Cost of Energy Review

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Preface and Acknowledgements

This review comes at a time of considerable public debate and concern about the increases in energy bills to customers, and about the ability to pay and the impacts on industrial competitiveness. It also comes at a time of huge technological opportunities and change, on a scale not seen in electricity since the late-19th century, which offers considerable optimism about the speed of decarbonisation and about the process being less costly than many have feared.

The review is not, and was never intended to be, a comprehensive summary of the views of the experts, professionals, energy businesses, customers, and the many vested interests that have grown up around the electricity industry. As in other heavily subsidised sectors, such as agriculture, interventions have become multiple, and with them has come a highly effective growth in lobbying.

I have resisted such pressures to the best of my ability. I have the great advantage of having worked with governments, companies and customers for over 30 years, from the initial liberalisation measures introduced back in 1982 through to the great privatisations, the reform of the wholesale markets in 2000, and Electricity Market Reform (EMR) in 2013. I have actively participated in the debates and discussions on all of these and published numerous papers and books, including most recently: *The Carbon Crunch: How We're Getting Climate Change Wrong – and How to Fix It* (2015), and *Burn Out: The Endgame for Fossil Fuels* (2017). The experience that comes from combining research with advising all the facets of the industry over this long period has yielded a deep knowledge base on how the industry and the government and the other parties work.

It is very important to point out that none of the companies or organisations I have had the privilege to work with is in any way responsible for the content and recommendations of this review, and this review does not advance any private interests. The analyses and recommendations are mine alone, and I am responsible for all and any errors that they may contain. This disclaimer applies especially to Aurora Energy Research Ltd, which I helped to found with a view to bringing the highest quality of energy research and analysis to the energy market. The views presented herein are not those of Aurora, and none of the many talented people in Aurora is responsible for, or has been privy to, this review.

I have set out a long-term framework for the electricity industry which will provide a stable and least-cost way to achieve the twin goals of meeting the Climate Change Act (CCA) and security of supply. This task is urgent not just because of the many failures of the current market, but also because of the pressing need to meet the new and exciting challenges ahead which will come with the digitalisation of the economy, electric transport, new storage, demand-side opportunities, and the development of decentralised energy systems. This new world stands on their head the current assumptions on which the industry is structured: the new world is likely to be more zero marginal cost and capacity-driven, rather than a marginal cost-driven wholesale energy market world; it will be dominated by a cornucopia of new data; and the old problems which have defined the industry structures – a lack of storage and passive demand – will gradually fade away. This is a fundamental break with the past.

In taking on this task it has been a great advantage to have had a limited period in which to produce this report. There are no new facts to discover. All the content presented is based on information in the public domain. With this mass of information available to me, it would therefore be extremely surprising, and indeed very worrying, if there were new crucial facts to discover. In any event, energy policy is not about facts: it is about setting objectives and targets and designing regulation and markets to achieve them.

I have had the benefits of the Competition & Markets Authority (CMA) report, 'Energy Market Investigation: Final Report' (June 2016); several reports by the Committee on Climate Change (CCC) – most notably, 'Energy Prices and Bills: Impacts of Meeting Carbon Budgets' (March 2017), and 'The Fifth Carbon Budget: The Next Step Towards a Low-carbon Economy' (November 2015); and the *Clean Growth Strategy* by the Department for Business, Energy & Industrial Strategy (BEIS) (October 2017). I have further had the advantage of the many publications of Ofgem, and BEIS (and its predecessor, the Department of Energy & Climate Change, DECC) has produced a wealth of material for me to draw upon.

In preparing this review I have been extremely well assisted by a BEIS team, led by Jeremy Allen. He has been a great help and support, and his team have displayed all that is great in the British civil service. Particular thanks go to Harriet Arscott, Thomas Willems, Adam Bell, Andrew Robertson, Charlotte Fleetwood, and officials across the Department. I have also received enormous support, from the CCC and Ofgem. Data and background information, set out in the boxes, charts and tables, all of which is in the public domain, has been provided by BEIS, the CCC and Ofgem, as indicated throughout. None of these organisations has been privy to drafts of the review.

I have benefited greatly from an excellent group of advisers: Richard Nourse (Managing Partner, Greencoat Capital LLP); Laura Sandys (Chief Executive, Challenging Ideas); Terry Scuoler CBE (Chief Executive, EEF: The Manufacturers' Organisation); Isobel Sheldon (Engineering & Technology Director, Johnson Matthey Battery Systems Automotive); and Nick Winser CBE (Chairman, Energy Systems Catapult). They have provided expert advice and have been a sounding board for a number of the ideas developed in this review. It is hard to think of an advisory panel better suited to this task. I should stress that they are not responsible for any of the content of the review, or its recommendations, and should not be assumed to have agreed with all or any of what is presented. Again, none has been privy to drafts of the review.

Finally, my intention has been to highlight what I regard as the failings of the current market framework and structures, and should not be seen as a criticism of any individuals or institutions.

Terms of Reference

The Terms of Reference of the review are set out below.

1. The government has the ambition for the UK to have the lowest energy costs in Europe, for both households and businesses.

2. The UK was the first country in the world to set a long-term, legally binding target for emission reduction. The Climate Change Act commits the UK to reduce emissions by at least 80% by 2050, and sets a framework for the setting of rolling five-year carbon budgets. Parliament has recently approved the Fifth Carbon Budget, for the period 2028–32, at a 57% reduction on 1990 levels.

3. The carbon targets need to be met, while concurrently ensuring security of supplies of energy, in the most cost-effective way. The rapid closure of coal, the ageing of the existing nuclear fleet, the intermittency of some renewables, the scope for demand management and new storage, the coming of electric vehicles and the timing of future nuclear capacity coming on stream will be taken into account in considering how best to meet the overall objective of system security of supply.

4. The specific aim of this review is to report and make recommendations on how these objectives can be met in the power sector at minimum cost and without imposing further costs on the exchequer. In that context the review will consider the implications of the changing demand for power, including from industry, heat and transport.

5. The review will report on the full supply chain of electricity generation, transmission, distribution and supply, and consider the opportunities to reduce costs in each part, taking into account the roll-out of smart meters and the work already under way to underpin the transition to a smarter energy system.

6. The review will set out options for a long-term road map for the power sector, and consider how technological change in the wider economy, as well as in the energy sector, may transform the power sector, and how energy policy can best facilitate and encourage such developments, consistent with the overall objectives of decarbonisation and security of supply, and with its *Industrial Strategy*.

7. The review will consider the options for enhancing and extending the scope for auctions and other competitive mechanisms, and for reducing the complexity across the full supply chain of electricity generation.

8. The review will consider the key factors affecting energy bills, including but not limited to energy and carbon pricing, energy efficiency, distributed generation, regulation of the networks, and innovation and R&D. The review will not propose detailed tax changes.

9. The review will focus on system issues and will not comment on the status of individual projects.

10. The review will provide recommendations as to how best to minimise the costs of energy consistent with the overarching objectives, taking account of the costs and benefits of the recommendations. It will set out options for developing and enhancing energy policy. Where the issues the review covers fall to other players, for example Ofgem, it will make recommendations about how government can best work with them to reduce costs.

11. The review will report at the end of October 2017.

Abbreviations

AI	Artificial intelligence
BAT	Best Available Techniques
BEIS	Department for Business, Energy & Industrial Strategy
BETTA	British Electricity Trading and Transmission Arrangements
CAP	Common Agricultural Policy
CAPEX	Capital expenditure
CCA	Climate Change Act
CCC	Committee on Climate Change
CCGT	Closed-cycle gas turbine
CCL	Climate Change Levy
CCS	Carbon capture and storage
CEGB	Central Electricity Generating Board
CEGE	Civil, Environmental and Geomatic Engineering
CfD	Contract for difference
CHP	Combined heat and power
CMA	Competition & Markets Authority
CMU	Capacity market unit
CPF	Carbon Price Floor
CPI	Consumer Price Index
CPS	Carbon Price Support
CRC	Carbon Reduction Commitment
CSCF	Cross-Sectoral Correction Factor
DECC	Department of Energy & Climate Change
DNO	Distribution network operator
DSR	Demand-side response
EBIT	Earnings before interest and tax
EBITDA	Earnings before interest, tax, depreciation and amortisation
EFP	Equivalent firm power
EMR	Electricity Market Reform
ETI	Energy Technologies Institute
ETS	Emissions Trading System
EUA	EU Allowance
EV	Electric vehicle
FIDeR	Final Investment Decision enabling for Renewables
FiT	Feed-in tariff
GHG	Greenhouse gas
IED	Industrial Emissions Directive
LCCC	Low Carbon Contracts Company
LCF	Levy Control Framework (umbrella term for all schemes: the LCF refers to *low-carbon electricity levy-funded schemes* covering CfD, RO and ssFiT)

LOLE	Loss of load expectation
LOLP	Loss of load probability
LPG	Liquefied petroleum gas
NETA	New Electricity Trading Arrangements
NIC	National Infrastructure Commission
NSO	National system operator
OCGT	Open-cycle gas turbine
OFFER	Office of Electricity Regulation
Ofgem	Office of Gas and Electricity Markets
OFTO	Offshore transmission owner
OPEX	Operational expenditure
PES	Public Electricity Supplier
PFC	Perfluorocarbons
PPM	Prepayment meter
PV	Photovoltaics
PWR	Pressurised water reactor
RAB	Regulatory asset base
RIIO	Revenue = Incentives + Innovation + Outputs
RMR	Retail Market Review
RO	Renewables Obligation
ROC	Renewables Obligation Certificate
RoRE	Return on regulatory equity
RPI	Retail Price Index
RSO	Regional system operator
SCC	Social cost of carbon
SMc	Smart Metering consumption
SMP	System marginal price
SRMC	Short-run marginal cost
ssFiT	Small-scale feed-in tariff
SVT	Standard Variable Tariff
TDCV	Typical domestic consumption values
TOTEX	Total expenditure
USO	Universal service obligation
VOLL	Value of lost load
WTO	World Trade Organization

Key Findings and Recommendations

1. The cost of energy is too high, and higher than necessary to meet the Climate Change Act (CCA) target and the carbon budgets. Households and businesses have not fully benefited from the falling costs of gas and coal, the rapidly falling costs of renewables, or from the efficiency gains to network and supply costs which come from smart technologies. Prices should be falling, and they should go on falling into the medium and longer terms.

2. Households and businesses have not benefited as much as they should because of legacy costs, policies and regulation, and the continued exercise of market power.

3. The scale of the multiple interventions in the electricity market is now so great that few if any could even list them all, and their interactions are poorly understood. Complexity is itself a major cause of rising costs, and tinkering with policies and regulations is unlikely to reduce costs. Indeed, each successive intervention layers on new costs and unintended consequences. It should be a central aim of government to radically simplify the interventions, and to get government back out of many of its current detailed roles. This review explains how to do this.

4. The legacy costs from the Renewables Obligation Certificates (ROCs), the feed-in tariffs (FiTs) and low-carbon contracts for difference (CfDs) are a major contributor to rising final prices, and should be separated out, ring-fenced, and placed in a ‘legacy bank’. They should be charged separately and explicitly on customer bills. Industrial customers should be exempt. Once taken out of the market, the underlying prices should then be falling.

5. The most efficient way to meet the CCA target and the carbon budget is to set a universal carbon price on a common basis across the whole economy, harmonising the multiple carbon taxes and prices currently in place. This price should vary so as to meet the carbon targets. It would be significantly lower than the cost of the current multiple interventions.

6. There should be a border carbon price to address the consequences of the UK adopting a unilateral carbon production target.

7. The FiTs and other low-carbon CfDs should be gradually phased out, and merged into a unified equivalent firm power (EFP) capacity auction. The costs of intermittency will then rest with those who cause them, and there will be a major incentive for the intermittent generators to contract with and

invest in the demand side, storage and back-up plants. The balancing and flexibility of markets should be significantly encouraged.

8. After all existing commitments in respect of FiTs and low-carbon CfDs have been fully honoured, and in the transition to a proper, uniform carbon price and an EFP auction, they should be split into three parts: the construction and project-development phase; the operation of the plant; and decommissioning. The first should have a higher cost of capital, reflecting the equity risks; the second should be more akin to a regulatory asset base (RAB) in the utilities and closer to the cost of debt; and the third should be a charge to operating costs. The customers should benefit from the refinancing when the project comes into operation.

9. The current RIIO (Revenue = Incentives + Innovation + Outputs) periodic review price caps for the transmission and distribution companies are already being significantly outperformed – in part because of mistakes in the assumptions – and have resulted in higher prices than need to be charged for the efficient delivery of their functions. Ofgem should consider what actions should be taken now.

10. For the networks, going forward, there should be no more periodic reviews in the current RIIO framework. Technical change is so fast that predicting costs eight–ten years hence is impractical.

11. The government should establish an independent national system operator (NSO) and regional system operators (RSOs) in the public sector, with relevant duties to supply, and take on some of the obligations in the relevant licences from the regulated transmission and distribution companies. The NSO and the RSOs should, where practical, open up the various functions and enhancements to the networks to competitive auctions and, at the local level, invite bids for network enhancements, generation and storage, and demand-side response (DSR) from energy service companies.

12. The separate generation, supply and distribution licences, at least at the local level, should be replaced by a simpler, single licence.

13. As a result of the above changes, the role of Ofgem in network regulation should be significantly diminished.

14. There should be a default tariff to replace the Standard Variable Tariff (SVT), based on the index of wholesale costs, the fixed cost pass-throughs, levies and taxes, and a published supply margin.

15. Capping the margin would be the best way to meet the objectives of the new draft legislation. By focusing on the margin within the default tariff structure, competition would be enhanced, thereby encouraging new entrants.

16. The government should issue an annual statement to Parliament, setting out the required capacity margins and providing guidance to the NSO and RSOs.

Executive Summary

1. This review has two main findings. The first is that the cost of energy is significantly higher than it needs to be to meet the government's objectives and, in particular, to be consistent with the Climate Change Act (CCA) and to ensure security of supply. The second is that energy policy, regulation and market design are not fit for the purposes of the emerging low-carbon energy market, as it undergoes profound technical change.

2. Since late-2014, the prices of oil, gas and coal have fallen significantly, contrary to the modelling and forecasting of both the Department of Energy & Climate Change (DECC) and the Committee on Climate Change (CCC). Since then, the price of renewables has been coming down fast too, as have the costs of addressing intermittency, as a host of new battery and other storage and demand-side options become available. Productivity increases should have been putting further downward pressure on the costs of transmission, distribution and supply. New technologies should mean lower, not higher, costs and much greater scope for energy efficiency. Margins should be falling as competition should be increasing. Yet in this period, households and industry have seen limited benefits from these cost reductions. Prices have gone up, not down, for many customers.

3. These excessive costs are not only an unnecessary burden on households and businesses, they also risk undermining the broader democratic support for decarbonisation. In electricity, the costs of decarbonisation are already estimated by the CCC to be around 20% of typical electricity bills. These legacy costs will amount to well over £100 billion by 2030. Much more decarbonisation could have been achieved for less; costs should be lower, and they should be falling further.

4. Many of these excessive costs are locked in for a decade or more, given the contractual and other legal commitments governments have made. These include Renewables Obligation Certificates (ROCs), feed-in tariffs (FiTs), and low-carbon contracts for difference (CfDs) granted to early-stage wind and solar, larger-scale nuclear, biomass, and offshore wind. Since the ROCs, FiTs and low-carbon CfDs are formal contracts, they are taken as *given* in this review. The task is to find ways of minimising the burden these impose, and making them transparent, ring-fenced, and separated out from the market, where costs should be coming down.

5. The burden on households and businesses would have been even greater had there not been a financial crisis in 2007/08 which held down demand, and a parallel continued decline of the energy-intensive industries. Had the crash not happened, GDP would be perhaps 20–25% higher in 2017

(assuming no sharp fall in GDP in the immediate aftermath of the crash and 2–3% GDP growth since then). There would then have been a serious capacity crunch and much higher prices. As it is, the UK has flirted with dangerously low capacity margins despite the GDP effect, and this drives up prices as the more expensive marginal plant is drawn onto the system to match demand.

6. In the current decade, the government has moved from mainly market-determined investments to a new context in which almost all new electricity investments are determined by the state through direct and often technology-specific contracts. Government has got into the business of ‘picking winners’. Unfortunately, losers are good at picking governments, and inevitably – as in most such picking-winners strategies – the results end up being vulnerable to lobbying, to the general detriment of household and industrial customers.

7. As a consequence of Electricity Market Reform (EMR), the government now determines the level and mix of generation to a degree not witnessed since these were determined by the nationalised industries – notably the Central Electricity Generating Board (CEGB). Investment decision-making has been effectively quasi-renationalised. This is a direct consequence of EMR. The government, not the customer, has become the client.

8. In determining not just the level of new capacity, but also the composition of the low-carbon portfolio, the government started out with some of the most expensive technologies first, and it could be argued that since then it has at times been exploring even more expensive options. The result is that British households and businesses are locked into higher renewables and other low-carbon generation costs than they need be to achieve the decarbonisation objectives for decades to come.

9. These state-backed contracts have been supported by the return to formal modelling and forecasting by DECC (now BEIS, the Department for Business, Energy & Industrial Strategy) and the CCC. In the case of DECC, the results have at times been spectacularly bad. In particular, in the first half of this decade, DECC focused on its forecasts of high, rising and volatile gas prices, and therefore it could conclude that the wholesale price of electricity would rise to over £92/MWh by the early 2020s. It was confident that because fossil fuel prices (and particularly gas) were going up, households would be relatively better off as a result of its policies by around 7% by 2020.

10. The EU Renewables Directive and its particular definition of renewables has been a major contributor to raising the costs above those necessary to reduce carbon emissions to meet the CCA. A further

contributor is the inefficient way in which the carbon budgets have been addressed, notably by not moving against coal earlier.

11. The overwhelming focus on electricity rather than agriculture, buildings and transport has added to the cost. Agriculture in particular contributes 10% greenhouse gas (GHG) emissions, and the costs of reducing these emissions are much lower than many of the chosen options because the economic consequences of a loss of output in agriculture are small. Agriculture comprises just 0.7% GDP and at least half its output is uneconomic in the absence of subsidies. With the development of electric vehicles (EVs) it is apparent that transport can contribute more. The CCC could have paid more attention to the lower marginal cost of abatement in these sectors.

12. Keeping costs down is all the more important as the electricity system faces a series of major challenges over the next decade. Not only does it need to meet the carbon budgets, it needs to do this in the context of major retirement of existing capacity, the investment requirements to handle the intermittent renewables, the coming of electric transport, and the wider demands of a digitalising economy. These challenges are on a scale and magnitude not witnessed since the reconstruction of the electricity industry immediately after the Second World War.

13. The energy sector is going through a technological transformation as electricity becomes an increasingly dominant form of energy. Previous structural breaks have come from single technologies, like the coal-fired power station, the gas turbine, and the civil nuclear power stations. This time there are structural breaks which span the whole economy as it digitalises, the transport sector as it electrifies, and the generation, transmission, distribution, supply and the demand for electricity. We are moving towards a decarbonised, digital, smart electric energy world, offering the prospect of ever-lower costs from cleaner energy.

14. The CCC neglects some of the opportunities of these technology impacts in its time horizon to 2050, arguing that any new technologies will have to be deployed before 2030 if they are to make much impact before 2050. This, together with the assumption that gas prices will rise by 30% by 2030, is a key rationale for the roughly linear profile of emissions reductions from now through to 2030. If the objective is limited to the CCA 2050 target, then the carbon budgets overegg the early stages, and make the trajectory between now and 2050 more expensive than it needs to be. Indeed, with such early action in the linear trajectory, it may turn out that decarbonisation is achieved much faster.

15. Tempting though it is to many observers to predict how this transformation is going to take place, and profitable to many lobbyists to persuade government that their specific technologies and projects are the right answers, the design of energy policy and the interventions to achieve the objectives should be driven by the uncertainty about the detailed shape of the decarbonisation path. In order to achieve the prize, it is important not to try to pick winners, and to focus on the framework within which the private sector brings new ideas, new technologies and new products to the end-user. Avoiding detailed intervention is a key to keeping down the cost of energy.

16. Since 2015, a number of reforms have begun to reverse some of the more grossly inefficient dimensions of current policies. The greater use of auctions has begun to bear down on excessive costs, but there is a long way to go. The decision to exit coal by 2025 is a belated but welcome step to recognise that switching away from coal is the cheapest way to decarbonise. It should have been the first option.

17. Notwithstanding the significant cost reductions from the auctions so far, existing energy policy is not fit for these new purposes. It remains complex and expensive, and it is slowing down the transition to a decarbonised economy.

