricity Trading and Transmission Arrangements
CCGT	Combined Cycle Gas Turbine
CEGB	Central Electricity Generating Board
CfD	Contract for difference
CPI	Consumer Price Index
CUSC	Connection and Use of System Code
DNO	Distribution Network Owner
E&W	England and Wales
ESO	Electricity System Operator
FiT	Feed-in Tariff
LCOE	Levelized cost of electricity
LMP	Locational Marginal Price
MITS	Main Interconnected Transmission System
NETA	New Electricity Trading Arrangements
NG	National Grid
NGET	National Grid electricity transmission (company)
OWF	offshore wind farm
RAV	Regulated Asset Value
RIIO	Revenue using Incentives to deliver Innovation and Outputs
RPI	Retail Price Index
SMD	Standard Market Design (optimal security constrained dispatch with LMP)
SO	System Operator
SPT	Scottish Power Transmission
SSEN	Scottish and Southern Electricity Networks. SSEN Transmission is the trading name for Scottish Hydro Electric Transmission.
TNUoS	Transmission Network Use of System
TO	Transmission Owner
TSO	Transmission System Operator
WACC	Weighted Average Cost of Capital
VRE	Variable Renewable Electricity (e.g. wind, solar PV)