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Reform wholesale electricity pricing before the next crisis

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Introduction

British consumers of electricity, households, businesses, and institutions were facing months of energy hell before the new government's decision to cap household energy bills at an average of £2,500 per year from October 1. The proposed support package to alleviate energy inflation for businesses has yet to be fully announced, but it is equally important. Households contain voters, but businesses will have to deliver the government's new economic growth priority. Politicians across Europe including the UK have been dishing out many populist solutions to the energy crisis– abolish green levies, freeze household energy bills, remove VAT, restart fracking, increase gas production in the North Sea, reopen coal mines, windfall taxes on oil and gas companies, but none of these are compatible with net-zero targets. All are short-term to promote the idea that politicians are doing something to ease the energy cost-of-living crisis before a move to the promised land when electricity is generated mainly by renewables at close to zero marginal cost and the country's energy sources are also secure from international conflicts.

If this policy of freezing the price cap had not been introduced the Office of Gas and Electricity Markets (Ofgem), the energy regulator, predicted that from October the typical household gas and electricity bill could have risen by 75% from £1,971 per annum in April to £3,549. Before the government's intervention industry forecasts were suggesting a further doubling by next Spring.[1.] It is well understood that the major cause of rising energy bills is soaring gas prices, due to Russia's use of energy as a geo-political weapon complementing the trend expansion in the demand for gas as a temporary decarbonization stop-gap (See Stagflation and Net Zero[2.]), but there is little transparency in the government's plans. The Institute for Fiscal Studies (IFS), a think tank, has suggested that the proposed intervention is inefficient and untargeted and could cost taxpayers somewhere between £60 to £100 billion in the next twelve months based on 2019 consumption levels.[3.] However, neither these figures nor government estimates really add up. A crude analysis of the proposed price cap based on the average household consumption of electricity alone of around 3.7 MWh of electricity shows that there is something seriously wrong with the regulated pricing mechanism and independent estimates of the taxpayer support needed, although the government is reluctant to provide a figure.

1. https://www.cornwalllive.com/news/cost-of-living/energy-bills-more-5000-year-7449315
2. https://www.envirotech-es.com/economic-landscape/stagflation-and-net-zero
3. https://ifs.org.uk/articles/response-energy-price-guarantee

Making a very crude assumption that half of this consumption across the country is generated by renewables at an average cost of £48/MWh and another half by gas-fired generation at the inflated price of £446/MWh, ignoring other sources such as nuclear, and adding an appropriate mark-up produces a more realistic average electricity cost per household of £1,523 per year, 50% of what October's price cap would have cost and 61% of the government's announced price cap freeze. In Scotland, where renewables and nuclear accounted for a much higher proportion of electricity generated, over 80%, the difference between the price cap per household and the average cost of producing electricity [4.] is even greater. [5.]

Before the Russian-Ukraine conflict, many industry experts and economists realized that the price cap was inefficient, unnecessary, and based on 'arbitrary and implausible' assumptions of the strength of effective competition in the supply of energy by Ofgem.[6.] This regulatory failure resulted in supplier bankruptcies as gas prices edged upwards in 2021, but we go further and argue that the increased reliance on generating electricity from gas has had a major impact on the wholesale price of electricity and this would have broken the price cap eventually even if the war in the Ukraine had not happened. The rise in the significance of gas in the UK was due to government policies that look problematic in retrospect: running down nuclear, phasing out coal and the over generous subsidization of investment in renewables with a marked underinvestment in storage capacity.

In this paper we argue that the United Kingdom is evolving from a hierarchical vertical linear electricity system to a decentralised complex system. However, as the electricity system's structural complexity increased, there has been no attempt to modify a broken regulatory system where the politically sensitive price-capped retail price for energy is based on distorted national wholesale prices which no longer reflect actual local market supply or demand conditions for electricity nor provide the correct market signals necessary to attract investment to meet net-zero targets. In this respect, a more significant announcement by the government before the price support measures was the decision by Kwasi-Kwarteng, now Chancellor, to review the current operation of electricity markets,[7.] with proposals to be submitted to the Department of Business Energy and Industrial Strategy (BEIS) on the Review of Electricity Market Arrangements (REMA) by October 10. In this respect we explore the implications of scrapping the current price cap completely based on a national wholesale market price and moving to market based zonal or nodal local wholesale pricing systems that reflects the system's growing complexity. Reforming national wholesale pricing will take the political pressure out of electricity prices and allowing targeted assistance to tackle fuel poverty while still encouraging investment that will facilitate net zero, reduce average prices and encouraging economic growth.

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4. https://www.scottishrenewables.com/our-industry/statistics
5. https://www.ovoenergy.com/guides/energy-guides/how-much-electricity-does-a-home-use
6. Steven Littlechild (2022) https://www.eprg.group.cam.ac.uk/wp-content/uploads/2022/01/S.-Littlechild_Retail-energy-market-consultation-response_-Jan-2022.pdf
7. Review of Electricity Market Arrangements (REMA)

An Evolving Complex Electricity System

The United Kingdom has moved steadily from a unidirectional electricity supply system, first vertically integrated under public ownership, then vertically disaggregated into generation, transmission, and distribution after privatisation, to an evolving multidirectional complex system. A complex system, in contrast, to a complicated system, has been defined as:

"...a system in which large networks of components with no central control and simple rules of operation give rise to complex collective behaviour, sophisticated information processing, and adaptation by learning and evolution." [8.]

The main difference between a simple system and a complex one is that in the latter economic agents change their behaviour and adapt to new situations and because of this central control becomes harder to enforce. The main argument of this paper is that the rise in the price of gas attributable to the invasion of the Ukraine has exposed the failings of a regulatory model designed for a simpler electricity system than the one currently evolving in the United Kingdom. According to a paper on complexity and electricity markets:

"Electricity markets have changed substantially and evolved into a complex system. When the regulatory model was designed, pollution was not a big issue. There were no solar panels installed on the houses of consumers. Many contemporary issues of the ecosystem of electricity were not relevant. Regulatory tariffs were modelled to cover the costs of the chain of supply by charging consumers for the amount of electricity they used." [9.]

The regulatory framework put in place and now administered by Ofgem takes account of both the electricity system's natural monopoly elements and its competitive characteristics to influence prices while fair rates of return are earned by shareholders to encourage[3] investment. Regulated tariffs, such as the United Kingdom's price cap which only came into effect as recently as 2019, are designed solely to cover the wholesale costs of the supply of electricity at a rate based on the amount of electricity used with an adequate mark-up. The demand for electricity with its seasonal and daily peaks and troughs is taken as given in the regulated pricing model, while in the UK the variable supply costs of generation and the grid-based Distribution Use of System (DUoS) and Transmission Use of System (TUoS) charges are all passed onto to the consumers of electricity in their bills.

8. Mitchell, M. (2009). Complexity: A Guided Tour. Oxford, Oxford University Press
9. Fuat Oguz (2021): Hayekian complexity and the role of regulation in electricity markets, Economic Affairs, Wiley

A regulated tariff, as a price for consuming electricity, should act as a market signal and should have an impact on the supply and to a lesser extent on the demand for electricity depending upon the degree of competition and the relevant demand elasticities. Unfortunately, in the design of static regulatory models for simple electricity systems it is, "generally assumed that there were no major unintended consequences ...that the behaviour of consumers or producers would not change during the implementation periods." This provides for a limited role for relative prices as market signals. As in most markets high electricity prices should encourage investment in the generation, distribution and storage of electricity while also encouraging efficient use and self-generation by households and businesses in the longer term. These mechanisms can be seen at work in the response to the oil price shocks of the 1970s which led over time to a protracted drop in the energy used to generate economic activity or the energy coefficient per unit of GDP.