18. The measures necessary to reduce the costs include: the unification of the capacity and FiTs and CfDs auctions on the basis of equivalent firm power (EFP); the gradual reforms of the structure of FiTs and CfDs in the transition to their eventual abolition; and further enhancements to competition in the wholesale and balancing markets. There should be significant reforms of the regulation of transmission and distribution focused on the role of system operators at the national and local levels, and the replacement of the specific licences for distribution, supply and decentralised generation with a general licence. A default supply tariff should be required and the margins published. Finally, carbon prices and energy taxes should be harmonised.

19. This package of measures is a major shift from the original market design and regulation model at privatisation, and moves on from EMR. It would create a simpler, more competitive structure fit for the new purposes. Instead of low-carbon technologies being grafted onto the fossil fuel-based system, the new world is radically different, backed up by new smart technologies, data and smart energy networks and services. A common carbon price would significantly lower the cost of decarbonisation and greatly enhance incentives.

20. As the fixed system costs gain an increased share of total costs, it will be government that ultimately decides the allocation between customer classes of these fixed costs. The legacy costs are also fixed. The scope for protecting the poorest customers will be increased, and the government should consider a universal basic allocation of fixed costs.

21. The fixed costs also permit a more efficient allocation to the industrial sector, and particularly to those companies facing international competition. In addition to exemptions from the legacy costs, consideration should be given to the relative burdens on industry and households from the rising proportion of fixed costs. However, neither should be exempt from the carbon price.

22. These measures require significant institutional reform. The system operator model should be further developed, with an independent national system operator (NSO) and a series of regional system operators (RSOs) playing a bigger part.

23. Ofgem's role in regulation should be significantly reduced as the NSO and RSOs assume some of the duties currently placed on distribution network operators (DNOs) and Ofgem, with much greater use being made of competitive tenders and auctions. The licensing regime at the local level should be simplified, abolishing the increasingly anachronistic distinctions between generation, supply and distribution, which are being overtaken by the new technologies that are emerging.

24. The comprehensive long-term framework set out in this review is a practical and evolutionary package, and will deliver benefits not only over the coming decades, but in the immediate future too. Immediate benefits would come from revisiting the transmission and distribution price reviews, introducing a default tariff for supply focused on the margins, and reforms to the FiTs to capture the refinancing gains after existing commitments have been fully met.

25. This long-term framework, coupled with these immediate measures, is the least-cost way of achieving the objectives, with the prospect that the 2050 carbon target could be met at lower cost, and could even be met early, to the benefit of households and industry.

26. Not to implement these recommendations is likely to perpetuate the crisis mentality of the industry, and these crises are likely to get worse, challenging the security of supply, undermining the transition to electric transport, and weakening the delivery of the carbon budgets. It will continue the unnecessary high costs of the British energy system, and as a result perpetuate fuel poverty, weaken industrial competitiveness, and undermine public support for decarbonisation. We can, and should,

do much better, and open up a period of falling prices as households and industry benefit from the great technological opportunities over the coming decades.

1. Introduction

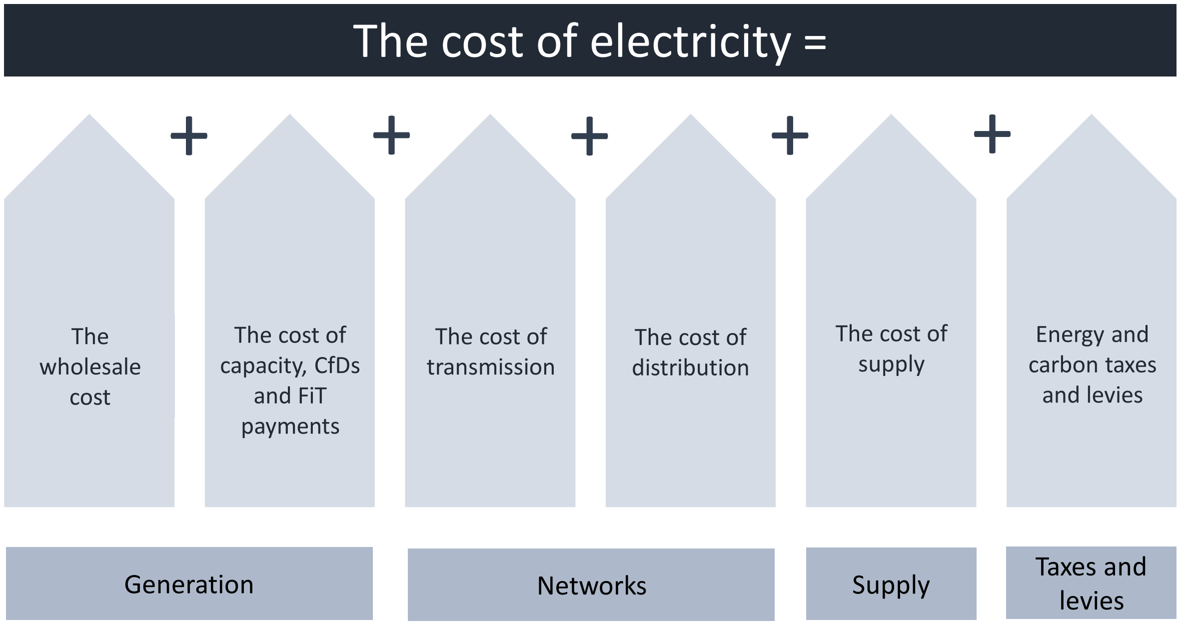
1. The cost of energy is not something the government can directly fix. It is the outcome of a myriad of decisions by companies and organisations around the world. Governments cannot fix the price of coal, gas or oil, the technologies, the price of cables, of IT, of labour, or of data. Nor can government predict the price of energy – and when it tries, unsurprisingly, it often does it very badly.

2. The price of energy is the *outcome* of the auctions and competitive activities, of the decisions of numerous businesses and households and industrial users, and of the exercise of market power. What government can and should do is set the framework within which the cost of energy is efficiently determined by the interaction of all these forces – and in particular the objectives, market design, regulatory frameworks, subsidies and the taxes – and it should bear down on the market power.

3. **Part I sets out the key objectives (decarbonisation and security of supply) and the constraints (the bills to households and industry); the complexities of current policies, levies, subsidies and regulations; the legacy costs; and the scale of technological change and the opportunities this presents.**

4. The government's current roles go much further to include defining carbon and security of supply objectives; setting levies; granting subsidies; designing and letting contracts; and taxing, procuring and regulating networks. Whether it needs to undertake all these functions, and how cost-effectively it does this, will have a significant impact on the cost and price of energy.

5. The components of the cost of electricity are easy to state, but harder to explain. They are as follows.



Note: CfD, contract for difference; FiT, feed-in tariff.

6. In each segment of this value chain there is a mix of fundamental underlying economic costs, the costs of policy, interventions, levies and regulation, and the exercise of market power.

7. The lowest costs that can be achieved are those that meet the overarching policy objectives, without the exercise of market power. This is the exam question for the electricity sector: does it meet the objectives at least cost?

8. Like the costs, these objectives are easy to state but hard to define. At the high level there are just two: the 2050 *climate change target* in the Climate Change Act (2008) (CCA), and the provision of adequate *security of supply*. While the carbon target is well defined, security of supply is more complex, including the level of capacity margin, the composition of that capacity, the flexibility options, and the extent to which resilience should be built into the electricity system.

9. There are a host of other targets added on, frequently without considering the full consequences for these high-level objectives. These include: air quality, industrial emissions, transport emissions regulations for vehicles, building regulations and agricultural subsidies and their impacts. The EU adds to all these targets specific ones for its particular definition of renewables and for energy efficiency. This complexity comes at a significant price. Section 2 considers both the high-level objectives and the plethora of ancillary targets and policy objectives, and their consequences for the cost of energy.

10. It is not particularly difficult to set out what an efficient energy system might look like which meets the twin objectives of the climate change targets and security of supply. There would, however, remain a binding constraint: the willingness and ability to pay for it. There have to be sufficient resources available, and there has in a democracy to be a majority who are both willing to pay and willing to force the population as a whole to pay. This constraint featured prominently in the last three general elections, and it has not gone away. Indeed, without the reforms proposed in this review, it may tighten. As well as looking at the problems of resource allocation from the perspective of the twin objectives, it is also necessary to look at this constraint. In willing the ends (the objectives), the government must also will the means, and be able to convince the electorate that they should pay for them. Section 3 looks at household incomes, fuel poverty and energy costs, industrial energy costs, and ability to pay – and whether the objective of having the lowest bills in Europe is properly defined.

11. The cost of energy is profoundly influenced by the detail of energy policy. There are multiple energy policy interventions across the full supply chain. These include taxes on inputs and outputs, VAT, and the tax treatment of investments and R&D. The planning system influences the type and timing of investments. Capacity auctions and feed-in tariffs (FiTs) and contracts for difference (CfDs) are determined by government. The government provides guarantees. The networks are regulated, and supply prices are subject to some explicit and lots of implicit controls. There is no 'free market' in electricity; nor will the industry ever approximate a free competitive market. Rather the challenge is to maximise competition *within* a policy framework. The cost of energy is determined by the interaction between markets *and* the state, and the challenge for energy policy is to get this mix right.

12. A mass of interventions, and especially technology-specific contracts, in turn attracts vested interests. The implication of the state determining almost all investments is that the state – and not the consumer – is now the major client. Energy policy has been partly captured, with the result that our decarbonisation is slower and more costly than it need be; our security of supply is weaker than it should be; and households and industry pay too much for their energy. Section 4 considers the main current policy interventions and how they do (and do not) fit together, along with a look at the forecasting record that informs them. It considers the problem of capture and how the redesign of energy policy can mitigate these rent-seeking activities, which have driven up the cost of energy.

13. No energy system is optimal. Assets with long lives have been developed according to the assumptions made at the time. We start with what we have, not what we would like to have. This includes the coal assets and the existing nuclear fleet, and the first-generation renewables. Section 5 sets out the current asset legacy, the likely retirements, and the legacy costs which have arisen from the EU Renewables Directive and other government contracts. It proposes a way of taking some of these costs out of the market in order to minimise the distortions to the emerging new energy markets.

14. The cost of energy depends on the specific historical circumstances and, in particular, the technological conditions and the costs that they dictate. The optimal structure of the industry should broadly reflect these costs, as should regulation. When these change fundamentally, so too should the industry and the regulatory structures. There can be little doubt that the energy market is going through a period of profound technical change, on a scale not seen since at least the late-19th century. Indeed, it needs to if there is to be a successful decarbonisation. The economy that the energy sector serves is digitalising, bringing profound changes through robotics, 3D printing and artificial intelligence (AI). This emerging digital economy is overwhelmingly an electric one and driven by data. It is a world of increasing relative demand for electricity, and of increasing demand for security of supply. In an interconnected digital economy, interruptions of supply may be more costly, but there is a plethora of new ways in which the market, if allowed to do its work, can mitigate these.

15. Technological change within the energy sector is profound. Fracking and shale oil and shale gas have already changed global energy markets. Within electricity, the traditional characteristics of passive demand and little storage have shaped the vertically integrated companies that have served us for the last century. This is changing: batteries, storage and smart systems are transforming both demand and supply, driving down the cost of intermittency and increasing energy efficiency through smart energy services. The whole-system costs are being transformed. The corporate structures and policies designed for the 20th-century world no longer work well.

16. Generation is changing too. There have been radical breakthroughs in new materials. Among the main low-carbon technologies – solar (including wind), nuclear, geothermal and gravity (mainly hydro) – there are exciting new opportunities, especially in next-generation solar, and potentially over a longer time span for nuclear too. The speed and success with which these are developed is core to industrial strategy.

17. In this digital and new-generation technologies world, transport is electrifying. The government has set a new target that no new petrol or diesel cars (excluding hybrids) will be sold after 2040. This is a new constraint, with profound implications for the electricity industry and its costs. The electricity industry is becoming part of the transport sector and vice versa. Section 6 considers the transforming technology context and how it should shape the longer-term architecture of energy markets and policies.

18. **With the building blocks in place, Part II turns to the key components of the energy supply chain.** Sections 7, 8, 9 and 10 look at generation costs, capacity and FiTs costs; transmission and distribution costs; supply margins; and energy taxes and levies, respectively, and set out practical measures to reduce many of these, both now and over the longer term.

19. **Part III sets out a long-term framework, and a road map with the immediate actions to facilitate this transformation.**

20. Energy policy needs to provide a framework, rather than intervening in the actual decisions and making direct investment decisions. It should in particular avoid choosing specific technologies wherever possible. This is especially important in a time of rapid technological change, changing cost structures, and given the uncertainty that characterises these changes. Where technologically specific decisions are unavoidable, for example in nuclear, it is imperative to use bidding processes and competitive auctions as far as possible. Section 11 brings the reforms proposed for each part of the electricity supply chain in Part II into a coherent overarching longer-term framework, including reforms of the energy policy and regulatory institutions. It sets out a new framework, with a national system operator (NSO), and new regional system operators (RSOs) at its core, built for and upon the new challenges and opportunities which digital, active demand, storage and zero marginal cost technologies bring.

21. To get from here to there, major new investment will be required – to replace the retiring coal-fired power stations and the ageing nuclear fleet, bring in new customers (notably for transport), develop new energy products and services, and innovate through the entire supply chain. In any normal market, investment is an opportunity to earn profits in the future. Prices do not have to go up to finance this. That is what balance sheets, equity and debt are for.

22. This review sets out a road map of immediate actions to get from the current unsatisfactory state of affairs towards the decarbonised world, and to facilitate the investment opportunities in a way that maintains and enhances security of supply, at the lowest cost. There is no reason why this

cannot be a world of gradually falling energy costs for both households and industry, though there will be decisions to be made in terms of allocating the burden. Section 12 recommends the immediate actions to ensure that the *price* of energy better reflects the *costs* of energy.

23. Some will argue that more change is bad, and that it increases uncertainty. This is often a poor disguise for vested interests, especially when it comes to addressing market power. To maintain the status quo is to condemn the UK to relatively expensive energy; undermine the decarbonisation transition; allow the security of supply position to remain at best precarious; and erode public trust and therefore democratic support for cleaner energy. This resistance to change is not without significant costs to households and companies: continue with business-as-usual and prices will most likely go on rising until there is a crisis big enough to bring the structures tumbling down. It is a price we do not need to pay. The status quo is not going to be a good place to be in the medium and longer term. It is not sustainable, and therefore it will not be sustained. The conclusions are presented in section 13.

PART I

THE BUILDING BLOCKS

2. The Objectives

This section addresses:
- **the key objectives**
- **reducing the costs of meeting the 2050 target**
- **spreading the carbon reduction burden across other sectors**
- **sorting out the role of government in security of supply**
- **addressing other overlapping objectives**

1. The lowest cost of energy is an outcome of an efficient energy sector, and an efficient energy sector is one that best meets the overarching objectives.

2. There is no shortage of objectives. There is nothing new in this, and nothing wrong with multiple objectives, provided there are at least as many policy instruments as there are objectives, and provided the trade-offs are defined.

3. With the coming of the climate change imperative to decarbonise the economy, the objectives have shifted from primarily focusing on security of supply to including decarbonisation. The two have to be achieved simultaneously. This is the high-level energy dilemma, but solving this dilemma is perfectly achievable. One objective is about the amount of carbon, and hence the price and costs of carbon; the other is about the capacity margin, and hence the investment in sufficient capacity to meet demand.

4. There has always been in the background an additional concern about costs and prices. Adding considerations of the level of costs to the security and decarbonisation objectives is what creates the *trilemma* on which government has focused.

5. An absolute objective of reducing costs is not necessarily compatible with the other objectives. It has to be 'subject to meeting the security and decarbonisation objectives', because security and decarbonisation have costs. Reducing the cost of energy cannot be an absolute objective. It is a *relative* one: it is about achieving the other two objectives efficiently.

6. Customers do have to be able to pay. The ability to pay, and the willingness to vote to be forced to pay are binding constraints (not objectives). Businesses can opt out by relocating overseas or reducing production, so this is also a constraint. Section 3 explores these constraints in greater detail.

7. Some argue that there are trade-offs with the other objectives: that we could have lower bills if we decarbonised more slowly, or even abandoned the decarbonisation objectives and associated policies. While this is broadly true at least in the short term, it is also true that Parliament legislated to decarbonise and passed the CCA by an overwhelming majority. It has also approved the Fifth Carbon Budget. In this review, and in line with the Terms of Reference, these are taken as a *given*. The issue is not *whether* to water down the climate change targets, but rather to consider *how* they can be achieved at lowest cost.

8. On security of supply, there is no parallel 'Security of Supply Act', although the objective is embedded in energy legislation. All political parties understand that security of supply is a clear necessity in a modern economy. The question is not *whether* security of supply should be traded off against costs, but rather *how* it can be achieved at lowest cost. Therefore, this review similarly takes the overall security of supply objective as *given*.

9. The conclusion that follows is that we face a two-part energy challenge – how to meet security of supply and climate change objectives simultaneously; *and* how to do this at the lowest cost possible. Costs are not an objective like the other two: they are an outcome, and the ability to pay is a binding constraint. So, strictly speaking, there is no trilemma of energy objectives.

10. It is a core part of energy policy to provide clarity on objectives.

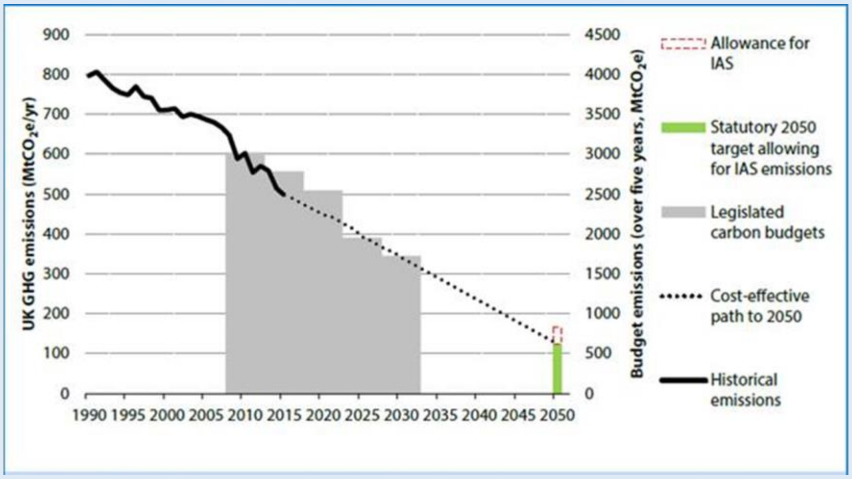
Objective (i): Decarbonisation, climate change and the Climate Change Act

11. The UK has a binding *unilateral* carbon *production* target set out in the CCA – to reduce greenhouse gas (GHG) emissions in the UK by at least 80% by 2050, compared with 1990 levels. Although the UK is a signatory to the Paris Agreement, and is bound until at least March 2019 by the relevant EU directives, none of these (except the Renewables Directive) is strictly binding.

12. The 2050 carbon target is embedded in carbon budgets set out on a five-year rolling basis. The UK has set five carbon budgets covering successive five-year periods up to 2032. The path to 2050 and the five carbon budgets are set out in the charts below. Brexit will make no difference to the carbon targets: the UK's climate targets are already unilateral.

COMMITTEE ON CLIMATE CHANGE CARBON BUDGETS

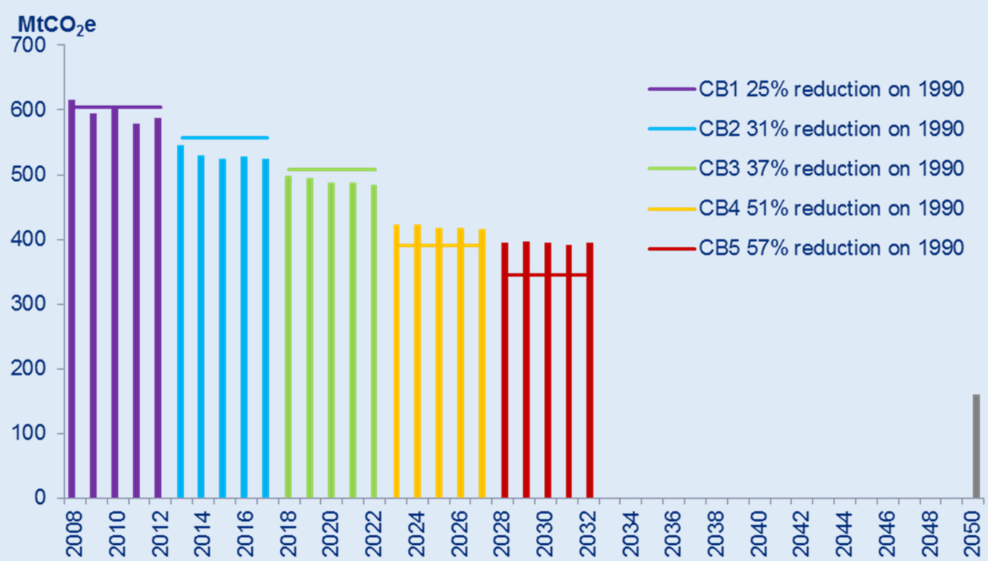
FIGURE 1: UK CARBON BUDGETS AND THE COST-EFFECTIVE PATH TO THE 2050 TARGET



Source: Figure 1.1 from Committee on Climate Change (2016), 'UK Climate Action Following the Paris Agreement', p. 17. Available at https://www.theccc.org.uk/wp-content/uploads/2016/10/UK-climate-action-following-the-Paris-Agreement-Committee-on-Climate-Change-October-2016.pdf.

Notes: Historical emissions are on a 'gross' basis (ie, actual emissions). Carbon budgets are on the current budget accounting basis, excluding international aviation and shipping (IAS), but allowing for IAS in the 2050 target.

FIGURE 2: ACTUAL AND FORECAST EMISSIONS AND PERFORMANCE AGAINST CARBON BUDGETS

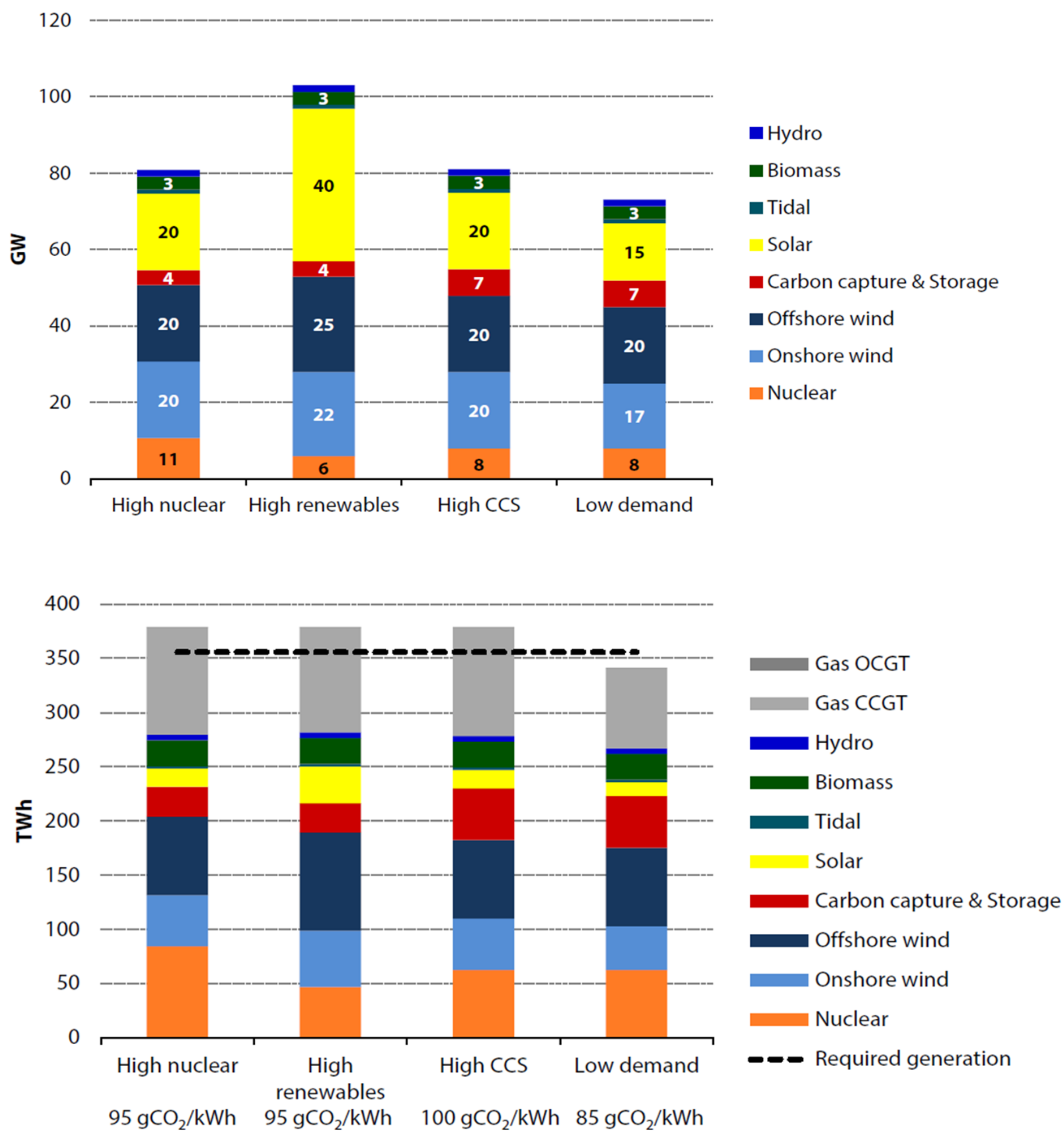


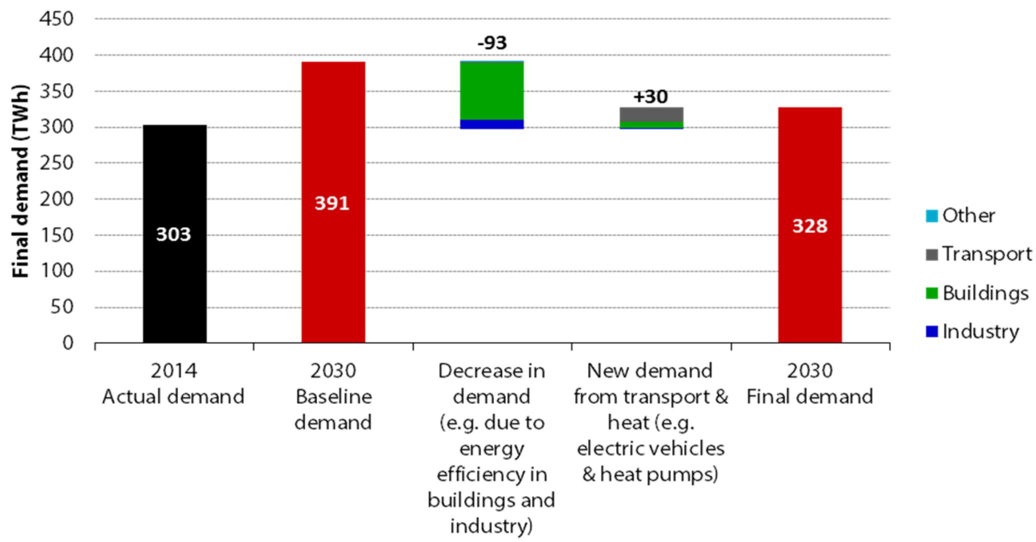
Source: BEIS (2017), Energy and emissions projections.

Notes: Horizontal lines represent the levels of legislated carbon budgets. Vertical bars are actuals/projections of the UK Net Carbon Account based on policies that exist or that are at an advanced stage of planning. The vertical bar in 2050 indicates that emissions need to be at least 80% lower than in 1990, equivalent to around 160 $MtCO_2e$. This is on the basis of the current net carbon account scope.

13. The Committee on Climate Change (CCC) provides detailed electricity sector scenarios for the Fifth Carbon Budget. These are set out below for capacity and generation, and the assumptions about demand.

FIGURE 3: ELECTRICITY SECTOR SCENARIOS FOR THE FIFTH CARBON BUDGET





Source: Committee on Climate Change (2015), Advice on the Fifth Carbon Budget.

Notes: OCGT, open-cycle gas turbine; CCGT, closed-cycle gas turbine.

14. These scenarios illustrate the opportunities, but also the scale of uncertainty. They illustrate the importance of energy efficiency in holding down demand, and also the role of carbon capture and storage (CCS) options, and what happens if these do not materialise. The world will turn out differently, and the great risk with these scenarios is that government is encouraged to pick one of them, and the 'winners' that this intervention would create. The risks of relying on this sort of planning are highlighted in section 4.

15. The Committee on Climate Change (CCC) has considerable flexibility in how it defines carbon budgets. The CCA does not require any particular linear trajectory to meet the 2050 target as set out in the chart above. We could act much faster now, and then cruise or go beyond the target in the 2030s and 2040s. Or we could slow down now and accelerate later.

16. The CCC chose its preferred path partly on the basis of two assumptions. The first is that gas prices will rise, and here the CCC uses the Department for Business, Energy & Industrial Strategy (BEIS) range of scenarios for gas prices to 2030, all of which imply rises from the current levels. The central assumption is a 30% rise in gas prices by 2030. The second is that new low-carbon technologies with potential for a significant impact by 2050 are likely to require some deployment prior to 2030. Looking at the scenarios above, this is seen in terms of CCS. Given the uncertainties about CCS and in particular meeting the deployment requirement by 2030, one way of interpreting this is that we are stuck with nuclear, wind, current solar and biomass. The good news for the cost of energy is

that both of these are doubtful assumptions, and hence the cost of achieving the 2050 target may be lower, and we may even reach it early. There is no obvious reason why gas prices should go up, and in any event the sheer scale and speed of technological progress may transform our options after 2030. The coming technological opportunities are discussed in section 6.

17. Different trajectories would obviously have different costs. It is important to note that we cannot have certainty about what the costs of the alternative paths might be, since we do not know all the future technologies, and we do not know how the efficiencies of the supply chain will change. The path to 2050 will be littered with 'surprises'. But it is most likely that as technology moves on, the costs of meeting the overall target will fall, and perhaps very significantly. In other words, it will be cheaper to reduce carbon tomorrow than today. Indeed it has to be.

18. We do know the current costs of the alternative low-carbon options now, but even in this case it turns out that the costs are not quite what they seem. All generation technologies impose costs on the electricity system, of which the Renewables Obligation Certificates (ROCs), FiTs and low-carbon CfDs are only a part. Genuine subsidy-free renewables should be defined *after* the explicit or implicit carbon price necessary to reach the CCA target and the carbon budgets, and *after* also taking into account system capacity and network costs.

19. The carbon budgets are already defined until 2032. Parliament has approved them all, and 15 years is a long time in the electricity sector in terms of predictability. Beyond 2032, any detailed forecasts of costs are likely to turn out wrong, and perhaps by orders of magnitude. This is a key lesson from the attempts at forecasting so far, as discussed in section 4.

THE CLIMATE CHANGE ACT SETS OUT HOW GOVERNMENT MUST SET AND MANAGE CARBON BUDGETS

- There is a legal duty to ensure that the UK carbon account does not exceed the carbon budget for a given budgetary period.
- Once a new carbon budget is set, the government is required to present to Parliament its proposals and policies for meeting carbon budgets up to and including that period 'as soon as is reasonably practicable'.
- There is a general duty for the Secretary of State for BEIS to prepare proposals and policies that will enable carbon budgets to be met; it is therefore implicit that where there is a policy gap BEIS is required to develop policies or proposals to address this gap.
- The government can plan to meet a carbon budget using flexibilities (eg, carrying forward over-achievement from one budget to another or using international credits) as long as this is consistent with keeping on track to meet the target for 2050, and bearing in mind the duty to have regard to the need for UK domestic action on climate change.
- The government has to report on progress each year to Parliament, and to submit a final statement of the UK's carbon account for each budgetary period. If the final statement shows that the carbon budget for a budgetary period has not been met, the statement must explain why it has not been met and, as soon as is reasonably practical, the Secretary of State must lay before Parliament a report setting out proposals and policies to compensate in future periods for the excess emissions.
- There are no financial penalties for missing a carbon budget. Government decisions which are likely to lead to missing a budget could be subject to judicial review.

Source: BEIS.

20. There are provisions under the CCA to change a budget level once it has been set. The bar for change is set high and the process is lengthy. In particular, the following hurdles are in place.

HURDLES TO REVISING CARBON BUDGETS

- The need to demonstrate that there has been a 'significant change' in circumstances since the budget was set and take into account nine 'matters' set out in the CCA (ranging from economic circumstances to international/EU developments).
- The CCC must provide advice. Ministers must take this into account but they do not have to agree.
- The devolved administrations must be able to consider the advice (a minimum three-month period). UK ministers must take into account representations of the devolved administrations before coming to a decision.

Once these processes have been completed, the carbon budgets can be changed only through secondary legislation. This is subject to the affirmative procedure – so government needs to win votes on the floor of both Houses of Parliament.

Source: BEIS.

21. The government has already reviewed the Fourth Carbon Budget (covering the period 2023–27). This concluded in 2014 with the decision not to amend the budget level.

22. In addition to changing the actual budget level, the CCA gives the CCC a number of 'flexibilities' on when and how to reduce UK emissions en route to 2050 (similar to changing budget levels, the government still needs to seek advice from the CCC and consult the devolved administrations before employing them). These flexibilities are as follows.

FLEXIBILITIES ON THE PATH TO 2050

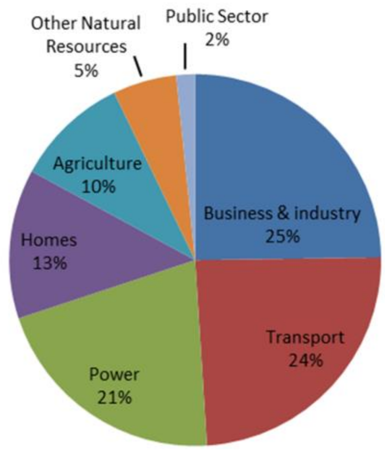
- *The UK can carry forward over-achievement from earlier carbon budgets.* The CCA allows for government to roll forward over-achievement from one carbon budget to the next, so that early action to reduce emissions can count towards the following budget.
- *The UK can 'borrow' from later carbon budgets.* The CCA allows for the government to increase the carbon budget in one period with a corresponding tightening in the next carbon budget. This 'borrowing' is limited to 1% of the later carbon budget.
- *The UK can buy international carbon credits.* A limit on the use of credits must be set, with Parliamentary approval, 18 months in advance of the relevant carbon budget period starting.

Source: BEIS.

23. In using any of these 'flexibilities', the government must always have regard to the need for UK domestic action on climate change (ie, implying that domestic action should take priority).

24. The CCA target is one for the UK as a whole, and not for any specific sector. The sectoral emissions are set out below.

FIGURE 4: UK GHG EMISSIONS BY SECTOR IN 2015



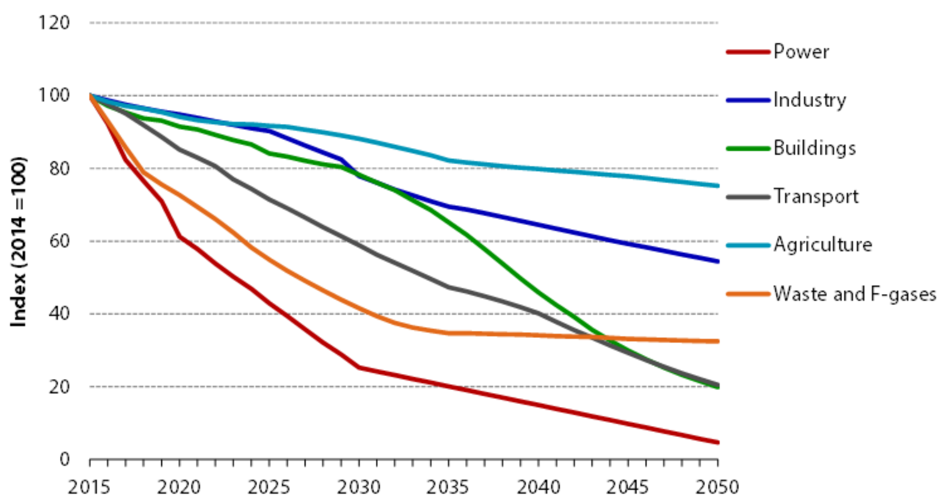
	$MtCO_2e$	%
Business & industry	123	25
Transport	120	24
Power	104	21
Homes	64	13
Agriculture	49	10
Other natural resources	27	5
Public sector	8	2

Source: BEIS (2017), Final UK greenhouse gas emissions national statistics, 1990–2015, https://www.gov.uk/government/statistics/final-uk-greenhouse-gas-emissions-national-statistics-1990-2015.

Note: 'Other natural resources' covers land use, forestry, waste and fluorinated gases.

25. The CCC has set out the 2050 scenario for each of the main sectors of the economy as presented in Figure 4. These start with a baseline, take the government's business-as-usual projections, add in existing policies, take account of the rising carbon price assumption, and ensure that it all adds up to meet the 2050 target.

FIGURE 5: CENTRAL SCENARIO EMISSIONS PATHS TO 2050



Source: CCC analysis.

26. If the overall objective is to meet the target at lowest cost, there is no *a priori* reason for the degree of concentration on electricity. In particular, agriculture contributes 10% of total emissions. This is only for the emissions that are actually measured, however. This sector has an annual output value of around £9 billion, and is subsidised in a variety of ways, including the Common Agricultural Policy (CAP) to the tune of roughly £3 billion, tax benefits, and exemptions from payments for the sector's multiple associated pollution. In total, the level of agricultural support is possibly of the order of half the value of its output, or more. Put another way, the economic costs of bearing down on agricultural carbon emissions are very low compared with those of the other sectors, and it has considerable sequestration options too. At the margin, this would probably be a lowest-cost sector for reducing the overall costs of meeting the carbon budgets.

27. There would also be significant additional benefits from both reducing emissions and increasing sequestration in agriculture, thereby enhancing natural capital, which underpins the government's 25 Year Environment Plan.

28. Transport is the largest source of emissions (24%), and its decarbonisation will be significant for electricity, as discussed in section 6. The electrification of transport is happening faster than the CCC and others expected, which could accelerate its potential to contribute more to the carbon budgets.

29. The decarbonisation of electricity will still be required, and indeed is essential since so much of the economy is likely to be electric by 2050. But the contribution of other sectors does impact on the trajectory for the electricity sector in the carbon budgets to 2050. The failure to exploit cheaper options now has increased the total costs of achieving the 2050 target.

30. In section 10 I recommend the harmonisation of carbon prices across the economy to reduce the overall costs, and in particular the extension of carbon pricing to agriculture, and a longer-term general transitioning from fuel duty to a more explicit carbon component in transport taxation. A common carbon price across the whole economy (and not just electricity) helps to minimise the costs of the overall CCA target between the sectors. This, rather than the sectoral planning implicit in the CCC sector scenarios, is the first-best route to minimising the costs of the decarbonisation transition.

31. The CCA raises serious issues about the allocation of costs between different types of customer. It is a unilateral carbon production target, and therefore can be met by reducing the emissions of current activities, or by switching home production for imports. Most other countries with which the UK trades are not subject to such a unilateral target of this form or ambition.

32. As a result, to avoid the perverse impacts on UK industry through a unilateral policy-induced reduction in competitiveness in export sectors, the efficient outcome involves compensating the traded sectors or using a common border carbon price. A second-best unilateral target requires a second-best intervention to address the impacts on international competitiveness. Some considerable adjustments already occur. On the other hand, some costs are borne by industry and not households – eg, the Carbon Price Floor (CPF) and the Climate Change Levy (CCL). In both cases these have been developed in an *ad hoc* way, and the result is an inefficient allocation of costs in respect of industry. I return to these issues and their possible remedies in sections 3 and 10.

Objective (ii): Energy security

33. In the energy sector, security of supply has been an objective for most of the history of the industry – and one that has gained in significance as the economy's reliance on electricity has grown. Its relevance may increase further with digitalisation and as the economy decarbonises.

34. Security will not be met purely by private sector incentives and private markets because of uncertainty about both demand and the availability of supplies (including the physical reliability), the lack of storage and passive demand. The uncertainty creates risks to the system rather than to individual generators; the lack of storage means that demand must be instantaneously met; and passive demand means that there cannot be instantaneous demand-side responses (DSRs). All of these are system characteristics.

35. An excess capacity margin for firm power depresses the wholesale price of electricity to a level below that necessary to recover the full costs of power station investments. No rational capitalist will deliberately encourage excess supply, except as a strategic means of entry deterrence. This is over and above the depressing effect on wholesale prices caused by non-firm zero marginal cost renewables.

36. The nature of the security of supply problem evolves with changes in technology. For the last century, security of supply has been a simple equation of demand forecasts, met by enough coal and nuclear power stations to provide a comfortable security of supply margin. As the economy digitalises, and as the share of electricity grows, security may be of greater economic significance. In some cases, this will lead consumers, both industry and households, to install their own storage for back-up. Batteries may contribute to these measures. They are both a route to ensuring security of supply in firm power and an opportunity to use the flexibility of non-firm demands, especially for EV charging. It may be that eventually decentralised energy systems internalise these problems without greater need for additional large-scale power stations. Digitalisation may make security more important, and at the same time cheaper to provide.

37. The economics of system requirements and individual incentives are not automatically reconciled without intervention. In particular, there is a risk that people opt out, leaving the burden of system costs to others. These opt-out incentives are reinforced by taxes and levies applied to system users.