The price cap employed in the UK subdues these market signals while the cost of subsidising renewable energy, passed on to consumers through a simple levy, on consumer bills completely suppresses them. The latter fixed and predictable element can be justified on market failure grounds, but in reaction to the current energy crisis the incoming UK government has decided to abolish the levy while capping the price cap in effect turning it into a poll tax on households and further emasculating any role in guiding the allocation of resources towards a complex system capable of delivering net zero.

The cost of high energy gas and electricity to households can be met by subsidies on social or income distribution grounds, but the incentive signals created by the rising cost and lack of national security of electricity generated by fossil fuels are being effectively neutered. This will slow down the transition to de-carbonisation and lengthen the period that gas prices will produce a rising cost of electricity, irrespective of the current tension between NATO and Russia. We will show that one major problem in most current regulatory frameworks is the use of the marginal cost of the supplier of the last MWh of power, gas in many countries, coal, or oil in others, to set a national wholesale price which is used by the regulator to set price caps with no consideration for the average national, regional, or localised cost of generating and supplying electricity. We will also show that this problem stems from the evolution of the electricity system, the growth of renewables and the difficulties of grid balancing without the parallel investment in transmission capacity and battery storage which would have been stimulated through adequate market signals, but which are suppressed by the current regulation of the retail price of energy faced by households and businesses.

Generation and the National Grid

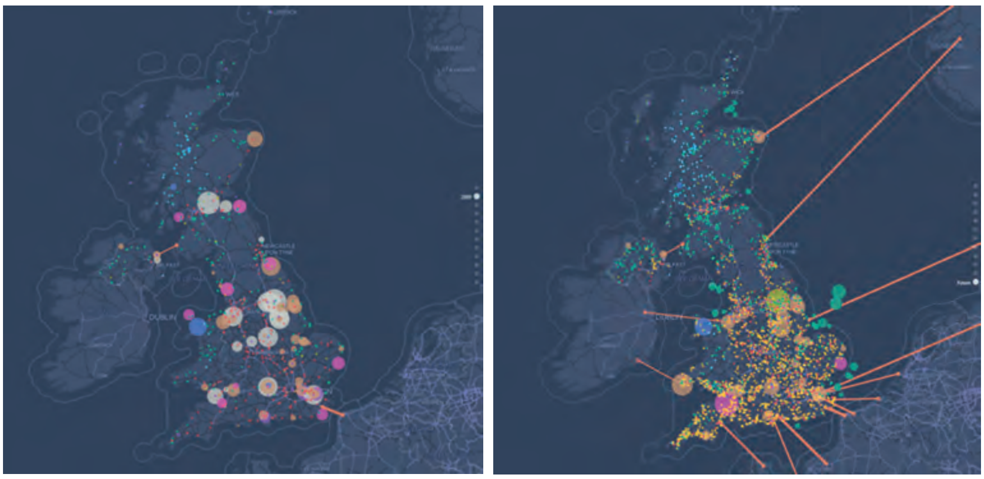
The concept of an electricity supply system based around a national transmission network in the United Kingdom dates to 1926 when a proposal to create a national high voltage single frequency network connecting the country's most efficient power stations. Prior to this centralisation the electricity supply system in the country was complex and had been plagued by many operators providing electricity at different currents and frequencies. In 1923, 109 generators only supplied Alternating Current (AC) voltages, 176 supplied AC and Direct Current (DC) and 207 supplied DC only. Of the 295 operators supplying AC, 76% distributed current at 50 Hz, but 82 undertakings which distributed current at a range of 17 frequencies from 25 Hz to 100 Hz, apart from 50Hz.[10.] The Central Electricity Board, set up by legislation in 1926, had the power to acquire supply at a constant voltage, 132 Kv, and a constant frequency, 50 Hz, from generators and distribute electricity along its regional transmission lines constructed between 1927 and 1936 to electricity suppliers. The system was initially decentralized into seven regional hubs,[11.] but after an unauthorized test in 1937,[12.] the network was connected effectively establishing a national grid. The grid eliminated one of the main inefficiencies of the relatively complex decentralized system that had grown since the late nineteenth century which was overcapacity created by wasteful competition.[13.] It has been estimated that connecting generators and distributors through a single source allowed spare capacity to be reduced from 80% to 15% by 1938 leading to a fall of 24% in generating costs.

The basic unidirectional nature of the national grid was reinforced and vertically integrated by the 1947 Electricity Act which nationalised generation and distribution until the privatisation of the industry from 1990 onwards. The system had sufficient excess generating capacity to react to supply and demand conditions and problems such as the rationing of supply and blackouts were generally caused by economic not technical issues such as the problems in sourcing coal supplies for generators in 1947[14.] and in 1973 during the national miners' strike which led to enforced blackouts and rationing.

10. Electricity Commissioners (1925). Electricity Supply - 1920-1923. London: HMSO. pp. xliii.
11. Glasgow, Newcastle, Leeds, Manchester, Birmingham, Bristol and London.
12. https://www.nationalgrid.com/about-us/what-we-do/our-history/history-electricity-transmission-britain
13. Electricity Council (1987). Electricity Supply in the United Kingdom: a chronology. London: Electricity Council. pp. 45, 54.
14. https://api.parliament.uk/historic-hansard/commons/1947/feb/13/fuel-and-power-cuts

However, regulatory reform and the policy of decarbonisation means that electricity systems across the developed world have been evolving into more complex systems, although at different rates in different countries, from unidirectional markets to multidimensional markets with interactions between participants flowing in several directions. In the UK the number of electricity generators has expanded significantly after the privatisation of the former nationalised companies. This has occurred in three phases: the upper tier of the non-domestic market for customers with a maximum demand of over 1 MW was opened to competition in March 1990. Then the 100 kW to 1 MW tier was opened to new suppliers in April 1994 and entry from new generators below 100 kW peak load was introduced in stages between September 1998 and June 1999. The number of generators classified as Major Power Producers (MPP) rose from 6 in 1990 to 36 by 2002.[15.] The most significant move towards complexity, however, has been the growth in the supply of electricity supplied by renewables – wind, solar PV, and bioenergy etc., which increased from 1.4% of total electricity generated in 2000, to 12.3% by 2010 and to 41% by 2020. In 2007, several large windfarms and solar PV producers were reclassified and the number of MPPs rose to 51 by 2015, but the number of smaller generators has also expanded rapidly. The growing number of electricity generators, large and small, but mainly based on renewables in the UK now exceeds over 2,000.[16.] The expansion in the number of renewable electricity generators (yellow is solar, blue is wind power) between 2010 and 2020 is illustrated in Figure 1, including international supply from interconnectors, which demonstrates the rise in complexity.

Figure 1 Increasing Complexity in UK Generation 2010 to 2020



15. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/556310/Electricity_competition.pdf
16. https://www.ofgem.gov.uk/sites/default/files/docs/2006/04/13537-elecgenfactsfs.pdf

Problems of Complexity

Complex electricity systems present regulators and energy policy makers with many issues. One problem is that complex systems, for technical reasons, are more vulnerable to power failures, such as brownouts [17.] and blackouts over wide areas than are unidirectional systems – a phenomenon known as cascading failure dynamics.