38. The coming of new and enhanced storage technologies and the development of smart technologies for managing energy demand will change the resilience of the system and the required capacity

margins. These exciting new opportunities are discussed in sections 6 and 7. Their impacts are highly uncertain, and for this reason some discretion in auctioning firm power is required for system operators, as discussed in section 8.

39. While all these factors will change the nature of the security of supply problem in the coming decade and beyond, the security problem is not likely to go away, and there will continue to be a need for a significant capacity margin on the system for the foreseeable future. The scale of the capacity requirements as coal plant come off the system are set out in section 5.

40. To these basic firm power security requirements, new dimensions are being added by technical change. The coming of electric vehicles (EVs) and the contribution of zero marginal cost intermittent renewables, plus smart meters and apps, all open up further markets for non-firm power.

41. These costs of intermittency are significant, but will change over time as storage and demand-side management services and other new technologies develop. They should be on a downward path, and will require a mix of technologies that meet the specific characteristics of the intermittency. An important feature of these costs is that they are not currently borne by those who cause them, and in section 7 I make recommendations for addressing these costs more effectively, and incentivising the management of the current and emerging back-up technologies.

42. Most discussion about security of supply focuses on the physical risk of interruptions. This is of course important, but there are also price effects as the margin tightens towards zero. There is always a price that will match supply and demand. The tighter the margin, the higher up the supply cost curve the system is driven in order to balance supply and demand. Tighter margins mean higher prices, and this will be – and has been – reflected in the wholesale price. It is an issue about the level of the security capacity margin for firm power. The government, in setting the margin, should take account of these price effects alongside physical threats to security of supply. This is discussed further in section 7.

43. There are other dimensions of security of supply beyond the capacity margin. Some technologies raise special issues. For example, nuclear power requires a supply of both new and reprocessed fuels, and this material needs to be protected for both defence and environmental reasons. Gas storage is an issue, especially with the closure of Rough and the running-down of the North Sea production, where fields once absorbed some demand variations.

44. Cyber-attacks could disable energy assets, from transmission to power stations. No major country can consider energy security independent of its military security. A disabled electricity system might bring a country to its knees in a matter of hours. These are extra costs to the system, which require cost-recovery mechanisms. In principle, these may be addressed in part through the capacity auctions and also through the allowed revenues for transmission and distribution. In sections 8 and 11, I explain how system operators should take these into account.

45. The inescapable conclusion is that the wider public and economic interest is best served by an over-supplied electricity system. The costs of too little firm power are asymmetrically greater than those of too much. Resilience is a system property and will not be solved by the disaggregated profit-maximising decisions of individual energy companies. More investment may lower rather than raise the overall costs, once the price impacts on customers are fully taken into account, including the impacts on the wholesale market.

46. The policy question is: how much security and of what type? In this review I recommend a way of dealing with the intermittency implications for security of supply. It still remains to set the overall supply margin, and to regularly review this over time and to take account of the growth of specific types of non-firm power demands. Although it is tempting to try to model this in detail, the actual margin will be determined by a host of exogenous factors, from the economic growth rate and macroeconomic circumstances, through to the shape of domestic demand and behavioural changes.

The other objectives

47. It is a tough ask to get government to define any trade-offs between the two high-level objectives on the one hand, and the cost of energy constraint on the other. To this problem is added a host of ancillary objectives, which can conflict with all of the above.

48. The government has environmental policy objectives for all the main sectors of the economy including the main sources of carbon emissions. These include air quality, agriculture, transport, and water. Although there have been white papers and EU directives on integrated pollution control, in practice much of this environmental policy operates in sectoral silos, and almost all of it was developed before climate change assumed its central role.

49. On other environmental objectives and targets, air quality is directly related to carbon and GHGs. The water pollution from agriculture is caused in part by land use, and the use of energy-intensive

fertilisers and other chemicals, and these in turn affect the ability to sequestrate carbon. On transport there are mobility objectives, road-building programmes, airport runways, and high-speed trains, all with impacts on carbon. A key reason why our cities have violated the EU air quality requirement is that the government (and the EU) encouraged a switch from petrol to diesel. This is a way of meeting the climate change objective. But it turns out to be a bad way to meet the air quality objective – another example of non-integrated pollution policies. The absence of an environment protection agency to bring consistency to these diverse environmental challenges is a significant obstacle.

50. The government also has broader economic policy objectives, notably the *Industrial Strategy* objectives. It has identified a number of sectors which it is minded to promote, and it has an R&D and innovation set of objectives. There are also employment objectives. The Green Deal was, for example, promoted as a way to create 250,000 jobs.

51. There are social and welfare objectives, including the elimination of fuel poverty, and one way to alleviate poverty is to increase consumption of energy by poor households, net of energy efficiency measures. There are a number of energy efficiency objectives and there is the EU Energy Efficiency Directive (2012). Some of these fuel poverty issues are addressed in sections 3 and 10.

52. As noted, there is nothing wrong with having multiple objectives. They do, however, require government to clarify what its security of supply objectives and targets are in addition to the carbon ones, and it needs to address the trade-off between all the other multiple objectives. The political challenge should not be underestimated: every trade-off creates losers as well as winners. But failure to address these issues results in higher costs to households and industry. I recommend in section 12 a simple annual statement of objectives to Parliament, building on the climate change statement already required. This is a key government role in energy policy, leaving the detailed implementation to the system operators and the regulators in the new institutional structure set out in sections 8 and 11.

53. In considering other objectives, the government should conduct not only the conventional policy assessments, but have in mind an aggregate carbon constraint. As and when other objectives lead to higher emissions, consideration should be given to offsetting carbon reduction elsewhere, so the overall carbon budgets pathway is not undermined.

MAIN FINDINGS AND RECOMMENDATIONS

- The CCC should give greater weight to the prospect of rapid technical progress in future carbon budgets and take into account the possibility of falling gas prices.
- The CCC should consider in more detail greater contributions from agriculture, and these should be integrated into the 25 Year Environment Plan.
- The government should consider how to develop and enhance integrated pollution control to bring greater consistency between the CCA targets and the other policy objectives.
- The government should set out in a formal annual statement its position on the security of supply margin, and this statement should constitute formal guidance to the system operators.

3. Constraints: Household and Industry Bills, the USO and the Ability to Pay

This section addresses:

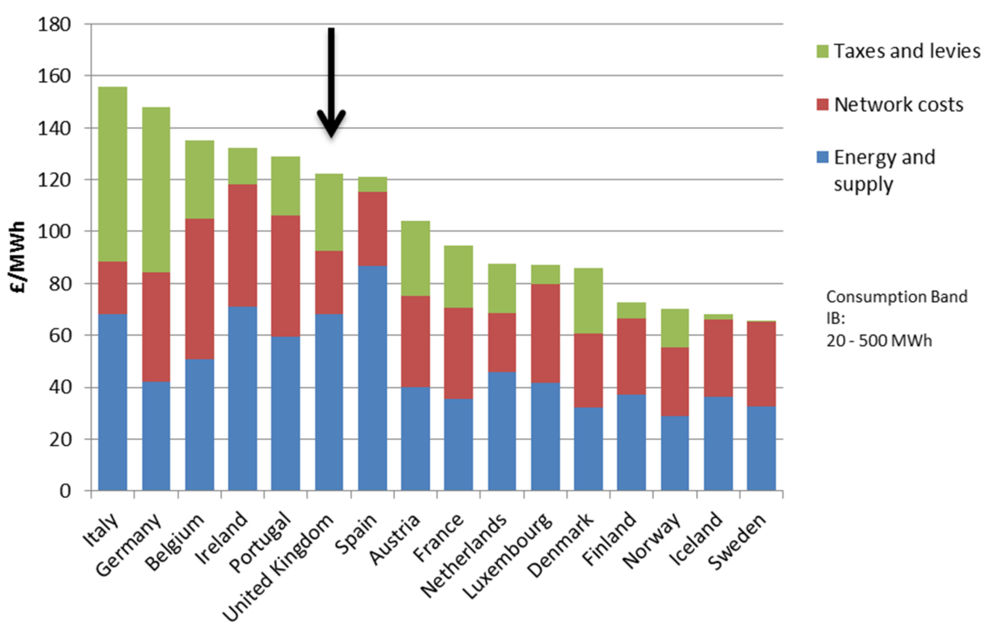
- **the bills – what households and businesses pay**
- **the European comparators**
- **the universal service obligation and other non-price considerations**
- **fuel poverty**
- **options for allocating the fixed costs between different consumer groups and between customers and businesses**

1. The government has a commitment to the UK having the lowest-cost electricity in the EU. As discussed in section 2, this is subject to the achievement of the high-level objectives of climate change and security of supply. It is a constraint.

> *Our ambition is that the UK should have the lowest energy costs in Europe, both for households and businesses.*
> Conservative Party manifesto, 2017

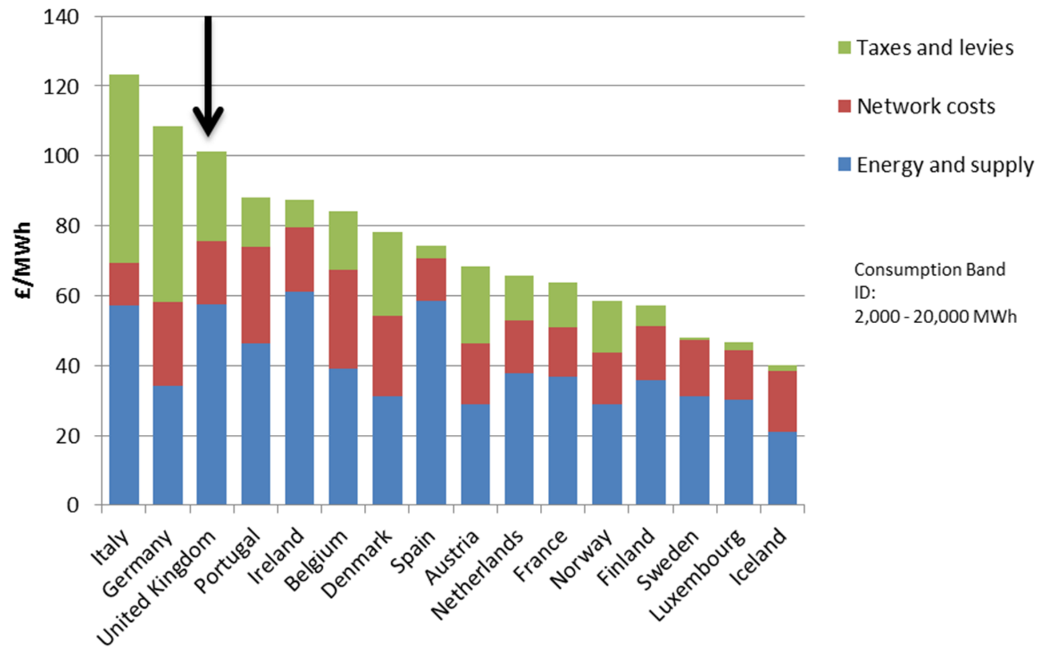
2. The current position in the Eurostat numbers is shown in the following charts comparing electricity price components among major European countries.

FIGURE 6: ELECTRICITY PRICE COMPONENTS: SMALL INDUSTRIAL CONSUMERS



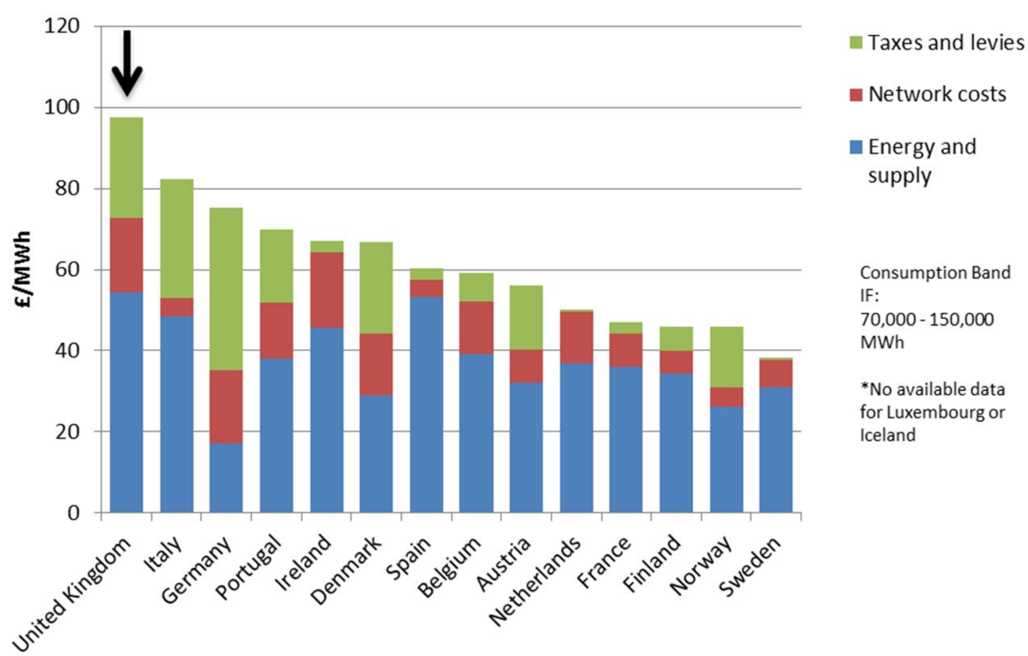
Source: Eurostat database.

FIGURE 7: ELECTRICITY PRICE COMPONENTS: MEDIUM INDUSTRIAL CONSUMERS



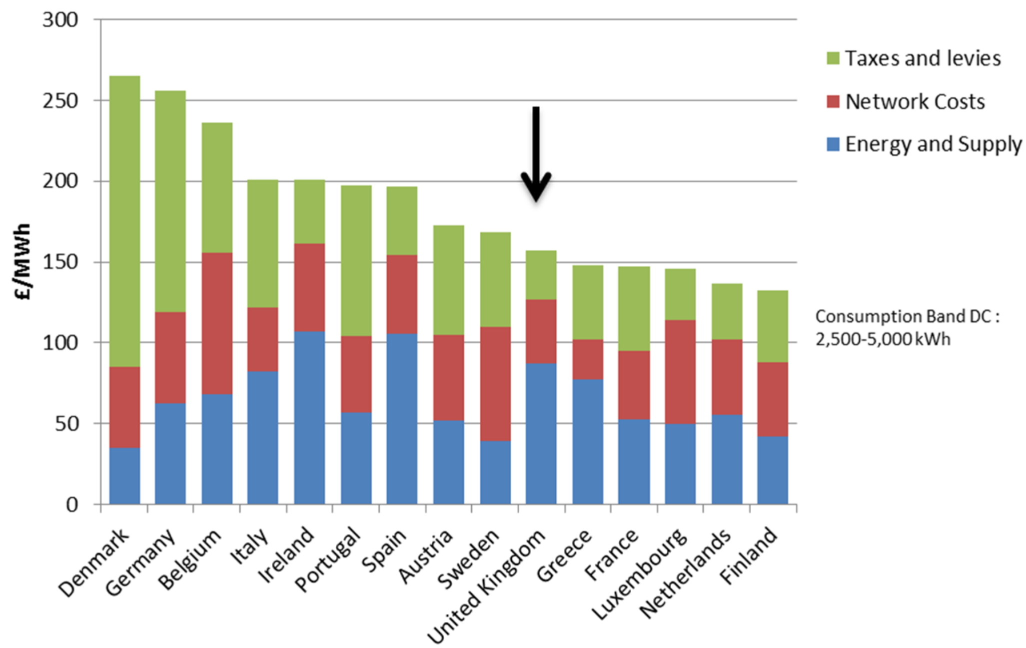
Source: Eurostat database.

FIGURE 8: ELECTRICITY PRICE COMPONENTS: EXTRA-LARGE INDUSTRIAL CONSUMERS



Source: Eurostat database.

FIGURE 9: ELECTRICITY PRICE COMPONENTS: HOUSEHOLD CONSUMERS



Source: Eurostat database.

3. Comparing the costs faced by households and businesses with those of other EU member states is an important check on the costs of energy and competitiveness. These particular Eurostat numbers should be treated with caution: like all such rankings, this is a function of which costs are included, how they are measured, and especially how they are reported.

4. It is the responsibility of the reporting authorities to provide timely, complete, and correct national electricity and natural gas prices to Eurostat. Since it might be advantageous for each member state to appear towards the bottom of the price rankings, there is a natural incentive to report and measure in a way that best represents each country.

5. Even putting these reporting problems aside, it is important to recognise that there is no single price of electricity, and there is no single right answer. It depends on how fixed costs are accounted for; whether the electricity system is pay-as-you-go or pay-when-delivered; and how issues like depreciation and capital maintenance are dealt with – including capitalisation. There is no *fully* common accounting framework for EU transmission and distribution assets; there is no common valuation for regulatory asset bases (RABs); and the reported wholesale prices and payments for capacity and FiTs vary from country to country. I set out some of these accounting issues in the box below.

KEY ACCOUNTING ISSUES IN COMPARING ELECTRICITY PRICES

- Current cost versus historic cost.
- Modern equivalent assets versus construction costs.
- Capital maintenance versus depreciation.
- Privatisation values rolled forward versus market values.
- Treatment of quoted and unquoted companies.
- Treatment of publicly owned assets.
- Regulatory accounting rules.
- Capitalisation policies, operating expenditure (OPEX) and capital expenditure (CAPEX) definitions.

6. The Eurostat numbers should therefore to be treated as one limited indicator. If the government wishes to keep to its aim of being the cheapest in Europe, I recommend that it should create a more sophisticated set of comparators.

Price is only one dimension: the USO

7. The demand for energy is a derived demand. We want energy not for its own sake, but for what it can do for us. Energy is a primary good: without it, citizens will not have the capability to participate in society. Companies, government and other organisations similarly cannot function in the economy without good energy supplies at reasonable costs.

8. It is for this reason that energy has never been a purely private market commodity. Contrary to many claims at privatisation, energy was never going to become just another commodity. This was a basic mistake at privatisation. It, like access to clean water and sewerage, broadband, roads and railways, is always going to be special. As a primary good, the electricity system comprises one of the core primary assets in the economy.

9. For normal commodities, demand represents the willingness and ability to pay for the services. This simple approach is complicated in electricity by a number of considerations, but most importantly that the inability to pay for at least some level of service cannot in a civilised society result in the denial of access to electricity. Similarly, if companies cannot access supplies at reasonable cost, they may go bust, and the economy as a whole suffers.

10. The requirement for access to the services is a universal service obligation (USO) – something that no private market would commit to without intervention. The development of electricity networks and supplies over the 20th century was a process of extending electricity to the more remote parts of the economy, on the very good grounds that this is what a decent society and a modern economy necessitates. Competition and markets are means to this end, not the end in themselves.

11. The challenge is to modernise the USO for the energy transition, and to consider two specific questions: what should the services include? And who should pay what for them?

12. The USO is an entitlement to access to a supply of electricity. Access means not just connections but the ability to pay. There are a host of special arrangements for poorer consumers. As technology changes, so too does the USO.

13. In particular, as transport electrifies, universal access to charging facilities will become increasingly important. In a mid-21st-century world without petrol and diesel cars, access to transport will require access to charging facilities. As the line between generation, distribution and supply blurs, the right of access to decentralised systems may become important. Section 6 looks at the specific needs of an electric transport world, and some of the implications for the cost of energy.

14. The government has effectively made the right to the offer of a smart meter a new USO. This is part of the digitalisation of energy services also described in section 6.

15. The coming of smart technology means that the electricity industry requires the information infrastructure to support smart meters, and to enable all customers to take advantage of the new apps and opportunities for smart appliances and smart buildings. A related USO is for broadband access, although this is not yet a legal requirement. In order for the cost of energy to be optimised in this new smart world, broadband needs to be capable of supporting these options, and at the same time support the other USOs.

16. With a modernised USO, and one that is flexibly changing as the technologies change, a key question is: who should pay what contributions to the fixed costs of the emerging electricity systems? As section 6 describes, the new digital world is one of increasing zero marginal cost, and in a zero marginal cost world, the charges to extract the required fixed-cost revenues on different classes of consumer are a matter of choice.

17. In a perfectly competitive ideal, and if efficiency is the only objective, economic theory suggests that these charges should follow the Ramsey rule: the price charged to different consumers should

be inversely related to their demand elasticities. This means that the more important the supply is to you, the greater the contribution you should pay towards the fixed costs (which will become an increasing proportion of the total costs). Put simply, the more committed and loyal a customer, the more they should pay. This is indeed what has been happening with the Standard Variable Tariff (SVT) discussed in section 9.

18. We do not live in a world where all that matters is efficiency. The concept of rewarding the more elastic switchers, while loyal customers face higher prices, is not only going to get more difficult in a situation where there is little to switch from (since the costs will increasingly be fixed), but also undermines the importance of citizenship, capabilities, functions, and inclusion. For the wider economy, this approach is also found wanting. The added risk of subjecting loyal customers to higher charges is that the principle of fairness is undermined, not only reducing trust, but also threatening the commitment to decarbonisation among the wider public.

19. In section 9 I recommend the adoption of a default tariff which transparently passes through the fixed costs, including the legacy costs I identify in section 5. This default tariff leaves open how to allocate the pass-throughs between the customer classes.

20. The current allocation of fixed costs, and the current total electricity costs faced by households and industrial customers, have been the subject of much debate and controversy in recent years. All main political parties have proposed interventions for reasons other than pure efficiency. They have been right to be concerned, although some of the many proposed interventions have been confused.

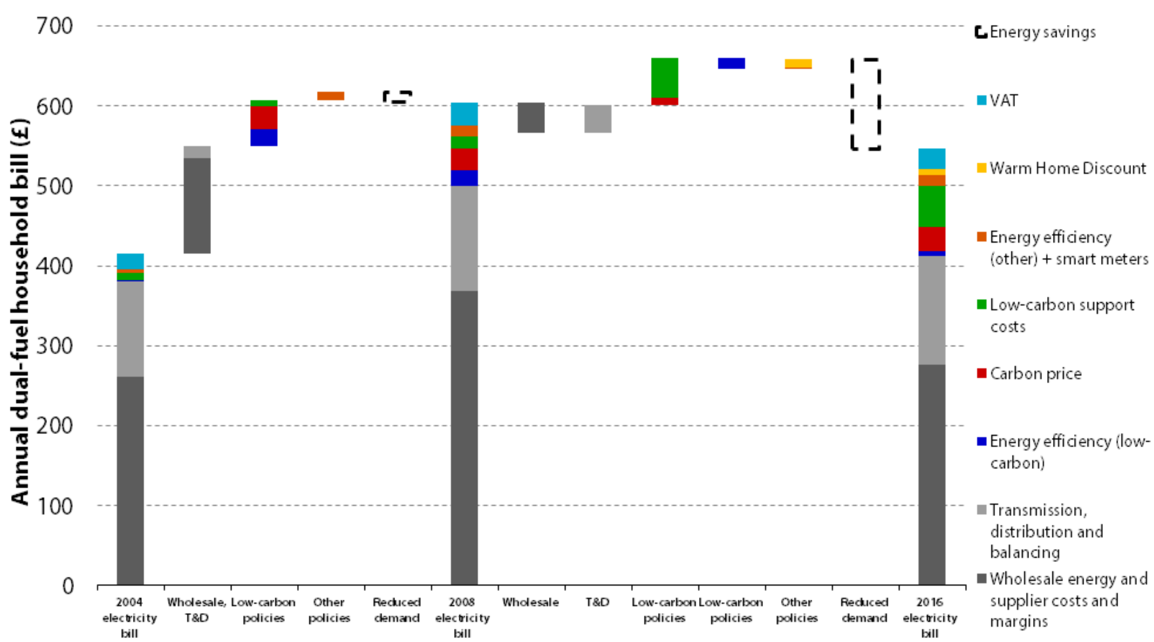
Current household and industry costs

21. The starting point is to establish the impact of energy costs on household budgets and, in particular, the household budgets of two groups: the average and the least well-off. The former is a statistical exercise focused on the mean and the medium households, and is the one typically quoted, and typically too for dual-fuel bills. Other measures could try to disaggregate to an individual level, and take a broader perspective on incomes to define this category. All customers are in one sense unique, but there needs to be an aggregation to get at the detriments from market power and to come up with remedies. The average household's total income before tax is just over £40,000 and after tax around £33,000. Electricity bills comprise 1.78% (about £600) of after-tax income.

22. Defining which households are poor is an altogether more complex task. Poverty has both absolute and relative dimensions, and the definition used for fuel poverty is particularly contentious. Nevertheless, we have to start from somewhere, and asking a simple question about how many households spend more than 5% or 10% of their incomes on electricity has some merit. For what the policy is concerned with is working out who will be hit hardest by price increases, and who will benefit if and when prices fall. The application of a price cap to a specifically identified group requires a definition and the data to support it. The more general the price cap, the less important this question.

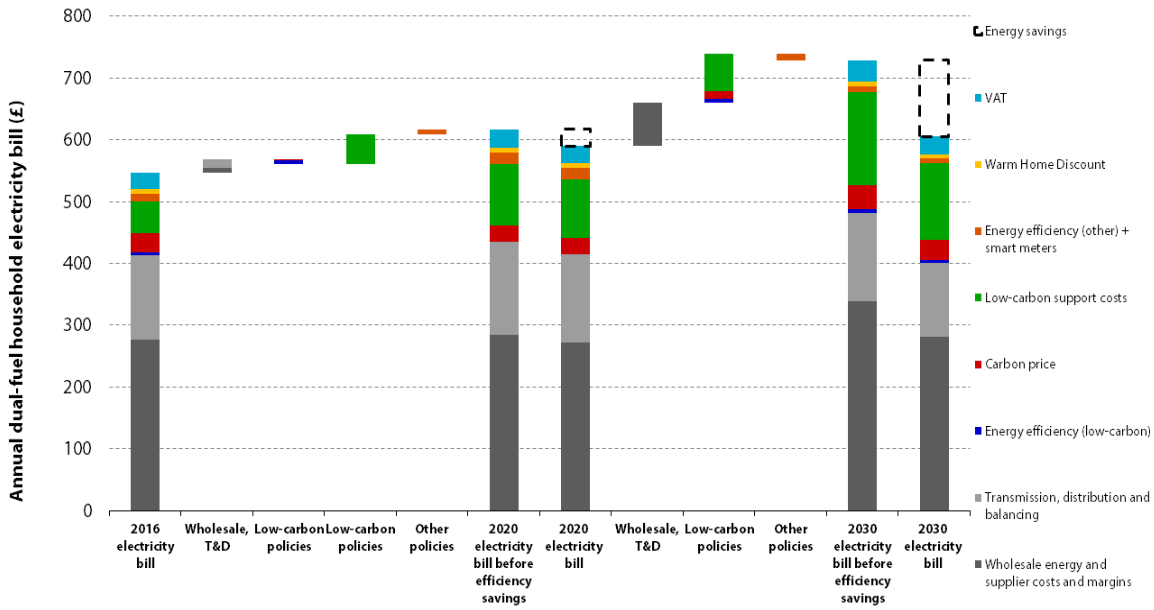
23. The chart below indicates which cost increases have contributed to the bills over the period from 2004 to 2016. The wholesale costs have fallen sharply since 2014 as oil, gas and coal prices fell back, but the benefit which customers might have expected has been swallowed up by policy costs, networks and margins. Many of these are what will be described as legacy costs, and in section 5 I set out how these might be ring-fenced.

FIGURE 10: CHANGES IN DUAL-FUEL HOUSEHOLD ELECTRICITY BILLS (2004–2008–2016)



Source: CCC analysis, Figure A2.1, available at https://www.theccc.org.uk/wp-content/uploads/2017/03/Energy-Prices-and-Bills-Committee-on-Climate-Change-March-2017-Annex.pdf.

FIGURE 11: CHANGES IN DUAL-FUEL HOUSEHOLD ELECTRICITY BILLS (2016–2020–2030)



Source: CCC analysis, Figure A2.3, available at https://www.theccc.org.uk/wp-content/uploads/2017/03/Energy-Prices-and-Bills-Committee-on-Climate-Change-March-2017-Annex.pdf.

24. Most discussion about the impacts of increases in electricity bills is only about electricity bills. But for households, electricity bills are just one among many outgoings, alongside other utility bills, transport, food, Council Tax and other taxes, and the cost of housing. The ability to pay is a general problem for households, as well as specifically in respect of electricity.

25. In the coming years, it would be reasonable to assume that the extraordinary monetary interventions following the crash in 2007/08 may gradually come to an end, and that would mean a return to normal interest rates. For the purposes of this discussion, we can consider these to be around 1–2% above the inflation rate. Add in the level of credit card debt, car finance debt and mortgage debt, together with a subdued position for wages and income growth, and it is apparent that many households will struggle to absorb this interest rate increase. This matters because it leaves less room for households to pay for electricity, and as a result less willingness and ability to pay for decarbonisation measures. It makes the cost of energy more likely to become a binding constraint.

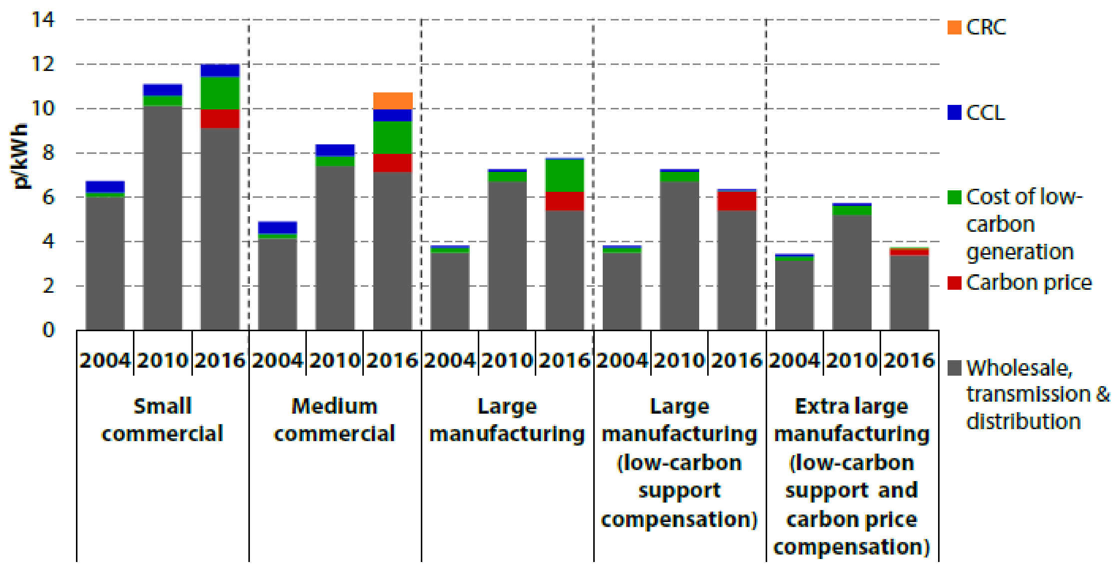
26. In this review I look at the costs of each part of the supply chain which makes up the electricity bill (sections 7, 8, 9, and 10). I note the scale of the policy costs, levies and other direct interventions, and what they mean for customers' bills, when set against the household budgets.

27. What this tells us is that if the costs of current and future interventions are maintained or increased, it is likely that some customers will struggle. Some simply will not be able to pay, and if they can, they may not be willing do so. There is only so much of a premium that can be put on top of the current bills in a democracy. I recommend below and in sections 5 and 10 ways that this might be addressed.

28. Industrial bills are harder to calculate since they are heterogeneous, and have a wider variety of strategies and choices available to them. There is no 'typical' business.

29. The following charts illustrate the breakdown of the costs of electricity by size and by other characteristics.

FIGURE 12: CHANGES IN ELECTRICITY PRICES FOR ILLUSTRATIVE BUSINESSES (PURCHASED VIA A SUPPLIER, 2004–2010–2016)



Source: CCC analysis, Figure 2.7, https://www.theccc.org.uk/publication/energy-prices-and-bills-report-2017/.

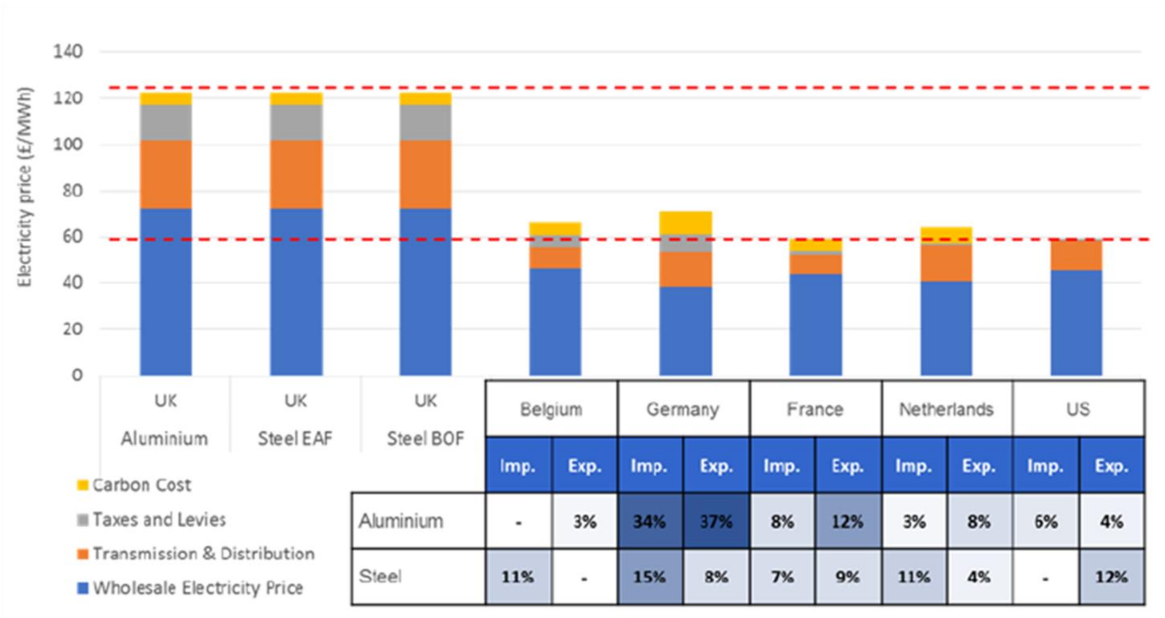
Notes: 'Cost of low-carbon generation' is the net cost of policies to support low-carbon generation, which include costs under the Renewables Obligation (RO), FiTs and CfDs and intermittency costs, offset by the merit order effect (which reduces the wholesale price, but is considered as a low-carbon policy benefit). CRC, Carbon Reduction Commitment.

30. The chart above indicates how the cost to industry has risen – again to a significant degree because of the policy costs. Only extra-large manufacturing has received some significant protection. Facing low policy costs and low carbon costs, US companies continue to benefit from lower electricity costs compared with the other competitor countries in the projected period in the chart below. Higher

relative wholesale prices also drive an increase in the overall price and, again, US industries benefit from a lower wholesale gas price and, therefore, lower wholesale electricity prices. As the chart below illustrates, industrial electricity prices in the UK remain the highest among the competitor countries.

31. In sections 5 and 10 I recommend that industrial customers should be exempt from legacy costs, and a number of other complex mechanisms which have built up in the energy taxes and levies that industry pays – but not from paying the cost of carbon. This should be applied both domestically and at the border, and in this way its impact on competitiveness is neutralised.

FIGURE 13: 2030 ELECTRICITY PRICES FOR INDUSTRIES CONSUMING >50GWH OF ELECTRICITY PA WITH EU EMISSIONS TRADING SYSTEM COMPENSATION



Source: Figure 2.8 of Cambridge Econometrics, (2017), 'Competitiveness Impacts of Carbon Policies on UK Energy-intensive Industrial Sectors to 2030', March. Available at https://www.theccc.org.uk/wp-content/uploads/2017/04/Competitiveness-impacts-on-energy-intensive-industries-Cambridge-Econometrics-March-2017.pdf.

Notes: Dashed red lines show minimum and maximum electricity prices faced by Profile 3 industries across all countries considered. The table under the chart shows, for each sub-sector, the share of total imports and total exports to the UK that is attributable to each partner country.

Alternative ways of allocating the fixed system costs across retail and wholesale customers

32. Section 6 describes how the variable costs diminish over the technological transition. There will be increasing choice about the allocation of the fixed system costs (in addition to the issues in relation

to legacy costs dealt with in section 5). The first step is to define an appropriate accounting base, to sort out depreciation, capital maintenance, capitalisation and asset lives. This then allows the total fixed system costs to be charged to the various classes of customer to be identified. It is not a competition issue, and is not addressed by switching: the system costs are fixed.

33. The next step is to decide the charging principle. Since no one can escape the system costs, except possibly by opting out of the system entirely, there is a choice, and it is necessarily political. The government needs to give urgent consideration to how charging will develop.

34. There are at least six options (not all mutually exclusive), as follows:

(i) Charge according to the economic efficiency criterion set out by Ramsey. Ramsey pricing allocates fixed costs inversely to the demand elasticity. The aim is to recover the costs in ways that minimise the resulting efficiency distortions. It is, for example, the rationale that might be offered for charging loyal customers more through the SVT than those who switch, and less to internationally competitive companies.

(ii) Recover on a purely volume-of-consumption basis. The problem with this approach is that it confuses the price of capacity and systems with the marginal incentives to consume extra units of energy.

(iii) Recover the costs through a fixed charge, like a standing charge – a capacity or access charge.

(iv) Charge according to ability to pay. This is the option in which fuel poverty could be taken directly into account, and could work in several ways. It could apply a reduction to the poorest customers (the 5% or 10% category); be linked to some other income indicator; or employed as a rising block tariff as volumes rise (see below), thereby increasing the price as the consumption goes up.

(v) Use industrial policy. This could explicitly apply short-run marginal cost (SRMC) pricing to large industrial companies, and the average costs to the rest of the customer base.

(vi) Charge an initial minimum block, followed by demand-related charges.

35. These issues will become urgent in the next decade, as new systems are developed at a more local level, and as new network provisions are required – for example, the transport charging network. Again, the general default tariff I recommend in section 9 is relevant.

36. The implication of this shift towards fixed costs is that switching is going to apply to an increasingly narrow section of the cost base. Smart meters will be useful for the system operators to coordinate and manage demands, for the new and emerging energy service businesses, and with a view to

saving system costs, but they will be less and less relevant to switching on the basis of wholesale costs – because these will be an ever-diminishing part of total costs. Competition will focus instead on capacity and capacity packages, defined on the basis of maximum volumes. This might more closely resemble the current broadband and mobile pricing packages.

37. The main elements of competition – discussed in this review – will increasingly focus on delivering the capacity, not the energy. I make recommendations on this in section 7.

38. With a capacity package approach, one option to address part of the fuel poverty problem is to provide a basic block of energy to all households, with the rest of the system fixed costs passed through to consumers above this basic level – option (vi) above. It is possible to consider the basic provision and its pricing as part of the USO and hence as a universal entitlement. This could take the form of an exemption from the legacy costs (as with industry) and a discount on other fixed elements. I recommend that government should review the options set out above and, in particular, a basic block approach and exemptions approach.

MAIN FINDINGS AND RECOMMENDATIONS

- The government should create and monitor a more sophisticated set of price and cost comparators beyond the Eurostat approach.
- The broadband USO requirements should be assessed alongside the smart meter roll-out. BEIS and the Department for Digital, Culture, Media & Sport should coordinate the timings and scales of these investments.
- The government should consider the allocation of the system costs and, in particular, the option of providing for a basic block of electricity capacity at a lower fixed cost to address fuel poverty.

4. Current Policy Interventions and Forecasting

This section addresses:

- **the mass of interventions**
- **why complexity is expensive**
- **why conventional cost–benefit assessments are misleading**
- **policy and regulatory capture and its link to complexity**
- **why simplification is a key priority if the cost of energy is to come down**
- **why a piecemeal intervention-by-intervention retreat is not optimal**
- **the limits and failures of DECC and BEIS forecasting**

1. Just as there is no shortage of objectives, there is similarly no shortage of policy interventions. As with objectives, in principle, there is nothing wrong in having lots of interventions, *provided* they are consistent with the objectives and do not create unintended negative consequences, and are not perverse. In practice, the complexity and inconsistency of current interventions that has built up as a result of a sequence of *ad hoc* policies is a major source of inefficiency and has created excessive costs. It will be hard to reduce the costs of energy without a radical simplification of the multiple interventions.

2. The sheer number of interventions in the UK energy market is so great that few if any participants in the markets, few regulators, ministers or civil servants can have grasped them all. The inability of the market participants to grasp all these interventions is in itself likely to increase the cost of energy.

3. In addition, it is highly unlikely that many of them are optimal, although it is hard to form firm judgements because the myriad interventions interact with each other in ways that stretch any policy analysis or cost–benefit test. The result is that it is not possible to make a cost-effectiveness assessment of almost any of the specific policies, despite numerous claims in particular cases. Each partial silo analysis typically leaves out the impacts on all the rest of the energy sector, and indeed other parts of the economy too.

4. Complexity has significant additional costs for energy, because the greater the complexity, the greater the scope for capture by rent-seeking lobbyists and interest groups. Each intervention changes returns. Once gained, they tend to get capitalised. As a result, any moves to reform and change arrangements – for example, by phasing out particular subsidies – creates losers, and often capital losses. Understandably these are resisted, and the complexity makes it much easier to

protect specific interests, while at the same time reducing the ability of households and industrial users to defend their general interests in general efficiency. It is no accident that the growth of complexity has been closely matched by a growth in lobbying (and vice versa), and that much of the debate about subsidies has become toxic.