Second, the breakdown between the separation of supply and demand in unidirectional systems creates additional transmission costs in complex systems because of interdependencies between generators and consumers of electricity which are ultimately passed onto the latter. The subsidy regimes that have led to an overinvestment in renewables have been designed to meet their high capital costs while the lower operating costs in the face of rising wholesale prices are leading to windfall profits to some generators or the transfer of surpluses back to the state. They are not reducing the costs faced by consumers of renewable power which would incentivise support for a more rapid market-based decarbonisation.

Finally, the very success of incentives and subsidies to encourage the growth of power sourced from intermittent renewable energy, but not investing in grid-level storage, is increasing the congestion cost of grid-balancing, and passing additional costs onto consumers reducing the welfare benefits of renewable generation. Grid- balancing using a time-based wholesale national electricity spot price to pay generators to raise or reduce output leads to a further exacerbation of these problems and distorts the localised market signals needed to move to net zero. The task of a central controller using prices to adjust supply rather than demand will become increasingly costly and difficult as complexity evolves.

Cascading Failure Dynamics: One cause of power failures in complex systems is the rising interconnectivity of the network so that a fault in one area can rapidly expand and create contagion effects throughout the system. This is known as cascading failure dynamics which occur when "the failure of transmission lines during a blackout is determined not only by the network topology and by the static distribution of the electricity flow, but also by the collective transient dynamics of the entire system." [18.]

17. A brownout is a drop in voltage in an electrical power supply. The term brownout comes from the dimming experienced by lighting when the voltage sags. Brownouts can cause poor performance of equipment or even incorrect operation.

18. Scafer et al (2018): https://www.nature.com/articles/s41467-018-04287-5

In complex electricity systems severe outages are often started due to the failure of a single element in the system. On 9th August 2019, over 1 million electricity customers were hit by a major power disruption that occurred across England and Wales and some parts of Scotland. The power disruption was relatively short with all customers restored within 45 minutes, but the knock-on impacts on other services such as railways, hospitals and businesses were significant, inconvenient, and costly. The economic cost of the outage has been assessed at a minimum of £15 million.[19.] The immediate cause was a lightning strike to an overhead transmission line and the near simultaneous loss of a few generators at approximately the same time.[20.] The last time there was a near simultaneous failure of generators occurred in 2008 when both the Sizewell B nuclear power plant and the Longannet coal-fired station in Fife went offline.

The complex system operated by the Electric Reliability Council of Texas (ERCOT) nearly succumbed to an entire system failure in February 2021. The transmission grid in Texas is effectively separated from other grids in the United States which means that power failures cannot be met from imports. Severe storms led to a near electricity infrastructure collapse because of the failure of several wind power generators and problems with deliveries of coal and gas which left more than 4.5 million households and businesses without power. Wholesale Electricity prices rose by 10,000% to a cap of $9,000 MWh as the utility regulator tried to bring more generating capacity online leading to windfall profits for Bank of America's energy contract trading desk.[21.]

There are several solutions to reduce such examples of extreme price volatility and technical failures in complex systems. Unfortunately, the mathematical and statistical modelling of complex electricity systems using cascading failure models after several decades of progress remains in its infancy, but as electricity systems evolve the issue is becoming increasingly urgent along with investment in the algorithms needed to operate 'smart grids'. These are technologies permitting a more responsive connection between power producers and consumers. The U.S. Department of Energy defines smart grids as "digital technology that allows for two-way communication between the utility and its customers." Special meters employed by consumers constantly monitor demand and supply while devices known as 'synchrophasors'[22.] monitor electricity flows through the grid in real time and permit operators to avoid disruptions. Decentralized "microgrids" are paired with grid-level battery storage allowing local power flows to continue communities even when the main power system is affected. Smart appliances shift electricity use to off-peak times, which eases the burden on the grid, ultimately lowering prices and avoiding blackouts.

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19. https://usave.co.uk/news/august-blackout-could-have-cost-more-than-initially-estimated/

20. Little Barford gas-fired station in Cambridgeshire, owned by German utility RWE, and the Hornsea wind farm off the coast of Yorkshire, owned by Danish company Orsted, both experienced system failures within two minutes of one another.

21. https://www.ft.com/content/321c4fb2-ca11-4e15-9ef5-05598dd04012

22. Synchronized phasors (synchrophasors) provide a real-time measurement of electrical quantities from across the power system. Applications include wide-area control, system model validation, determining stability margins, maximizing stable system loading, islanding detection, system-wide disturbance recording, and visualization of dynamic system response. The basic system building blocks are GPS satellite-synchronized clocks, phasor measurement units (PMUs), a phasor data concentrator (PDC), communications equipment, and visualization software.

Increased investment in energy storage which allows unused electricity to be stored and supplied at times different from when it is generated means that instead of power being wasted it can be used during periods of supply and demand imbalance. This will reduce the price volatility caused by extreme weather events, intermittent renewable power, and power outages. Storage investment is seen as the answer to the price volatility experienced complex electricity systems such as California and Texas. [23.]

Renewable Subsidies: The system of regulatory tariffs in unidirectional systems is based on a strict separation of supply and demand. Generators produce electricity which is supplied to transmission companies and distributors and consumers are charged for usage. The behaviour of customers and suppliers does not change so there are minimal feed-back effects. However, public subsidies for renewables have led to overinvestment by both consumers and producers, which although justified for climate change and energy security policies, have distorted market signals creating problems in evolving complex electricity systems through feedback loops.

For example, in the United States under net metering, utilities are required by regulators to purchase excess power back from solar users at the full retail rate of electricity. The growth in the use of solar PV and other forms of renewable energy generation and storage by households and businesses 'off-grid' means that grid costs are still shared among a smaller number of customers which will raise the average cost paid by customers providing an incentive for more of them to go off-grid and so on - a process known as the "utility death spiral." One analysis by the Rocky Mountain Institute, estimated that utilities in the Northeast of the United States could lose up to $15 billion by 2030 as customers switch to solar power. [24.]

The market design and the regulation of the electricity market in Britain after privatisation were based on the perceived need to encourage greater competition between market participants, generators, and distributors and not on the need to meet decarbonization targets. The later encouragement of investment in renewables in the generation of electricity was handled separately by subsidies justified on market failure grounds in order that renewable operators were able to recoup the high initial capital costs in the face of lower electricity prices.

23. https://www.stem.com/mitigating-price-volatility-in-ercot-with-smart-energy-storage/

24. https://www.cfr.org/backgrounder/how-does-us-power-grid-work

The UK's renewable subsidies have encouraged the use of renewables with relative success, but again by distorting market signals which have increased the complexity and price volatility of the electricity system without parallel stabilising investment in storage.[25.] To encourage small-scale renewable generation by households and businesses the government introduced the Feed-in-Tariff (FIT) scheme in 2010 which guaranteed purchases of excess electricity from accredited generators by electricity suppliers at rates sufficient to produce a return on investment for generation up to 5 MW of different forms of renewable electricity. The FIT scheme remained in place until April 2019 when it closed to new applicants and had resulted in an increase in aggregate renewable capacity of 3,567 MW after the first five years of operation or 682,511 installations, the vast majority of which, nearly 99%, were solar installations.[26.]