5. To get a handle on the complexity, I asked BEIS to provide me with a list of all the main current interventions. It runs to several pages, and is almost certainly incomplete. The main current interventions BEIS listed are as follows.

TABLE 1: CURRENT POLICIES AND INTERVENTIONS

	Start	End
Small-scale feed-in tariff (ssFiT) – introduced in 2010 under the Energy Act 2008 to encourage deployment of small-scale low-carbon electricity generation by households and organisations not traditionally involved in energy production. Technologies supported are: solar photovoltaics (PV), onshore wind, hydropower, anaerobic digestion, and micro-combined heat and power (CHP).	April 2010	Current budget covers the period to March 2019
Renewables Obligation (RO) – an obligation on UK electricity suppliers to source a specified proportion, set each year for the year ahead, of the electricity they supply to customers from renewable sources. Administered by Ofgem, which issues ROCs to generators in relation to the renewable electricity they generate. Closed to new entrants on 31st March 2017 with limited grace periods.	April 2002	Closed to new entrants on 31st March 2017
Contracts for difference (CfDs) – introduced in 2014 under the Energy Act (2013), this is a private law contract between a low-carbon electricity generator and the Low Carbon Contracts Company, a government-owned company. A generator is paid the difference between the strike price and the reference price; the cost is met by consumers via a levy on electricity suppliers. To date, CfDs have been allocated through: – Final Investment Decision enabling Round; – Pot 1 auction for established technologies; – Two Pot 2 auctions for less established technologies; – Bilateral negotiations for Hinkley Point C.	2014	Ongoing
Carbon Price Floor (CPF) – price charged on CO_2 emissions. UK prices are determined by the EU Emissions Trading System (ETS) and Carbon Price Support (CPS). Starting in 2021–22, the government will target a total carbon price and set the specific tax rate at a later date, giving businesses greater clarity on the total price they will pay.	April 2013	Total carbon price from 2021–22
Capacity market – BEIS establishes security of electricity supply by ensuring that regular payments are available to reliable sources of capacity, so that energy is reliably delivered when needed	First auction 2014	Auctions annually

	Start	End
Environmental regulations – various environmental regulations also cover installations in the power sector, such as the Large Combustion Plant Directive and the Industrial Emissions Directive	Various	Ongoing
Emissions Performance Standard – a regulatory backstop to the National Planning policy, and ensuring that not only are new coal plant built with carbon capture and storage, but are operated in accordance with emissions requirements.	2015	Ongoing
Connections – the Connect and Manage policy allows new generation to connect to the grid faster, with wider network reinforcement carried out after they have been connected.	May 2009	Ongoing
Third Energy Package – EU legislation that provides the basis for the European internal energy market.	March 2011	Ongoing
Smart Metering Implementation Programme – a mandate on energy suppliers to take all reasonable steps to roll out electricity and gas smart meters to all homes and small businesses in Great Britain by the end of 2020; to provide accurate bills, increased consumer engagement with energy consumption, and a smarter energy system.	2011	2020
Current RIIO (Revenue = Incentives + Innovation + Outputs) price controls – Ofgem's framework for determining the allowed expenditure and associated revenues, for the monopoly electricity and gas network companies.	2013	2023
Interconnection – BEIS promotes interconnection where it is in the interest of consumers. Ofgem provides a 'cap and floor' system, which facilitates a predictable rate of return for interconnectors.	2013	Ongoing
Market liquidity – Ofgem's Secure and Promote measures to improve liquidity and access to the wholesale electricity market by requiring the largest generating companies to follow a set of 'Supplier Market Access' rules when trading with small independent suppliers.	March 2014	Ongoing
Sharper market signals – making wholesale prices more responsive to scarcity by ensuring that cash-out prices are reformed, creating the correct signals for the market to balance.	April 2015	Ongoing

	Start	End
Reform of the System Operator: Ofgem is working with National Grid to make the electricity system operator a legally separate company within National Grid.	January 2017	April 2019
Locational pricing – Ofgem has confirmed implementation of the Competition & Markets Authority's (CMA) recommendation for location pricing for network losses.	April 2018	Ongoing
Codes and licences – many activities in energy require a licence from Ofgem as well as compliance with industry-led codes.	Various	Ongoing

Source: BEIS.

TABLE 2: POLICY DEVELOPMENT

	Start	End
Industry Code Governance reform – Ofgem is leading implementation of CMA recommendations to support strategic industry change.	February 2017	New consultative board operational Q1/2 2018
Coal power and clean growth – end use of coal for electricity generation by 2025.	2017	2025
RIIO–2 price control – Ofgem's planning for the next round of price controls, for monopoly electricity and gas network companies.	July 2017	Ongoing (2021 implemented)
Industry technical standards – standards across electricity and gas were designed many years ago and may be encouraging overinvestment given improvements in technology. For example, P2-6 electricity standards, or British gas quality specifications.	Continuous process	
Switching – BEIS is working with Ofgem to take forward a number of initiatives designed to make it easier for customers to switch energy suppliers. This includes proposals by Ofgem for delivering next-day switching, published in its consultation on 21st September 2017.	Continuous process	
Network charging – Ofgem is responsible for making changes to the way that network costs are recovered to ensure recovery is cost-reflective. Ofgem's targeted charging review has set out options for residual network cost recovery.	Continuous process	
Locational signals – Ofgem will publish a working paper in autumn 2017 on how to provide users with improved signals about the incremental costs and benefits of their network usage, either through charging signals, changes to market design, or market access reform	Autumn 2017	Ongoing

	Start	End
Smart Energy – BEIS is working with Ofgem to manage the transition to a smarter system, where the department's role is to establish the policy and legal framework, enabling Ofgem to regulate the sector accordingly. (BEIS and Ofgem (2016), 'A Smart, Flexible Energy System: Call for Evidence', November; BEIS and Ofgem (2017), 'A Smart, Flexible Energy System: Question Summaries and Response from Government and Ofgem', July; BEIS and Ofgem (2017), 'Upgrading Our Energy System: Smart Systems and Flexibility Plan', July. See summary of the plan below:	2016	Ongoing
– **Removing barriers to smart technologies** – providing regulatory clarity and a fairer charging system to encourage growth of the sector, particularly for energy storage.	2016	Ongoing
– **Smart homes and businesses** – delivering the necessary infrastructure and system enablers for further growth in this sector, such as time-of-use pricing and appliance standards to enable automation and ensure cyber security.	2016	Ongoing
– **Markets that work for flexibility** – improving access to markets (eg, capacity market, balancing mechanism, ancillary services) for the sector to improve the revenue-stacking potential for smart technologies, and to enable access to new markets such as at a local network level.	2016	Ongoing
The government's *Clean Growth Strategy*, announced in October 2017, sets out a series of low-carbon policies to encourage economic growth while meeting environmental commitments.	Ongoing	-

Source: BEIS.

6. BEIS's initial list of policies and interventions has been kept to a high level in the first instance. It is the tip of the iceberg. In addition, there are numerous regulatory rules, codes, licences, and other interventions.

7. Understanding, compliance and lobbying have created numerous costs on companies (consumers do not really have the opportunity to significantly influence the details). Every main energy company and every main energy-consuming company has its own regulatory team, and a number of significant and in some cases highly effective trade bodies have emerged. Most of this is deadweight welfare loss, both directly in the administrative costs and more seriously in the resulting allocative distortions. My proposals for a long-term framework are designed to sharply reduce this burden. It is intended to be as lobby-proof as possible. As a result, many vested interests will not welcome reduction in their scope for lobbying and capture.

8. There are lots of major official bodies and organisations running this mass of interventions. The short list includes:

- BEIS
- HM Treasury (energy and carbon taxation, and public expenditure)
- Carbon Trust
- Committee on Climate Change
- Committee on Fuel Poverty
- Crown Estate
- Defra
- Department for the Economy (Northern Ireland)
- Electricity Market Reform Settlement Limited
- Electricity Settlement Company
- Environment Agency
- European Commission
- Health & Safety Executive
- Low Carbon Contracts Company
- National Grid
- Office for Nuclear Regulation
- Ofgem

9. For each intervention there is a long list of policies, regulations and strategies – to add to the three pages above from BEIS. It would be beyond the comprehension of any civil servant, minister or participant in these markets. A classic feature of capture holds: the particular interested party would have superior information. Asymmetric information between the government and regulators on the one hand, and the vested interest on the other, is a bigger problem, the more complex the interventions. Yet almost every measure on the long list would have some party who would want to defend and protect it. The opposition to piecemeal reform is likely, therefore, to be tortuous, and this is why it is imperative to go back to first principles, which is what the long-term framework I set out in section 11 does.

10. A further example of complexity is illustrated by the multiple interventions to address energy efficiency. The short list is set out below.

TABLE 3: ENERGY EFFICIENCY SCHEMES

Scheme	Description
Public Sector Energy Efficiency Loans Scheme	Interest-free loans to public sector bodies in England to undertake energy efficiency works
Re:Fit	Procurement framework for public bodies undertaking energy efficiency and generation works
Products policy	UK implementation of EU directive on energy performance of energy-using products
Green Government Commitment	Targets for government departments and agencies to reduce their environmental impact, including carbon emissions
Climate Change Levy	Tax on energy supply to business and public sector consumers
Climate Change Agreements	Voluntary agreements undertaken by organisations subject to the CCL to reduce emissions, thus qualifying for a reduced CCL rate
CRC Energy Efficiency Scheme	Requirement on large energy consumers to buy emission allowances and provide evidence on their energy consumption
Energy Saving Opportunity Scheme	Requirement on businesses and public sector organisations to undertake quadrennial energy use audits and identify measures that could improve energy efficiency
Smart Metering	Programme to roll out smart meters to all domestic and small business consumers
Energy Company Obligation	Requirement on large domestic energy suppliers to achieve carbon and bill savings through the installation of energy-saving measures in domestic properties
Private Rented Sector Regulations	Requirement that from 1st April 2018 any properties rented out in the domestic and non-domestic private rented sector must have a minimum energy performance rating of E on an Energy Performance Certificate
Building Regulations	The Building Regulations set minimum energy performance standards for new buildings and when building work is carried out to existing properties

Source: UK National Energy Efficiency Action Plan, 28th April 2017, available at https://ec.europa.eu/energy/sites/ener/files/documents/uk_neeap_2017.pdf.

Notes: More comprehensive information is available in Annex A of the UK's National Energy Efficiency Action Plan.

Forecasting and modelling to support the interventions

11. To support the various interventions, and especially the ROCs, FiTs and the low-carbon CfDs, BEIS, and the Department of Energy and Climate Change (DECC) before it, produces fossil fuel price assumptions and from these the wholesale price assumptions. But assumptions do not come out of thin air: they are in reality forecasts, and I shall treat them as such in this review.

12. If the government is going to get deeply involved in being the central contractor, to contract on a technology-by-technology basis, and run multiple policy interventions, it needs to try to second-guess the results the market would otherwise have produced. It needs to forecast the future.

Conversely, if the government gets out of many of these activities, it does not need to be in the forecasting and modelling business.

13. Those forecasts made between 2010 and 2015 have been particularly poor, and have led to some unsatisfactory decisions. The beliefs held by DECC and its various ministers, particularly as regards peak oil and ever-rising oil, gas and coal prices, led to its 2014 prediction that by 2020 electricity prices would be 7% lower than they would have been without the renewables investments and other policy interventions, including energy efficiency measures. This prediction was based on the assumption of rising and volatile gas prices.

14. DECC could not, however, hold out the prospect of lower electricity prices by 2030, as the legacy costs of its policies kept adding to the bills. The box and chart below set out its analysis and projections through to 2030.

PRICES AND BILLS REPORT 2014 – IMPACT OF POLICIES

The 2014 prices and bills report analysis was based on the 2014 fossil fuel price assumptions. It concluded that by 2020 the average net impact of policies on household energy bills is estimated to be a saving of around £92, or 7% (see table and chart below). This is because although the cost (and resulting impact on bills) of supporting investment in low-carbon technologies is expected to increase, the savings from energy efficiency policies are also expected to increase.

FIGURE 14: IMPACT OF POLICIES ON HOUSEHOLD ENERGY BILLS

Table 2: Summary of estimated average impact of policies on household gas and electricity bills (inc. VAT)

Real 2014 prices	2014	2020	2030[32] (See footnote)
Average **gas bill** without policies	£832	£778	£897
Average **gas bill** with policies	£783	£713	£795
Impact of policies on average **gas bill**	-£49 (-6%)	-£65 (-8%)	-£102 (-11%)
Average **electricity bill** without policies	£627	£633	£689
Average **electricity bill** with policies	£586	£606	£729
Impact of policies on average **electricity bill**	-£41 (-7%)	-£27 (-4%)	£40 (6%)
Average energy bill without policies	**£1,459**	**£1,411**	**£1,586**
Average energy bill with policies	**£1,369**	**£1,319**	**£1,524**
Impact of policies on average energy (gas plus electricity) bill	**-£90 (-6%)**	**-£92 (-7%)**	**-£62 (-4%)**

Source: BEIS.

Chart 7: Estimated household energy bills with and without policies[33] (See footnote for 2030)

Source: DECC (2014). Figures may not sum due to rounding.

15. BEIS is still in the business of producing forecasts with rising fossil fuel prices in the revisions it has subsequently made. The graphs below show the 2016 projections for oil prices, and the 2014 and 2016 projections for gas and coal prices.

FIGURE 15: BEIS 2016 OIL PRICE ASSUMPTIONS

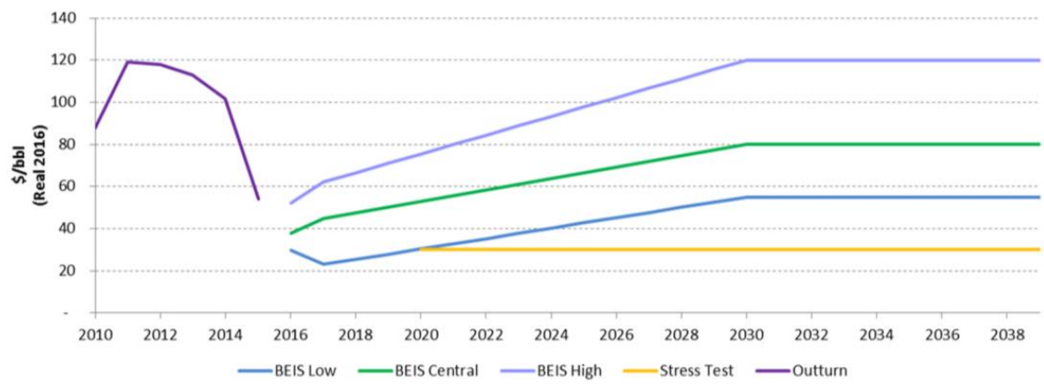


FIGURE 16: BEIS 2014 AND 2016 GAS PRICE ASSUMPTIONS COMPARED

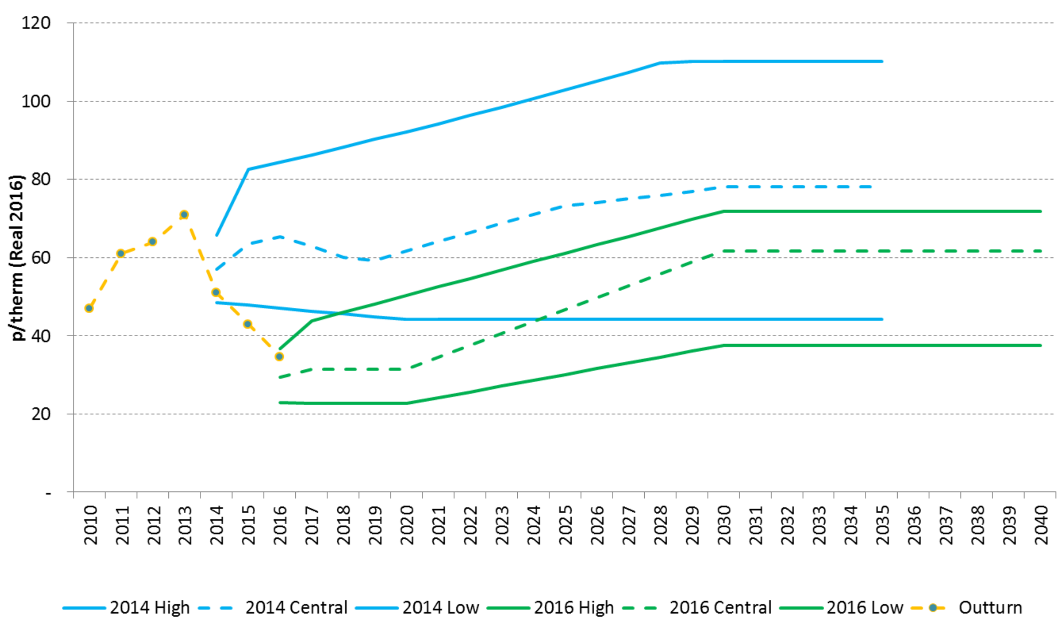
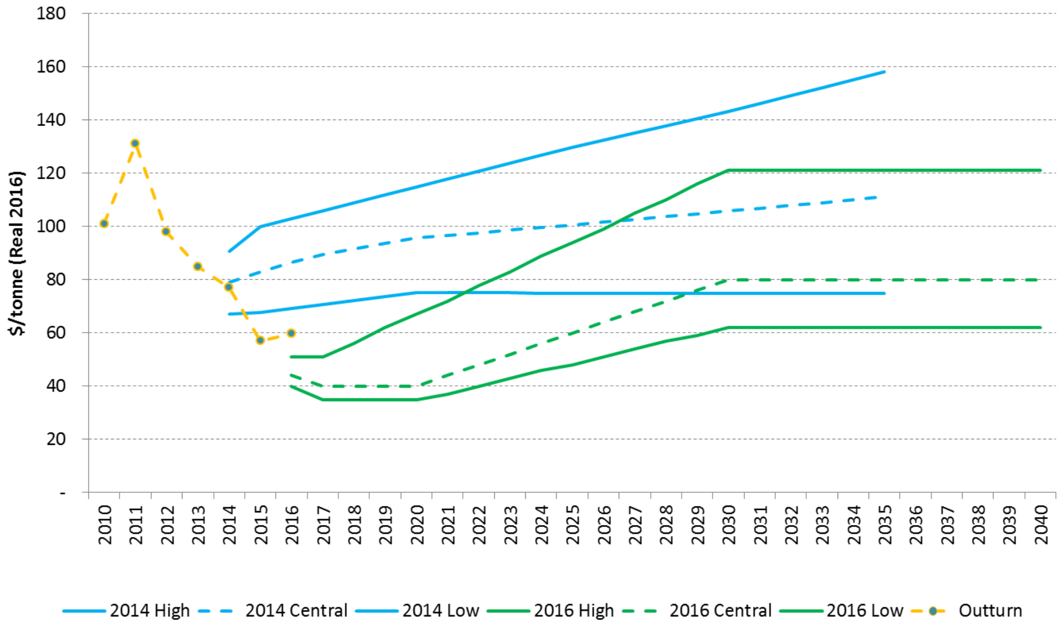


FIGURE 17: BEIS 2014 AND 2016 COAL PRICE ASSUMPTIONS COMPARED



Source: DECC and BEIS (2014, 2016), Fossil fuel price assumptions.

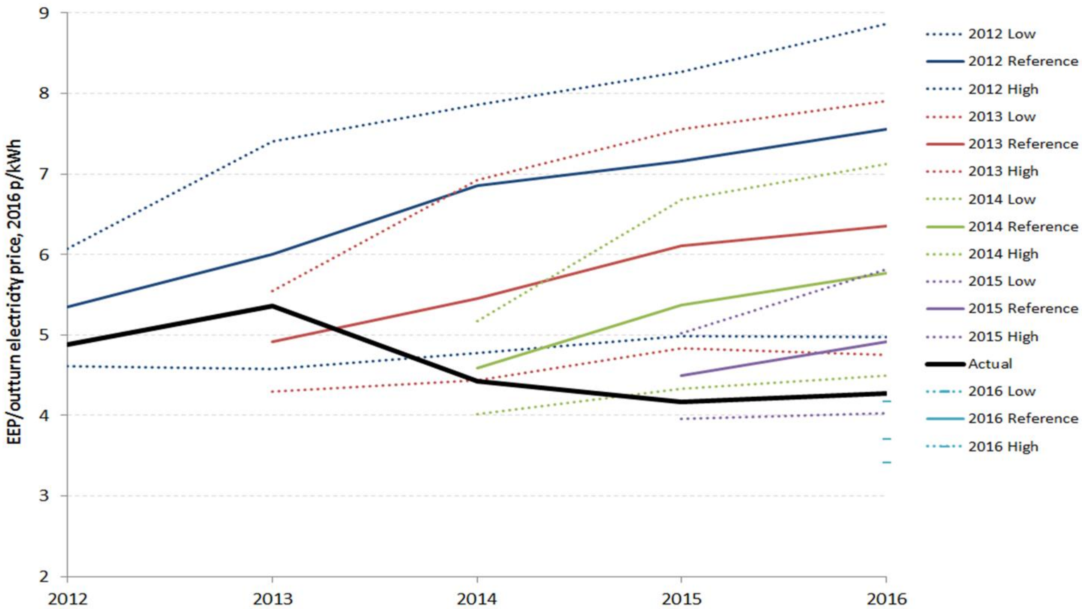
16. These projections jump around a lot. The changes are big, and in themselves illustrate not only the scale of the mistakes, but the risks of relying on them for the purposes of informing BEIS's interventions.

17. What matters is what these projections/assumptions/forecasts are used for. In the electricity sector, the central planning functions that DECC took on with Electricity Market Reform (EMR) necessitated it adjudicating on value for money in granting ROCs, FiTs and low-carbon CfD contracts, and especially once the FiTs (like the ROCs) are banded. In considering whether the CfD for Hinkley or for offshore wind passes the test, in the context of the carbon budgets, a high assumption for gas and coal prices pushes up the predicted wholesale costs (driven by gas and coal prices), and this in turn pushes up the level of the FiT which would be expected to be 'in the money' in respect of the CfD with the wholesale cost. Auctions subsequently showed how wrong these projections were.

18. With this in mind, let us consider the latest BEIS wholesale electricity assumptions. The chart below shows how these have fallen with lower gas price projections, but still shows the wholesale price rising.

DECC/BEIS projections and outcomes

FIGURE 18: DECC/BEIS WHOLESALE ELECTRICITY PRICE PROJECTIONS



Source: DECC and BEIS (2012–16), Fossil fuel price assumptions; BEIS (2017), Energy and emissions projections 2016; HM Treasury (2017), GDP deflators at market prices, and money GDP: March 2017 (Spring Budget 2017).

19. What is remarkable about these assumptions is that they do not factor in falling fossil fuel prices through to 2030 and beyond. Had assumptions of falling wholesale prices been used instead of the 'ever-rising' scenarios, then the question arises as to whether the policy decisions would have been different and the costs of energy correspondingly lower. Lower fossil fuel projections would have:

- increased the importance of switching from coal to gas early on in the decarbonisation process;
- increased the relative costs of renewables in the early period;
- raised the total estimated costs of subsidies to renewables.

20. Lower fossil fuel prices may also have changed the slope of the transition path from the outset to the 2050 target. In section 2 I noted this link to the linear decarbonisation profile in the CCC path to the 2050 target in the CCA.

21. While the private sector has to forecast, and its investment decisions reflect companies' assessment of the net present value of projects, it is important to recognise that this is not necessary for government, except in some specific and difficult cases. In a competitive electricity industry, prices are the *outcomes* of a competitive process, and they are revealed in the wholesale and capacity markets. They are not assumptions. It is the absence of markets that leads to the need to forecast.

A more market-based approach reduces the need for direct intervention, and hence the need for forecasts.

22. The obvious way to reveal prices in a central-buyer context of capacity and FiTs contracts is to auction the requirements for capacity and for the decarbonising investments. In section 7 I recommend a single unified equivalent firm power (EFP) auction. This would generalise the capacity- and technology-specific auctions held so far, and further downgrade the need for BEIS to model the energy system and to conduct economic appraisals on the basis of these assumptions.

23. As was recognised in the early 1980s, the then Department of Energy needed to undertake extensive modelling because the industries were nationalised and planned. There were no competitive markets. At this time the planned systems produced some stunning mistakes, revealing a capacity margin of around 40% in the early 1980s. It was the combination of the *Plan for Coal*, the nuclear programme, and the Central Electricity Generating Board's (CEGB) coal power stations investments which produced so much capacity to make any further investment in the 1980s unnecessary. This did not, however, stop the CEGB forecasting ever-higher fossil fuel prices at the Sizewell and Hinkley Inquiries in the 1980s, and in the latter case to comprehensively ignore the possibility that the alternative to the Hinkley proposal at the time might be gas and not coal.

24. With the abolition of the Department of Energy in 1992, forecasting and detailed modelling ceased since it was no longer relevant. From privatisation in 1990 and the creation of the electricity Pool and capacity mechanisms, investment decisions were passed from the CEGB to the private sector.

25. The exceptional cases where the government explicitly or implicitly may have to make assumptions about fossil fuel prices concern those investments that cannot be subjected to competitive market tendering. These fall into two categories: nuclear; and emerging and immature technologies.

26. In the case of nuclear, the nature of the costs, the time horizons, and the societal decisions about risk and waste make these investments always a matter for the state. Unless there is a market belief that fossil fuel prices will rise very sharply, and the markets are prepared to offer long-term contracts to match such projections, nuclear will not be developed by the competitive markets. The government therefore needs to decide whether and how to proceed.

27. Even where the state decides to proceed, there are a number of ways in which costs can be revealed through auctions and competitive tendering. The nuclear sites can be auctioned, and if the state is directly involved in projects (as it is in most countries), the contracts for the components of nuclear

power stations can be auctioned too. There is then only a residual question as to whether the overall outlook for fossil fuel prices, and the alternative ways of achieving the carbon budgets, merit the investments.

28. In any event, over time horizons which extend to or beyond 30 years, the only way to form a view of the likely fossil fuel prices is qualitatively, not quantitatively. By 2050, the speed of technical change and the decarbonisation policies around the world, following the Paris Agreement, imply that the market for fossil fuels may be in steep decline, and producers will be competing for a diminishing market and diminishing value for their reserves. Indeed, they have to be if decarbonisation is to be achieved. There are good qualitative reasons for assuming that this is a world of falling oil, gas and coal prices. This is not what BEIS assumes, and it is not what the long-run oil supply curve presented in the BEIS 2016 assumptions suggests.

29. This is not just an interesting academic argument. The mindset that goes with ever-higher fossil fuel prices is at odds with a host of technological developments described in section 6, and has led to serious and fundamental mistakes in energy policy, with serious cost implications. These legacy costs will continue to overhang the costs of energy up to 2030 and beyond. Poorly thought-through assumptions tend to justify preconceived policies: they can be examples of *policy-driven evidence*, whereas it should be evidence-based policies. There is a risk that these assumptions could serve to justify decisions which ministers might have been already minded to make.

30. Since the assumptions impact on the policy interventions, they are also a focus for lobbying. There are deep vested interests in the numbers. There is a long track record of using forecasts and assumptions as part of lobbying activities. It is a way in which an apparently 'technical analysis' can lead to capture.

31. There are two possible strategies to cope with this complexity of intervention and the forecasting that supports it. The first is to try to refine and improve each intervention and to forecast better. The second is to reduce the cause of capture – the complexity itself. This requires a fundamental reappraisal, and a focus on the minimum interventions necessary to achieve the two overarching objectives – decarbonisation and security of supply. It is instructive to compare the simple optimal policy instruments – a carbon price and a capacity auction to meet the carbon budgets and the security of supply margin, respectively – with the sheer scale of interventions described above. In sections 11 and 12 I recommend some radical simplifications.

MAIN FINDINGS AND RECOMMENDATIONS

- The detailed mass of interventions is beyond the capacity of officials, regulators and companies to comprehend.
- Complexity encourages lobbying by vested interests in each intervention.
- Piecemeal reforms will almost certainly fail.
- BEIS should consider qualitative analysis of the long-run future of fossil fuels and fossil fuel demands as demand falls with decarbonisation.
- BEIS (and CCC), to the extent that it continues to use assumptions for the residual non-auctioned contracts, should consider a much wider range of scenarios, including a low and falling one for oil, gas and coal prices.
- The government should carry out a comprehensive review of statistical, scenario and forecasting activities in BEIS.

5. The Legacy Costs

This section addresses:

- **the capacity shortfalls as coal closes**
- **the legacy contracts for ROCs, FiTs and low-carbon CfDs**
- **the 'legacy bank' concept**
- **how the legacy costs could be securitised**
- **options for recovering the costs of the legacy assets**

The pre-2000 legacy assets

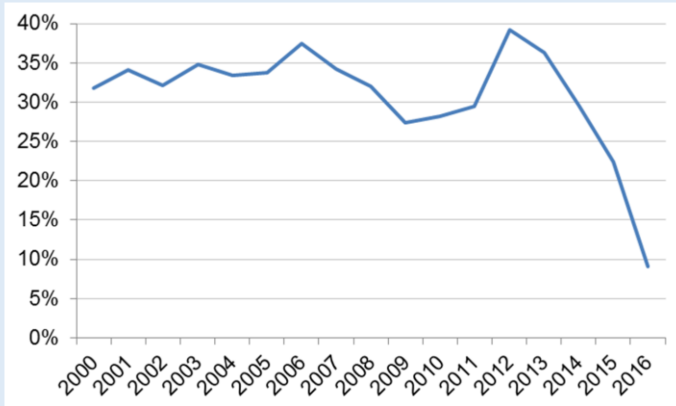
1. Energy systems comprise assets created in the past in the context of the expectations of the time. In the British case, that past is in some cases a long way away. The last coal station built was DRAX in the 1970s, and the nuclear fleet is mostly getting towards the end of its life. Even the first generation of closed-cycle gas turbines (CCGTs) is ageing. The cost of energy is therefore, in significant part, about paying for past investment and operating plant that are suboptimal by today's standards.

2. The inherited power stations have broadly served us well, because until very recently the electricity sector has seen a noticeable absence of much technical progress. The coal power station is 19th-century technology; the combined cycle is part of the turbine advances made during the Second World War; and the PWR (pressurised water reactor) nuclear reactor is 1950s vintage. Most of the transmission and distribution cables have seen only small incremental improvements. Indeed, 19th-century cables that are oil-filled for cooling can still be found in London.

3. The dramatic fall in the share of coal in recent years is illustrated in the box below, followed by a table and bar chart showing the main technologies in the capacity mix going back to 1990.

THE SHARE OF COAL AND THE SHIFT IN THE CAPACITY MIX

FIGURE 19: COAL SHARE OF GENERATION



Source: BEIS (2017), Energy trends.

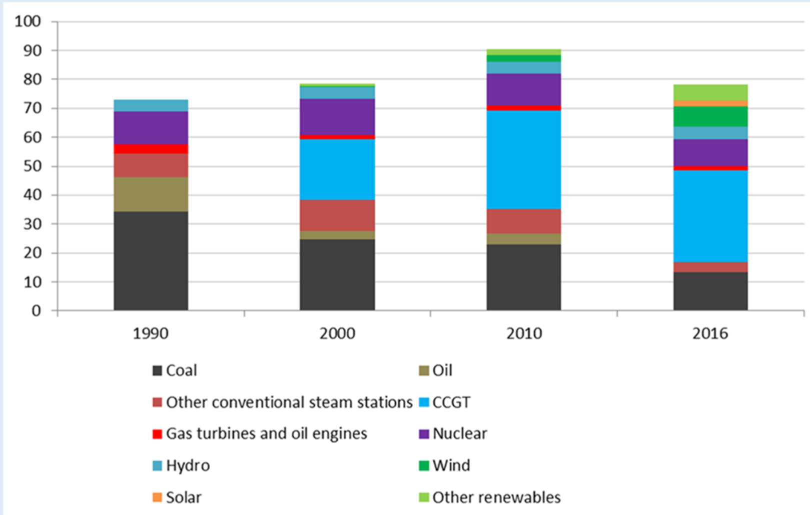
TABLE 4: HISTORICAL PLANT CAPACITY (GW)

	1990	2000	2010	2016
Coal	34.3	24.8	23.1	13.4
Oil	11.9	2.9	3.6	0.0
Other conventional steam stations[1]	8.2	10.6	8.5	3.3
CCGT	0.0	21.1	34.0	31.8
Gas turbines and oil engines	3.1	1.3	1.8	1.4
Nuclear	11.4	12.5	10.9	9.5
Hydro[2]	4.2	4.3	4.3	4.4
Wind[2]	0.0	0.2	2.4	7.0
Solar[2]	0.0	0.0	0.0	2.0
Other renewables[3]	0.0	0.8	1.9	5.5
Total	**73.1**	**78.5**	**90.4**	**78.3**

Source: Digest of UK Energy Statistics, various editions.

Notes: Data before 2006 is based on declared net capacity. [1] Includes gas-fired stations that are not CCGTs, or have some CCGT capability but mainly operate as conventional thermal stations. [2] Small-scale hydro, wind and solar PV capacity is shown on declared net capability basis, and is de-rated to account for intermittency, by factors of 0.365, 0.43 and 0.17 respectively. [3] Includes bioenergy, wave and tidal.

FIGURE 20: HISTORICAL PLANT CAPACITY (GW)



Source: Digest of UK Energy Statistics, various editions.

4. The table below sets out all the coal plants currently operating in the UK. In BEIS's latest projection, all coal plants will have closed by 2025.

TABLE 5: EXISTING COAL PLANTS

Company	Station	Fuel	Installed capacity (MW)	Year of commission or first generation	Location
Drax Power Ltd	Drax – coal units	Coal	1,980	1974	Yorkshire and the Humber
EDF Energy	Cottam	Coal	2,008	1969	East Midlands
EDF Energy	West Burton	Coal	2,012	1967	East Midlands
Eggborough Power Ltd	Eggborough	Coal	1,960	1967	Yorkshire and the Humber
RWE npower plc	Aberthaw B	Coal	1,586	1971	Wales
Scottish & Southern: Thermal	Fiddler's Ferry	Coal/ biomass[1]	1,961	1971	North West
Scottish & Southern: Thermal	Slough	Coal/ biomass/ gas/waste-derived fuel[1]	35	1918	South East
SIMEC	Uskmouth Power	Coal	230	1966	Wales
Uniper UK Limited	Ratcliffe	Coal	2,000	1968	East Midlands

Source: Digest of UK Energy Statistics (July 2017), Table 5.11.

Notes: [1] These plants would not be able to run as coal after 2027. Their support payments will stop, but the decision to close would be their own.

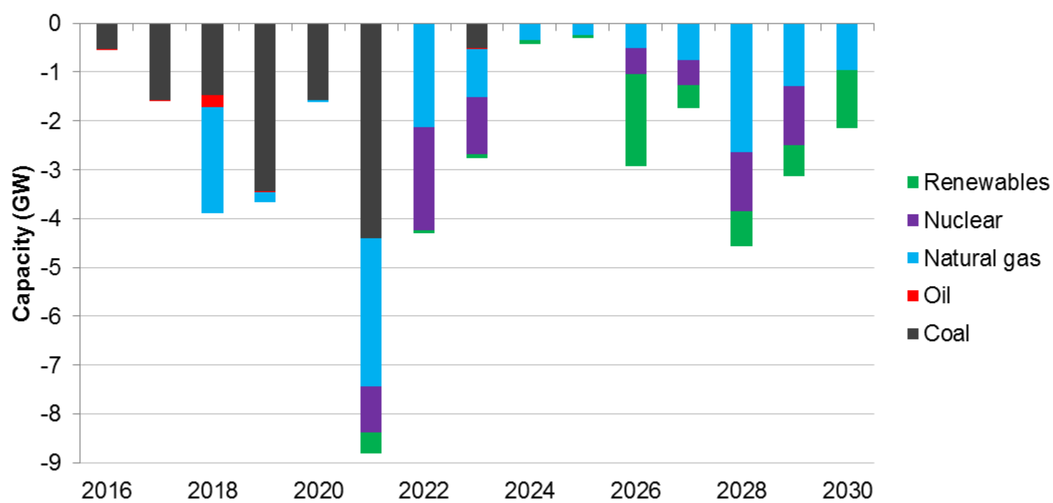
5. Table 6 sets out the nuclear plants which are due to retire by 2035, followed by a chart showing the overall closures through to 2030.

TABLE 6: NUCLEAR PLANTS DUE TO RETIRE BY 2035

Station	Installed capacity (MW)	Year of commission or first generation	Location:	Expected shutdown
Dungeness B	1,050	1983	South East	2028
Hartlepool	1,180	1984	North East	2024
Heysham 1	1,155	1984	North West	2024
Heysham 2	1,230	1988	North West	2030
Hinkley Point B	955	1976	South West	2023
Hunterston B	965	1976	Scotland	2023
Sizewell B	1,198	1995	East	2035
Torness	1,185	1988	Scotland	2030

Source: Digest of UK Energy Statistics (July 2017), Table 5.11; World Nuclear Association website: http://www.world-nuclear.org/information-library/country-profiles/countries-t-z/united-kingdom.aspx; https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/604271/Nuclear_Capacity_in_the_UK.pdf.

FIGURE 21: PROJECTED CAPACITY CLOSURES, 2016–30



Source: BEIS (2017), Energy and emissions projections 2016.

6. It is only recently that the energy mix has been open to technical change. It was illegal in Europe (and the US) to burn gas in power stations until 1990, for fear that a precious fuel might be depleted too quickly instead of being reserved for the higher-value petrochemicals industry.

7. With the exception of the ageing nuclear power stations, and before the coming of the capacity contracts, these older assets do not come with legacy costs that impact on the costs of energy going

forward. They are legacy assets but not legacy costs. Most of those assets built by the CEGB were paid for on a pay-as-you-go basis, and have been depreciated. They have been paid for by consumers already. Their current value is determined by the expected revenues which come from the wholesale market and any new capacity contracts they can attract, minus the costs of carbon and complying with other emissions regulations. This balance determines whether the stations should be closed.

8. The coming of capacity contracts adds a new dimension to the cost of energy from these older stations going forward. As the capacity market has tightened, and as more intermittent renewables have come onto the system, some of these stations have been offered limited fixed-price contracts over a forward period to have their capacity available. There is then a forward cost over and above the returns from the wholesale market. In a further twist, as the wholesale price has fallen, for reasons which will be explained in section 7, the closure decisions have in some cases been brought forward (and reinforced by the CPF and environmental regulation). Finally, there are a number of balancing and ancillary services these old stations may be able to provide and get paid for.

The post-2000 renewables and their legacy costs

9. Since 2000, the pace of change has accelerated with the coming of renewables which have been grafted onto a system designed with ever-larger baseload power stations in mind. So far, these have added quite a lot of capacity, but less energy.

10. The UK embarked on a dash to meet the EU Renewables Directive target, which was one for energy rather than electricity.

11. The EU has adopted a definition of renewables which excludes low-carbon nuclear, but includes biomass. Indeed, biomass makes up a significant proportion of all the renewables in the EU in meeting the Renewables Directive. Large-scale biomass can lead to significantly higher-carbon pollution than nuclear.

12. The EU proposes a new EU-wide renewables target from 2020 to 2030, backed up by national plans scrutinised by the Commission to determine whether they are consistent with the overall EU target.

13. A post-Brexit UK can avoid these additional technology constraints, and there is in any event scope to come up with a better definition of renewables and what qualifies for FiT and low-carbon CfD support. Given that the target in the CCA is in carbon, it should be a low-carbon generation measure and not an arbitrary renewables one. As the costs of renewables fall, the special treatment can

wither away over the next decade. I set out proposals on how to do this, and how to manage the transition in Part III.

14. There have been a series of mechanisms for subsidies beginning with the ROCs, then the FiTs and the CfDs. In section 7 I set out the various support mechanisms.

15. The current renewables have significant legacy costs, which will contribute to electricity bills going forward. They should be clearly separated from the costs of future renewables, which are likely to be much lower. If the full avoided carbon costs are factored in, and with new battery storage and demand-side technologies and options, they should be able to compete with the conventional fossil fuels, once they too pay their full carbon costs. The cost of capital will also be important, especially in respect of some of the securitisation options I advance in section 7.

16. Calculating the legacy costs of all the renewables contracts already signed for the coming years depends on a number of underlying assumptions, and in particular the expected wholesale costs, and in turn the underlying assumptions about gas prices. It also requires that the carbon price is factored in. There is no obvious 'right answer', because there are no obvious 'right assumptions'. But the exact calculation, and the particular assumptions, are less important that getting the broad numbers for the legacy roughly right. I recommend that the government should carry out a series of calculations based on a range of assumptions.

17. The Levy Control Framework (LCF) was designed to control the costs of supporting low-carbon electricity, paid for through consumers' energy bills. It sets an annual budget for projected costs of all BEIS's low carbon electricity levy-funded schemes until 2020/21, rising to £7.6 billion in 2020/21 (2011/12 prices).

18. The LCF includes the costs of the CfDs, the RO, and the FiTs, as well as early CfDs awarded under the Final Investment Decision enabling for Renewables (FIDeR) process.