Support for large-scale renewable projects was initially provided by the Renewables Obligation (RO) which came into effect throughout the UK in 2002[27.] It placed an obligation on electricity suppliers to source an increasing proportion of their energy from renewable sources, but it closed to new generating capacity in 2017 although generation under the scheme was to last for 20 years. Accredited renewable generating stations received tradable Renewables Obligation Certificates (ROC)s for the eligible renewable electricity they generated, and this acted as guarantees allowing suppliers to meet their clean energy purchasing obligations. Since 2002, the percentage of the UK's electricity generated from low carbon energy increased from 1.3% to 23.5% and until the scheme's closure more than 23,500 generating stations with 25GW of installed capacity received accreditation under the scheme including 9.3 GW of onshore wind, 5 GW offshore wind and 5.3 GW of solar PV. This system has been progressively replaced by a different subsidy regime introduced because of legislation in 2013 with the intention of supporting the generation of low carbon generation – renewable projects more than 5 MW and nuclear power.[28.] Reverse auctions are held for projects and successful low carbon generators are awarded Contracts for Difference (CfDs). These are designed to provide stability for generators and reduce uncertainty for investors by ensuring that generators receive a fixed, pre-agreed price for the low carbon electricity they produce during the 15 years the contract is running. Generators of renewable plants over 5 MW were able to choose between RO and CfD support schemes until the end of March 2017.

25. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/456181/FIT_Evidence_Review.pdf

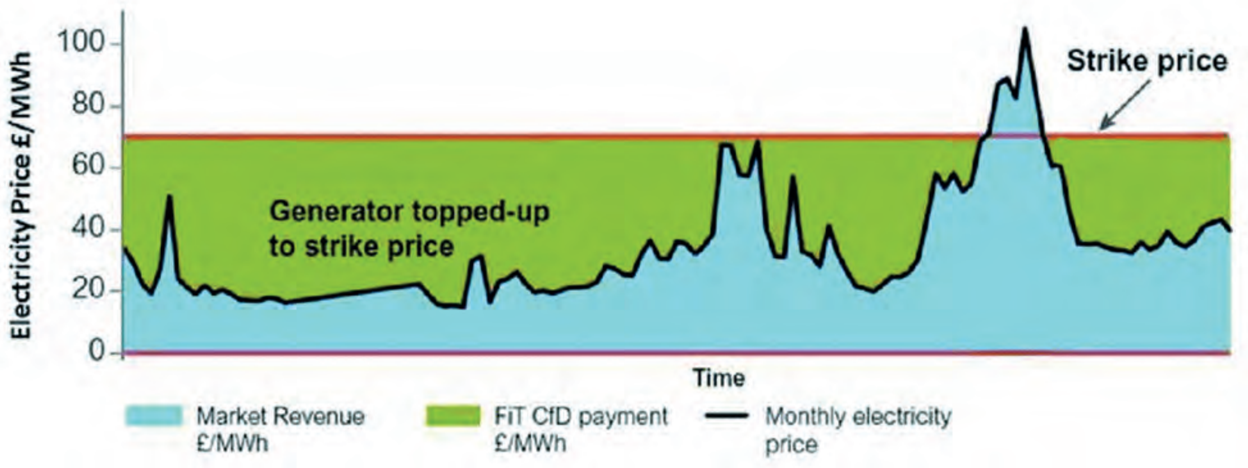
26. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/456181/FIT_Evidence_Review.pdf

27. Apart from Northern Ireland when it came into effect in 2005

28. The Energy Act 2013

Payments to generators depend on the market price for electricity generated and the fixed agreed price or 'strike price'. Generators sell electricity as usual to suppliers at the market price, but the CfD system uses a reference price based on the average market price. If this is below the strike price top-up payments are made to the generator by the Low Carbon Contracts Company (LCCC), which is wholly owned by the government, but if the reference price of electricity is above the strike price, the low carbon generator pays the LCCC the difference. This is shown in Figure 2

Figure 2

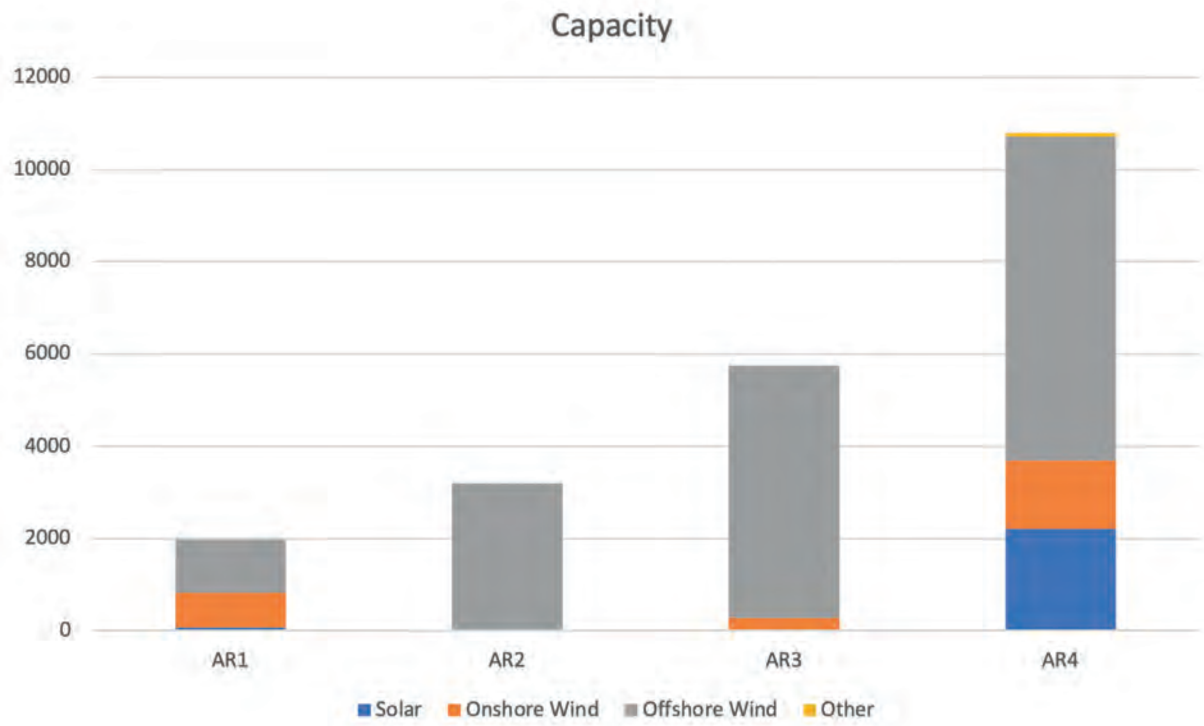


Renewable generators located in the UK that meet the eligibility requirements can apply for a CfD by submitting bids in auctions of which there have been four allocation rounds, to date – AR1, AR2, A3 and A4. The low carbon technologies eligible to win a contract in the CfD scheme are: onshore and offshore wind, solar PV, geothermal parts, hydropower, ocean power (tidal and wave), landfill gas, sewage gas, anaerobic digestion, biogas, biomass and CHP plants. The CfD scheme has been relatively successful in expanding the UK's low carbon generation capacity with the four rounds awarding contracts to projects with a total generating capacity of 21.7 GW of which most is offshore wind at 78%, followed by onshore wind at 12%. Furthermore, the average strike price for the projects awarded contracts has declined from £102 MWh in AR1 to £41 MWh in AR4, well below the current wholesale price of electricity and this gap is unlikely to change after the fifth round, AR 5, opens in March 2023.[29.] See Figure 3.

29. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/456181/FIT_Evidence_Review.pdf

However, this subsidy to encourage investment in renewables has increased the complexity of the electricity system while doing nothing to tackle feed-back effects between supply and demand nor to help stabilise price volatility through encouraging investment in storage. In fact, it has exacerbated the problem of grid balancing (see below)

Figure 3



The government has claimed that the reduction in costs to the consumer due to the CfD projects auctioned in AR1 and AR2 were estimated at around £3bn up to 2050 (in present value terms), compared with the RO policy that preceded it. However, the subsidy is funded by a statutory levy on UK licensed suppliers by a Supplier Obligation which allows the LCCC to make payments to CfD generators under CfDs, apart from payments under prior investment contracts. In addition, the operating costs of the LCCC are funded by another statutory levy on all UK-based licensed electricity suppliers (Operational Costs Levy). These costs are passed onto consumers, but the difference between the payments to CfD generators and wholesale prices caused by the increasing complexity of the system and rising gas use and gas prices is retained by the government which means that if wholesale electricity prices remain elevated for some time the scheme will be effectively subsidy free.

Grid Balancing: Grid balancing or maintaining the balance between the supply and demand for electricity, becomes more difficult and costly the more complex the electricity system and the greater the amount of generation provided by intermittent renewable with low utilisation rates sources such as solar PW and wind power. In any electricity system an Electricity System Operator (ESO) carries out the task of grid balancing. In the UK, in 2019 the ESO became a legally separate part of the National Grid and in April 2022, in discussion with Ofgem agreed to become the Future Systems Operator (FSO) to plan [30.] necessary future network investment as part of co-ordinating the government's decarbonisation policies for 2035 and net zero by 2050.

The ESO is responsible for balancing the supply of generation against demand to protect the system from technical failure if the frequency rises above or below 50 Mhz. For example, in the 2019 power failure in the UK, discussed above the total generation lost from the affected power stations was around region of 2,100MW, over twice the response capacity in the system causing the system frequency to drop below 48.8Hz. This triggered an automatic protection system which disconnected approximately 973MW of demand to stop the fall in frequency.

Outside of system failures routine demand and supply issues occur because there are physical constraints to the amount of power that can be carried across the network and congestion can arise when there are imbalances in relation to the need to operate system equipment safely and securely. For example, a high output of wind power in Scotland and the north of England may be flowing through the network to meet demand in the south and if the transmission network cannot meet this flow safely then it hits a constraint. The ESO resolves the congestion that arises by 'redispatch' or by instructing select generators and/or loads to change their schedule and pays them constraint costs. There are two types of constraint costs: some generators are paid to reduce or constrain their output while others are paid to turn up output. The ESO buys or sells electricity at the spot wholesale market price [31.] to constrain generation. This price is based on the marginal cost of generating the last MWh to ensure real time equilibrium to eliminate these imbalances between supply and demand across the system. This price is highly volatile during the day and over time and can even turn negative or rise to an exorbitant level. For example, on July 20, 2022, during a heatwave the ESO paid £9,724.54 price per MWH for balancing power between noon and 1:00 pm via the NEMO interconnector that links the UK with Belgium. This compares with an average spot rate of electricity of £178 MWH from January to July of this year.[32.]

30. https://committees.parliament.uk/writtenevidence/108430/pdf/

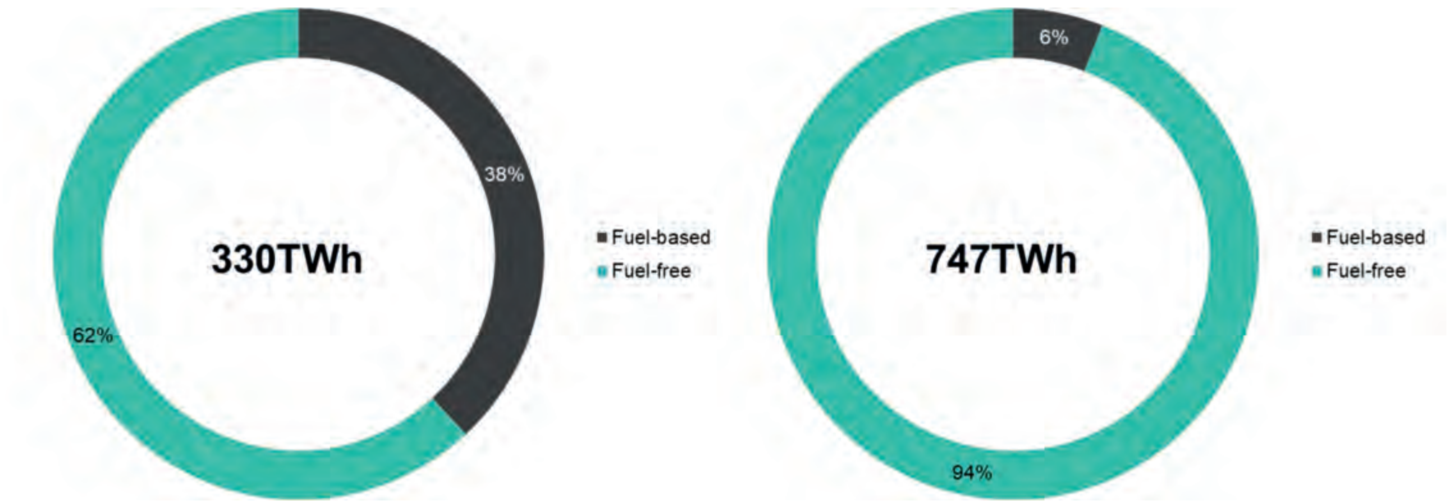
31. In the UK, electricity generators and suppliers' contract on spot markets or bilaterally and the current electricity market design is termed the British Electricity Trading Transmission Arrangements (BETTA) based on the New Electricity Trading Arrangements (NETA) created in 2001.

32. London's Record £9,724.54 per Megawatt Hour to Avoid a Blackout - Bloomberg

The success of the investment in renewables with intermittent supply generating electricity in regions geographically different from where most of the demand is has led to increasing problems. In recent years, the ESO has been managing an increasing proportion of balancing trades in part due to the rising volumes of intermittency on the system. The National Grid estimates that constraint costs are running at around £0.5 billion per year currently from around £167 million in 2010, but congestion cost may reach a net present value of £2.5bn in 2025, if planned renewable generating capacity comes online prior to the timing of the required despite an estimated £16bn of additional transmission investment over the next 20 years. These central costs are ultimately passed onto consumer bills.

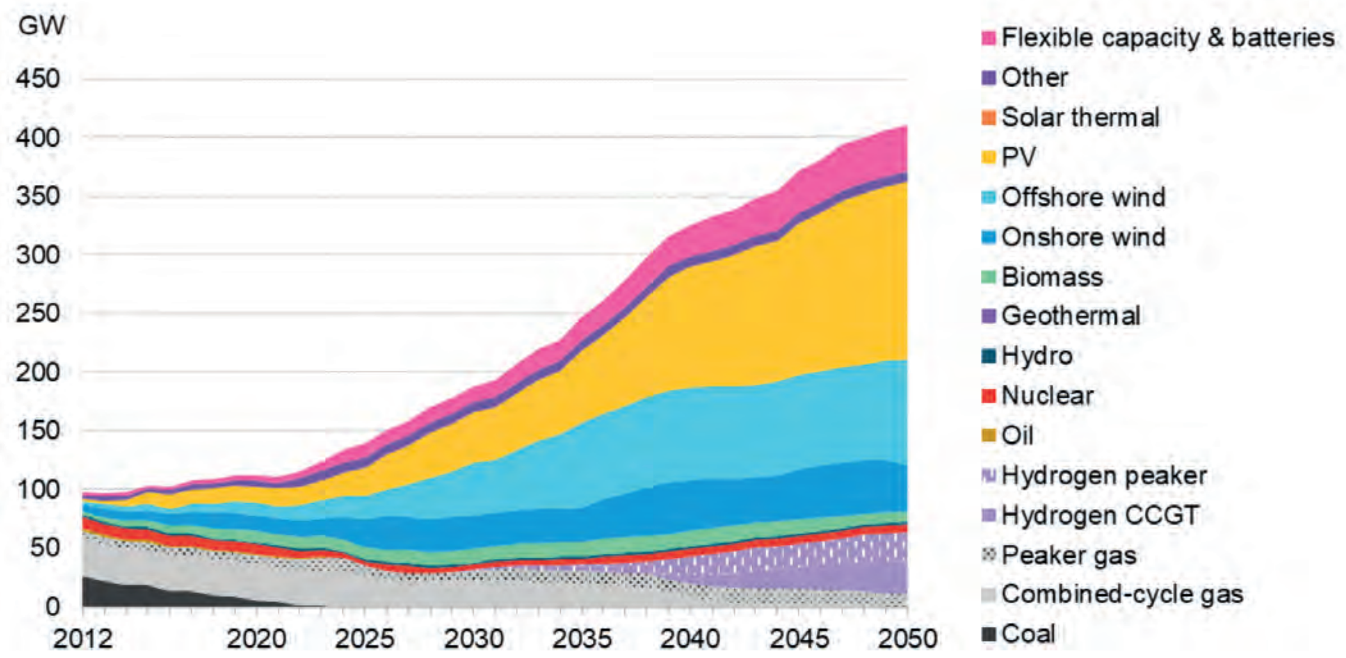
Irrespective of the price of gas in the coming decades, plans to expand the supply of electricity generated by renewables and the role of energy consumed powered by electricity, grids will face rising congestion costs as decarbonisation proceeds and there is an increased electrification of transport, heating and construction. It is estimated that the output of electricity will have to rise from 330 TWh in 2020 to 747 TWh by 2050 to cope with the transition, Figure 4.

Figure 4



This will require a large investment in additional renewal generating capacity, but as capacity rises there will also have to be parallel spending on distribution and storage through the grid and locally in the UK and in many other countries. The IEA has estimated that global annual investment in standard and digital electricity grids will have to rise to around $800 billion per year between 2026 to 2030 from an annual average of $289 billion[33.] between 2016-to 2020 to meet net zero targets. In the UK, the proportion of electricity generating capacity required to be provided by renewables is required to rise rapidly by 2050 with a steady reduction in the use of gas, Figure 5. However, delays between the growth in the grid's capability to cope with more intermittent generating capacity and to allow multidirectional flows of electricity through subs-stations into the grid will impose rising costs in balancing the system.

Figure 5



33. https://www.iea.org/reports/smart-grids

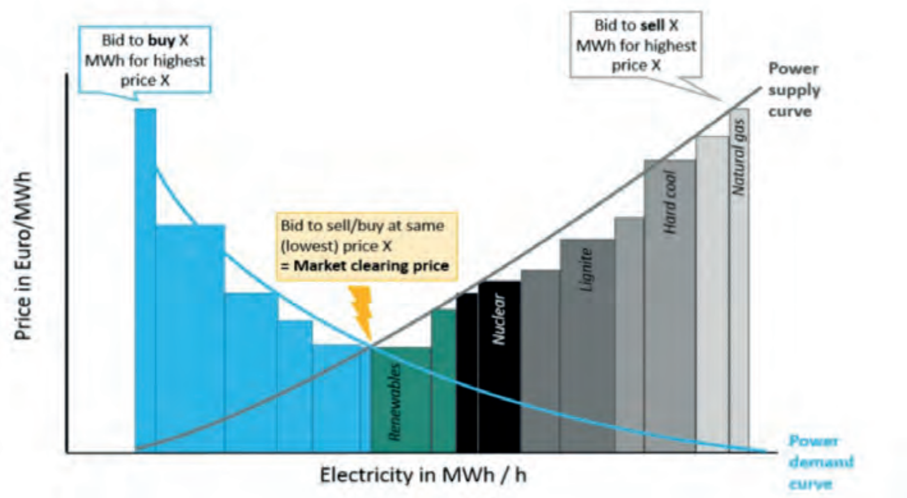
Wholesale Electricity Pricing

The determination of the wholesale price of electricity depends upon a combination of engineering and economic forces. Electricity markets around the world mainly use two types of congestion management methods to facilitate grid balancing: zonal pricing or nodal pricing. Some local electricity markets in the US and New Zealand employ nodal pricing, but European electricity markets favour zonal pricing where the size of the zone might be a region or a nation, as in the United Kingdom.

The announcement of the Review of Electricity Market Arrangements (REMA) in July 2022 recognises that the wholesale electricity market in the UK may need radical reform to ensure that the country maintains its path towards decarbonisation of the energy system while allowing consumers of electricity to enjoy the benefits of increased renewable generation capacity. The wholesale market has undergone three reforms since the privatisation of the 1980s: establishing the Electricity Pool of England & Wales; introducing the New Electricity Trading Arrangements (NETA) in the 2000s and the Electricity Market Reform (EMR) in 2013 which set up the CfD system for paying eligible renewable generators described above.

The NETA reforms were first proposed by Government in 1998 and implemented in 2001. In 2005, the British Electricity Trading and Transmission Arrangements (BETTA) were established, and it expanded NETA from England and Wales to Scotland, establishing a united national electricity market in Great Britain. The current electricity market in the UK is a self-dispatched (supplied by the generator) energy-only market that replaced the central dispatch mechanism of the Pool with the aim of encouraging competition among buyers and generators of electricity on principle of bilateral trading. All output of generators is required to be contracted either in the forward market or the spot market and the task of the ESO is to balance total contracted dispatches against demand every half hour. The marginal cost of producing different sources of energy differs significantly see Figure 6 based on a hypothetical European market which shows a power demand curve and power supply curve for renewables, nuclear, and fossil fuels with a rising marginal cost for fossils, although they have a higher utilisation factor and are more reliable (the cost of producing the next MWh of power). At the demand power curve shown there is a market clearing price where the bid to buy and the bid to sell are and at this point all the required supply is met by renewables. However, if the proportion of electricity supplied by renewables is high, but not sufficient to meet all demand, or as will increasingly become the case, marginal demand must be generated by a high-cost supplier such as gas because of the need to balance the grid because of congestion, the wholesale spot price is set by the marginal cost of the generator of the next MWh.

Figure 6

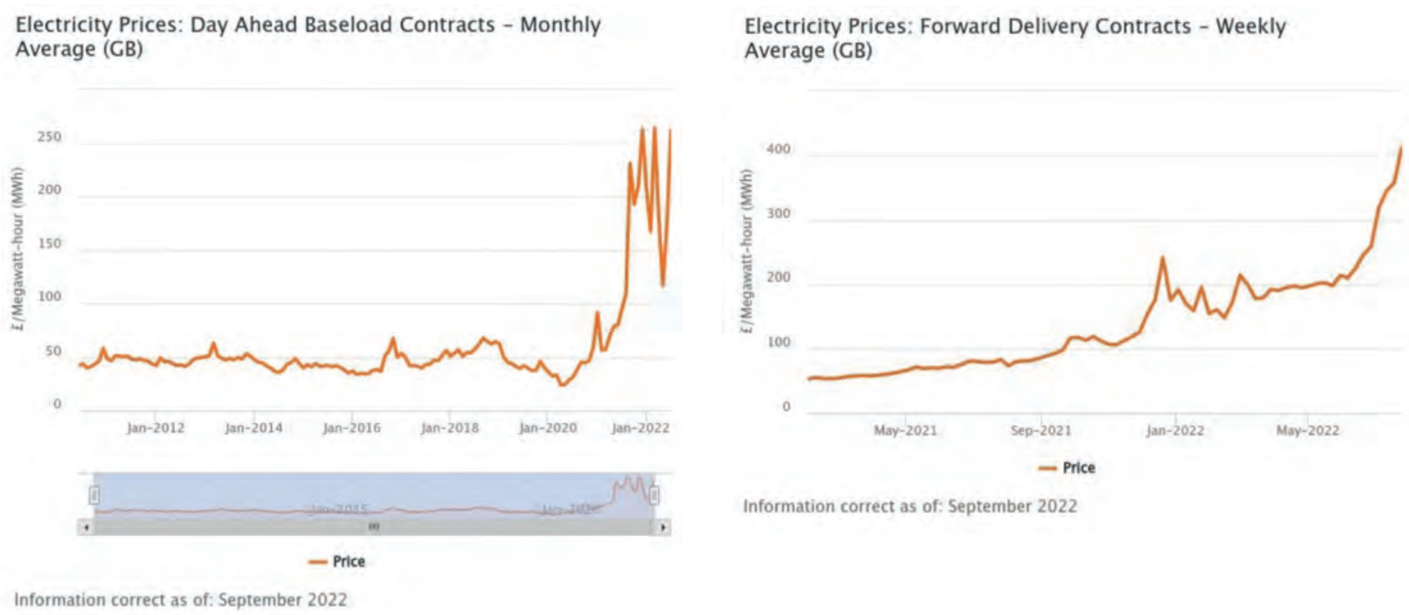


The role of the price of gas in determining the wholesale spot price of electricity is demonstrated clearly in Figures 7 and 8 which show the close correlation between the monthly average spot price of gas and the average day-ahead electricity prices from 2010 to 2020 with the sharp rise of before in 2021 before the Ukraine crisis. This correlation held despite the significant

Figure 7

Information correct as of:September 2022

Figure 8



National Pricing: [34] In some countries where the architecture of the electricity system remains vertical and largely unidirectional such as the United Kingdom, France and Germany, the wholesale market price is a single national price faced by all buyers and suppliers of power across the country at each moment in time. This is the equilibrium price deemed necessary to balance the electricity grid, which is supervised by the ESO, which is the responsibility of the National Grid in the case of the UK, a private company. In Germany, grid balancing is carried out through a system of cooperation between four regional transmission system operators (TSO) companies: 50 MHz, Tennet, Amprion and Transnet BW, but at a single national wholesale price. In France, a state-owned body,[35] Réseau de Transport d'Électricité, (RTE) operates the transmission network and interconnectors with neighbouring countries. RTE is responsible for balancing supply and demand and imports and exports of electricity. There is currently a project to introduce a Europe-wide integrated price coupling for the day-ahead market.

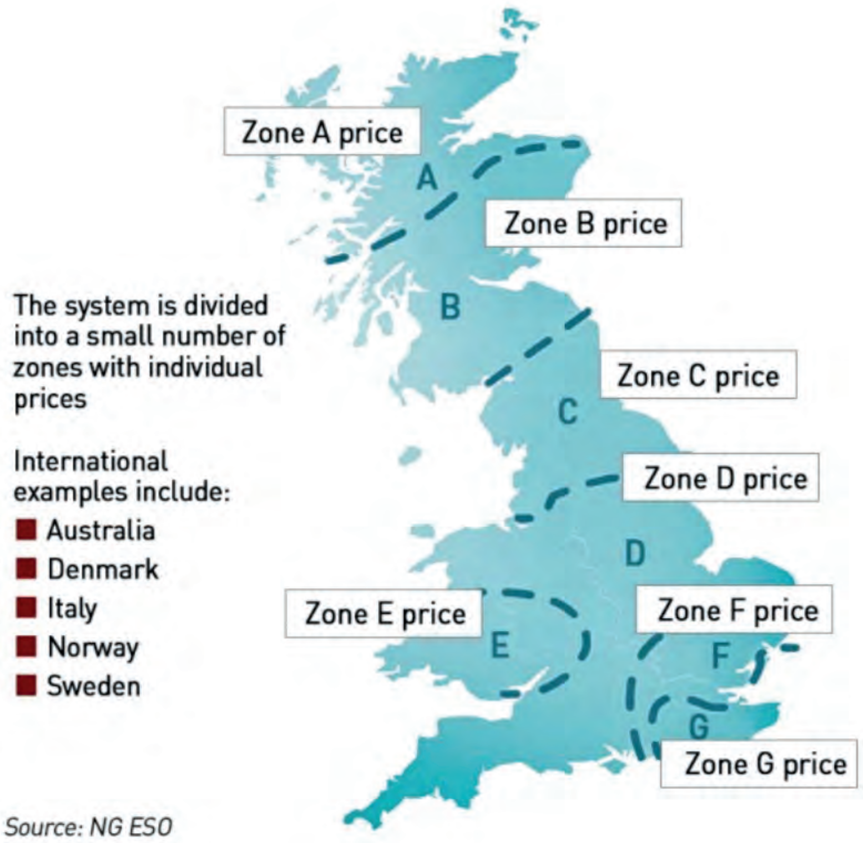
34. https://watt-logic.com/2022/07/18/locational-pricing/
35. RTE is owned by EDF and Caisse des Depots both public sector bodies

However, national wholesale market electricity prices can lead to inefficient short-run dispatch, [36.] effectively planned output at different prices by generators, as they are not incentivised nor provided with adequate information to consider transmission line limits when participating in the wholesale market. Trading at the national wholesale price neglects the problem of network congestion the larger the trading area. This can increase the congestion costs in the system leading to growing financial transfers from the ESO to consumers to constrained generators which leads to suboptimal dispatch. For example, in the UK, wind generation capacity is rising in Scotland, but the main areas where demand is increasing are in the southeast of England. As congestion rises a lack of investment in transmission capacity as the proportion of renewable generation increases, means that a large amount of wind generation must be constrained with the payment by the ESO of curtailment fees. This raises the costs passed on to consumers, but it is also inefficient because in the absence of large-scale storage this energy is lost.

Zonal Pricing: In a zonal electricity market, the grid is divided into several regions and wholesale electricity prices for each settlement period are cleared based on supply and demand within each zone. The number of separate wholesale prices equates to the number of zones. In Denmark, there are two zones while Sweden has four and Italy has seven. Transmission constraints on the boundaries of zones are reflected in differences in wholesale prices which in the short-term should provide market signals to electricity consumers to adjust demand and in the long-term to invest in additional generation and transmission capacity. The main defect of zonal systems stems from the question of choosing the optimal division into zones since market signals will not work effectively in solving intra-zone congestion. The National Grid has produced an indication of what the UK electricity market might look like with seven pricing zones with boundaries based on transmission constraints, Figure 9.

36. A short-run despatch schedule will be based on the sales price in relation to variable costs. Dispatch creates a schedule that determines the allocation of available capacity for the power plant. Plant operators usually register their schedule with the relevant transmission grid operator to allow forecasts of the grid's available power.

Figure 9
Hypothetical Zonal Wholesale Pricing



The UK maintains a national wholesale price, but effective zonal prices occur since cross-border wholesale prices vary from national prices because of the 6 GW of interconnector capacity with six countries France, Norway, the Netherlands, Belgium, Northern Ireland, and Ireland. Interconnectors receive congestion revenues resulting from price differences between national markets at either end of the interconnector grid link and can help export in the case of excess energy or import in the case of supply deficiencies. These market signals are encouraging a further investment of 7.5 GW in interconnector capacity planned between now and 2026, but to the extent that import prices differ significantly from national wholesale prices this will raise system costs if they are high or create congestion if they are low. Furthermore, a national wholesale price of energy does not promote efficient use of battery storage which should reflect local, not national, supply and demand imbalances if storage is to respond to short-term needs. [37.]

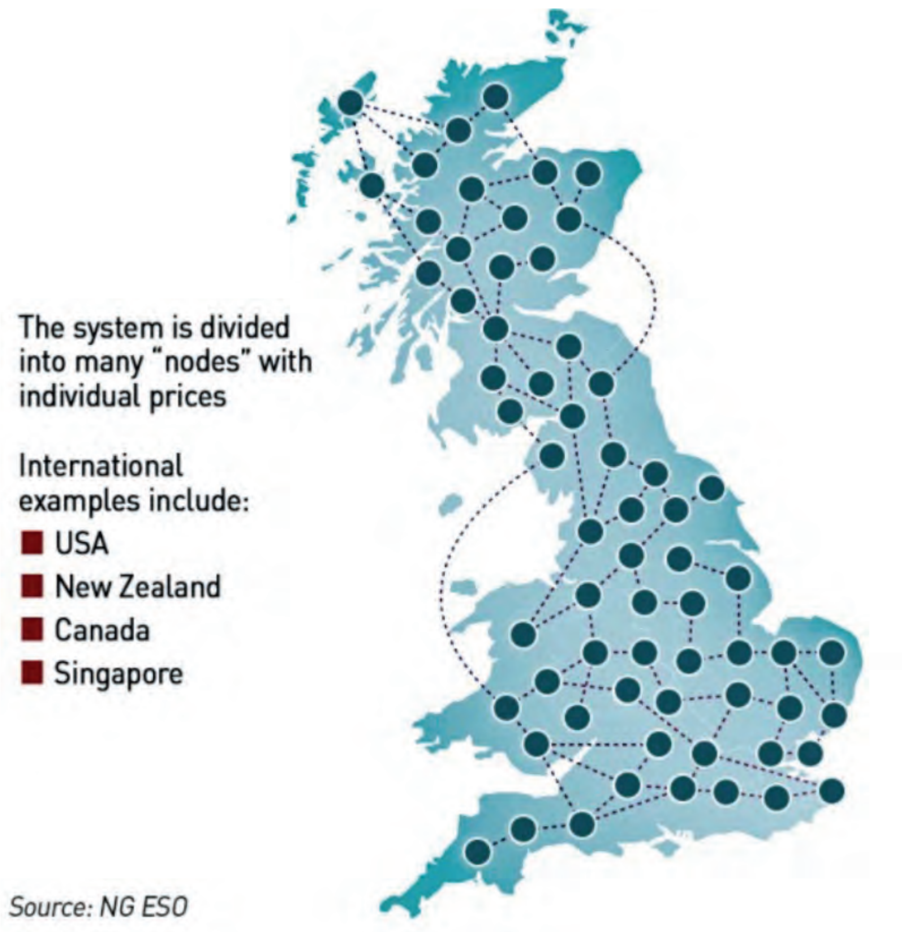
37. https://www.ofgem.gov.uk/energy-policy-and-regulation/policy-and-regulatory-programmes/interconnectors

Nodal Pricing: The National Grid ESO in a reform proposal in 2022 has come out strongly in favour of moving to a nodal system of pricing wholesale electricity in the United Kingdom.[38.] In a recent report [39.] the National Grid argues that the current electricity market design is "no longer fit for purpose for a rapidly decarbonising system… and if left unchanged, the current national pricing model will impose excessive and unnecessary costs on consumers." Nodal pricing systems exist in several electricity markets and have been gaining increasing support from academics in the discussions for the design and regulation of an integrated European electricity market.[40.]

Instead of aggregation into zones every generating point, distribution substation or transmission line intersection constitutes a node of which there are potentially thousands in a large electricity system. The electricity price at each node reflects the local cost of generation and delivery including network losses and congestion resulting in many different wholesale prices. Under nodal pricing, for example, at the same time of day a nodal price in the north of Scotland might be £10 per MWH while a nodal price in the south of England could be £90 per MWH. Compared to a national price where batteries and interconnectors can exacerbate constraints, in zonal and more so nodal pricing wholesale price signals are more accurate reflections of supply and demand conditions and would enable batteries and interconnectors to respond to price signals that support the system.

38. https://www.nationalgrideso.com/news/new-eso-report-finds-electricity-market-reform-critical-delivery-future-system-affordable
39. Net Zero Market Reform – Phase 3 Assessment and Conclusions
40. https://fsr.eui.eu/nodal-zonal-pricing/

Figure 10 Hypothetical Nodal Pricing



Conclusion

The UK is evolving into a complex electricity system with many interdependencies between the suppliers and consumers of power. One of the consequences of this system is that in the absence of a market based locational electricity market, the national wholesale spot price is dictated by gas producers that provide less than half of the country's electricity generated. Our analysis suggests this problem was in process well before the invasion of the Ukraine and is a consequence of the success so far of the decarbonisation of electricity generated in the last two decades. However, whatever happens to gas prices if Russia, NATO and the European Union come to an accommodation on energy supply, this problem will worsen as the push to generate more electricity from renewables to meet net zero is executed without parallel investment in storage which unlike renewables receives no subsidy.

The problem is a broken regulatory system where wholesale spot prices are determined by the marginal cost of the supplier of last resort and retail prices are based on a wholesale price plus charges and a mark-up. Without reform of the pricing system and a move to zonal or nodal systems there is no point in changing the regulation of the industry through Ofgem which is why the proposals by the BEIS are more important than the price cap support package in the long run. Furthermore, there is a lack of transparency about the real cost of this package and the ultimate cost to the taxpayer since selling electricity at £2,500 per household per annum is well below the average cost of generation even at the temporary astronomically high gas prices. So where is the surplus? Who is doing well? A great deal of media attention focuses on the big gas producers such as BP, but there are some older renewable generators and all the current nuclear power stations for which the wholesale price of energy is well above the cost of generation. Furthermore, although the CfD generators receive a fixed price, the difference between that and the wholesale electricity price, is returned to the state adding to the current assets of the LCCC. The price support package is unnecessarily large and is based on using the gas price to determine the wholesale price of electricity. The government is very unclear about the real cost of support, but as Boris Johnson's advice to his successor might be: "Never fail to make use of a good crisis."

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