19. The CCC has produced estimates of the LCF cost to 2030. They are estimates of support payments only, and ignore intermittency, merit order effects, and other costs. It is in the nature of systems that costs cannot be assigned on a marginal basis: that is what follows from having an integrated system. These extra legacy costs are therefore open to debate.

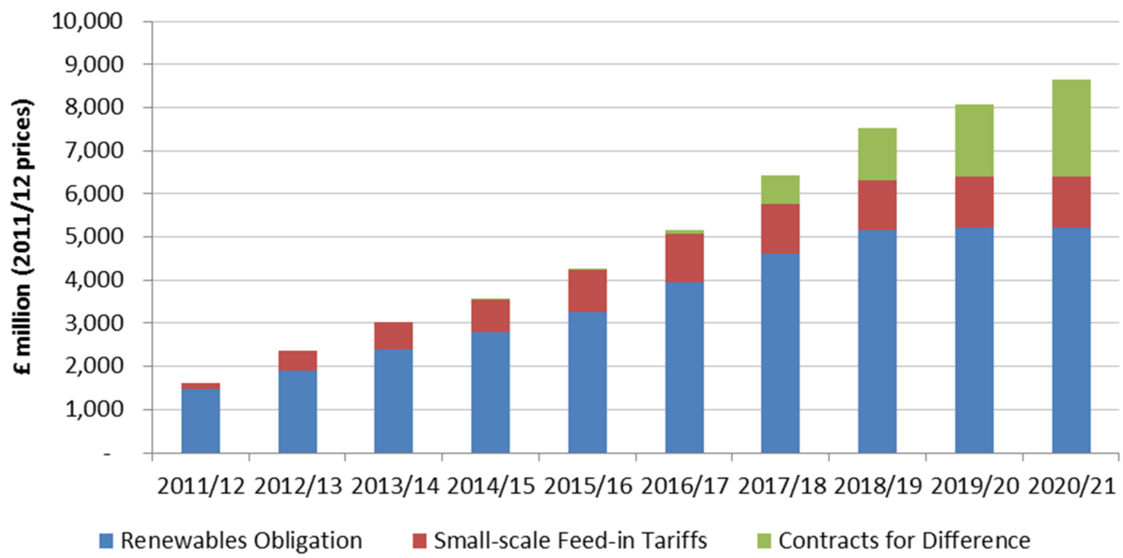
20. The table below sets out the CCC numbers, followed by a chart of how the LCF grows over the period.

TABLE 7: THE CCC'S ESTIMATES OF LCF COSTS

£ million	2016	2020	2030
Committed renewables to 2020	**5,511**	**8,832**	**7,298**
Small-scale FiTs (eg, rooftop solar)	1,123	1,207	1,207
Renewables Obligation	4,017	5,395	4,483
First CfD auction round	1	511	301
FIDeR CfD projects	370	1,719	1,307
Announced low-carbon projects beyond 2020			**1282**
September 2017 offshore wind auctions			307
Further funding announced for offshore wind			465
Hinkley Point C			510
Additional low-carbon generation in CCC's Fifth Carbon Budget scenarios			**864**
Offshore wind			317
CCS			797
Hinkley			0
Mature renewables (onshore, solar)			–559
Marine			310
Low Carbon Contracts Company (LCCC) administration costs		17	17
Total LCF costs	**5511**	**8849**	**9461**
% of total that is already committed	100%	100%	91%
% of total that is required for Fifth Carbon Budget	0%	0%	9%

Source: CCC.

FIGURE 22: LEVY CONTROL FRAMEWORK AND PROJECTIONS



Source: BEIS (2016), 'Consumer-funded Policies Report', https://www.gov.uk/government/publications/consumer-funded-policies-report; Office of Budget Responsibility (2017), 'Economic and Fiscal Outlook – March 2017', available at http://budgetresponsibility.org.uk/efo/economic-fiscal-outlook-march-2017/.

Notes: Spend up to and including 2015/16 is actual data as published by BEIS (2016); spend from 2016/17 is projected as published the Office of Budget Responsibility (2017) and converted to real 2011/12 prices using RPI and CPI forecasts published by the Office of Budget Responsibility in March 2017; 'Contracts for Difference' is the sum of CfDs, investment contracts, and LCCC operating costs.

21. The LCF costs qualify for the legacy cost category, but they may need adjustment to take into account the appropriate cost of carbon and other assumptions which I have recommended should form part of the government's analysis.

22. There are three main points which emerge from the CCC calculations and the forward-looking chart. First, the sheer scale of the numbers gives an indication of how expensive the ROCs and EMR contracts have been so far. It is hard to imagine that more carbon reductions could not have been achieved for a total cost which will exceed £100 billion by 2030 – or that the same could not have been achieved for significantly less. Second, the numbers are around 90% already determined. Falling costs for future renewables will not result in lower legacy costs. Third, the falling costs of intermittency will not feed through to a lower LCF because these costs are excluded.

23. It would be wrong, however, to assume that all the LCF costs could have been avoided. The glaring omission in this calculation is the cost of carbon. From the broader economic perspective, the renewables and nuclear are part of the ways in which the carbon budgets are being met. If the

carbon price that would be necessary to meet the carbon budgets is deducted from the LCF, the measure would be a better estimate.

24. Whatever the 'right' answer, the key fact is that these LCF costs are sunk. There is no escape, and this is why they should be treated as legacy costs and taken out of the market. Sunk costs should not impact on future behaviour – even if they have to be paid for. The challenge is to isolate them out so as to limit the impacts on future behaviours to ensure that the money raised to pay for them is as least-distorting as possible, and to minimise them.

25. The legacy costs can be grouped into a 'legacy bank'. This would contain the liabilities that customers and industry face from past ROCs, FiTs and CfD contracts that are out of the market, however calculated, and the liabilities for future contracts that are out of the market, for as long as the FiTs and low-carbon CfDs persist. There is a parallel with the out-of-the-market loans included in 'bad banks' after the financial crisis.

26. These legacy costs cannot be avoided: they are legal contracts that are backed by the government. Part II sets out how these costs might be reduced by more efficient approaches to financing, as well as some of the opportunities to renegotiate them.

27. The merit of their separate identification is that they can be taken out of the market, leaving the future market to reflect the expected falling prices for renewables, for batteries and storage, for the demand side, and decentralised electricity systems. They would represent a transparent charge, and be open to government to choose between the alternative bases – between household and industrial customers and other options. As set out in section 10, there is a good case for exemption of industry from these legacy costs. This would have the merit of regularising the many and varied exemptions, and put industry on a common footing, and a common harmonised carbon price which I recommend in section 10.

MAIN FINDINGS AND RECOMMENDATIONS

- The government should adopt a low-carbon definition to replace the narrow EU renewables definition as a temporary measure for the renewables transition towards subsidy-free status.
- Legacy contracts should be grouped into a legacy bank. The bank should include all the outstanding ROCs, FiTs and low-carbon CfD contracts. These should be ring-fenced and separated, distinguishing between the competitive price of electricity going forward and what is in effect a tax on customers.
- Government should consider how it wants to allocate legacy costs between customers. This should be explicit and transparent in customer bills.
- It is likely that further nuclear projects will add to the legacy bank liabilities, as will Hinkley beyond 2030.

6. Technical Change

This section addresses:
- **the potential of the technical changes coming**
- **the impacts of the digitalisation of the whole economy and what this means for electricity**
- **the next generation of renewables**
- **the electric transport opportunities and impacts**
- **the inherent uncertainty and how policy and regulation should take it into account**
- **the role of R&D, innovation, and industrial strategy and policies**

1. Technical change not only reduces costs and creates new products and services, but also changes the cost structure of the energy industries. While many focus on trying to predict how the technologies will evolve, the main concern for the cost of energy is how the generic characteristics of the coming technologies change underlying cost structures and therefore the structure of the industry.

Why the current structures emerged and why they are increasingly badly designed

2. As noted in section 5, the UK's electricity industry is the product of a series of technological developments that emerged at the end of the 19th century, augmented by nuclear and gas turbines in the mid- and late-20th century, respectively.

3. This has been the case until very recently. Coal once accounted for almost all electricity generation globally, and with the coming of nuclear the ratio moved to roughly 80–20 coal–nuclear in many developed countries. The national transmission system was added and power stations got bigger, but cabling advances were glacial. Throughout its history, the electricity industry has been moving from the local to the national, and now gradually international.

4. Throughout its history, there have been three key problems for the electricity industry: electricity could not be stored, except at the margin; the demand side was passive; and the marginal costs determined the wholesale price as the main economic driver of the industry. These three features, plus the sunk costs of large-scale power stations, gave us the structure of the industry which dominated the 20th century: large, vertically integrated companies, with either statutory monopolies or significant market power. This is the economic model that produced RWE in Germany, EDF in France, and the CEGB in Britain.

5. Energy policy and regulation have followed this cost structure. The security of supply objective dominated, with centrally determined capacity margins, backed up by planning for coal mining and other fuel supplies, and state-owned nuclear industries. At the consumer end, there was a gradual roll-out of connections to the electricity networks, analogous to the challenges today of the roll-out of high-speed broadband. Cross-subsidies were endemic, particularly to peripheral and marginal customers, and the statutory monopoly facilitated and maintained these. The USO was grounded in these monopolies.

6. The coal-based electricity systems followed a merit order in centrally scheduling generating units. The key to this was the wholesale marginal costs. Dispatch followed SRMC, and the price was determined by the SRMC of the last unit dispatched, defined as the system marginal price (SMP).

7. In the 21st century all of these three main assumptions are being undermined by technological progress. In particular, a future electricity system is likely to be:
   - storable, not non-storable;
   - active, not passive, on the demand side;
   - increasingly zero marginal cost, and not a rising marginal cost–supply curve.

8. Any one of these changes would have profound implications for the industry structures, energy policy and regulation. Together they will gradually render almost all of the existing arrangements redundant. Indeed, the longer the existing frameworks stay in place, the greater the risk that they will be obstacles for change, and hence raise costs. The long-run framework set out in section 11 is based on these new assumptions.

The generic technological seismic shifts

9. Behind these shifts lie three broad technological advances: digitalisation and smart demand; renewables energy generation technologies; and batteries and storage technologies. The combination of the three is what will shape our energy future, although determining precisely how would require predictions, and neither energy policy nor regulation should try to make these sorts of predictions. The long-run framework should be open to a wide range of surprises, only some of which are predictable.

(i) Digitalisation

10. Digitalisation is a general-purpose technology – the extension of the computer and IT revolution that started in the 1980s. The generic observations that can be made are:

- almost everything can be digitalised;
- digitalisation will be powered by electricity;
- digitalisation facilitates robots, 3D printing and AI;
- digitalisation facilitates autonomous cars;
- digitalised smart grids, smart meters, and smart cities enhance coordination and an active demand side with the emergence of new energy services;
- households and buildings will be opened up to active demand management;
- data becomes a key and valuable economic commodity;
- digitalisation will change the nature, location and organisation of manufacturing and services;
- digitalisation opens up the new threat of cyber-attack and system failure challenges to the security of supply.

11. For the electricity industry, digitalisation creates new and larger domestic and especially industrial markets. Electricity will be the final energy form of choice – at the expense of oil, gas and coal. It is a key route to decarbonisation. It changes the nature and demand for security and security of supply. Finally, it creates a whole new industry in the provision of energy services, based on big data, and therefore opens up a large number of new energy efficiency opportunities.

12. Digitalisation enables the demand side of the market to be active, not passive. This changes the ways in which the security of supply is handled, and opens up a cornucopia of opportunities for appliances, the management of vehicle charging, and the balancing of local and national energy systems. Demand becomes an equal partner with supply. Systems can be smartly managed, especially at points of stress. The opportunities that an active demand side brings will dampen volatility in the wholesale market by adding further flexibility and balancing opportunities and, in the process, reducing the impacts and costs of intermittency.

13. This activation of the demand side is reinforced by the changes from digitalisation to the networks themselves and the opportunities for system operation. Later I recommend the establishment of RSOs as well as the NSO to help exploit these opportunities. These are a new way of meeting the overall objectives and enhancing competition. Digitalisation makes these both possible and necessary.

14. Digitalisation holds out promise to aid the management of heat demand, and the electrification of heat. Unlike electricity demand, heat does not have to be provided instantaneously, and hence the management of hot water and other heating systems can be fine-tuned by digitalisation of

appliances and smart energy systems. It can be partly met through non-firm power. Although heat is largely outside of the scope of this review, its integration with demand management, storage and energy services offers considerable scope to reduce the carbon emissions associated with it.

15. Consumer experience of digitalisation comes through the new energy services that will be offered, supported by broadband hubs, apps and smart meters, and their ability to gain greater energy efficiency.

16. The old model of a passive demand side is giving way to active demand-side management. This is not only about energy consumption directly, but about enabling houses and buildings to become their own energy systems. As a result, it will help to crack this major source of carbon emissions, as identified in section 2, and work alongside the energy efficiency programme further enhanced in the *Clean Growth Strategy*.

17. It is hard to manage electricity demand if it cannot be measured accurately and in real time. The government's policy is to mandate the offering of smart meters to every home by 2020 – in effect a new part of the USO.

18. Smart meters should perform a number of services:
    - providing real-time data on consumption;
    - enabling the household to see and actively respond to its consumption;
    - providing information to the system for better management of system demands, and hence the management of supply to meet demand;
    - enabling customers to switch supplier more easily.

19. Like any big infrastructure project, the smart meters programme has encountered problems. An early decision – and a mistake with profound consequences – was to place the meters in the supply, and not the distribution licensed activities of the distribution network operator (DNO) companies, unlike almost every other European country. This will have increased the costs of capital and some of the costs of deployment in defined locations. The government at the time argued that these costs would be outweighed by the innovation which suppliers were thought to bring, and especially through their direct customer relationships.

20. The distribution businesses would have had, like in other countries, the opportunity to drive replacement of existing meters as part of their functions, and the result would have been a more coordinated and comprehensive programme. This would have been analogous to the gas network

developments with the coming of North Sea natural gas. The meters could have gone into the RAB at a much lower cost of capital. Instead, the supply approach meant that it would be voluntary and supplier-led. The result is that the roll-out is haphazard, patchy and high-cost – ironically, with the costs being passed through to customers as they would have been in the distribution RAB case, but at higher levels.

21. The incumbent suppliers have the incentive to capture and keep customers. Switching is not in their interests, but the CMA argued that smart meters would increase switching. In the first phase of deployment, some of the meters have not been able to facilitate switching on a smart basis from one supplier to another. This is what would be expected given the incentives.

22. Digitalisation is moving on fast, with the major new developments focusing on apps and the suite of broadband connections that control appliances directly, and with the development of new types of boilers for heating and the electrification of heating referred to above.

23. A key issue is whether households really want to actively engage in making conscious choices about consumption, or whether they want these services managed for them. It may be possible for an energy services provider to automatically manage appliances and boilers, and to switch automatically to the lowest tariffs available suited to the specific needs of the household.

24. There are a number of ways of dealing with the emerging issues in the roll-out of smart meters. Two of my related recommendations set out in sections 8 and 11 are that the licence barriers between supply and distribution (and generation) should be removed, and that the decentralised regional systems should be coordinated by new RSOs, separate from the DNOs. A third recommendation in section 9 relates to the default tariff structures I propose, and the intensification of competition focused on transparent supply margins.

25. Estimating the benefits from the smart meter programme, and whether the programme the government has set in place is cost-effective, depends on a complex range of assumptions, including in relation to future fossil fuel prices. If the prices are assumed to rise, the avoided cost is obviously greater. It depends too on the energy services offerings, energy efficiency gains and, crucially, whether and to what extent consumers and industry take up these new opportunities. It also depends on whether the benefits could accrue by other means – for example, directly through broadband hubs, apps and other interfaces with customers.

26. In promoting smart meters, BEIS has made some bold claims about their benefits. These are set out in the box below.

SMART METERS: GOVERNMENT CLAIMS ABOUT THE OPPORTUNITIES AND EVIDENCE

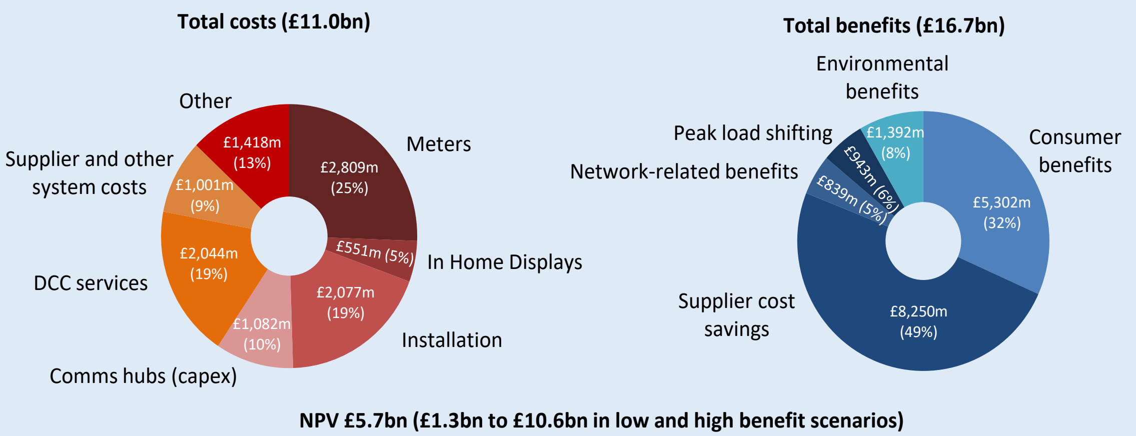
Smart meters will provide automatic, accurate energy bills, immediate feedback on energy consumption, and the foundation for a smart energy system.

They are projected to reduce energy bills by £11 in 2020 for the average dual-fuel household, rising to £47 by 2030, and £128 for the average dual-fuel non-domestic bill, rising to £147 by 2030. These bill savings are a combination of the pass-through of net industry cost savings and reduced energy consumption.

While upfront investment has been required to install smart meters in every home and small business, and establish the national smart meter data and communications system, over time these are outweighed by significant benefits from industry and network cost savings, consumers using less energy, reduced bills and a decrease in GHG emissions.

Smart metering is expected to deliver net present benefits of £5.7 billion (discounted benefits of £16.7 billion above discounted costs of £11.0 billion) in the period to 2030.[1]

FIGURE 23: EXPECTED BENEFITS OF SMART METERING



Source: BEIS (2016), 'Smart Meter Rollout Cost Benefit Analysis: Part I', https://www.gov.uk/government/publications/smart-meter-roll-out-gb-cost-benefit-analysis.

Notes: [1] Central projections, present value 2016 base year, 2011 prices. NPV, net present value.

SMART ENERGY: OVERALL CASE

Flexible technologies, including DSR and storage facilitated through smart meters, could save the system £17–£40 billion by 2050.

The National Infrastructure Commission's central finding is that smart power – principally built around three innovations: interconnection, storage, and demand flexibility – could save consumers up to £8 billion a year by 2030, help the UK meet its 2050 carbon targets, and secure the UK's energy supply for generations.

Source: National Infrastructure Commission (2016), 'Smart Power: A National Infrastructure Commission Report'.

Source: BEIS.

(ii) Renewables electricity generation

27. The second broad generic shift comes from the new renewables technologies, and specifically from solar and wind. These are the first-generation technologies to begin to make inroads into the generation of electricity.

28. These first-generation renewables would not have prospered but for the decarbonisation objective, the EU Renewables Directive, and the subsidies to promote them. The existing fossil fuel technologies are highly unlikely to be rendered low- or even zero-carbon. Carbon capture and storage (CCS) might help, and it is being further supported in the *Clean Growth Strategy*. It is unlikely to do so at scale for several decades. The other alternative – nuclear – shows no global signs of coming to the climate change rescue at a scale necessary to displace coal- and gas-fired generation in the near future, although Hinkley and the potential nuclear projects in the UK could amount to around 13GW by the early 2030s, and therefore could at least replace the closing existing nuclear capacity.

29. There is now a major drive to develop and innovate renewables, together with more fundamental R&D. Whatever the merits of the specific subsidies and supports, and the scale of the legacy costs they have left, renewables costs are likely to keep on falling for the existing vintage of technologies. Adjusted positively for the cost of carbon, and internalising the externalities and taking account of the falling costs of dealing with intermittency and the additional network costs, many claim that the current vintage of renewables will be subsidy-free in the next decade. Some have argued that this could come sooner – by 2020 – when customers would be better off in comparison with the assumed high and volatile gas prices. The 2020 prediction turns out to be wrong, and gas prices have fallen sharply, pushing out the date for subsidy-free renewables. But as the costs keep falling, it is widely argued that it is only a matter of time.

30. The future energy policy regime and regulation can therefore look forward to the phasing-out of FiTs and low-carbon CfDs. In section 11 I set out how this transition can be managed, and the role of renewables in the long-run framework as they are normalised into the electricity systems at the national and local level, through the NSO and RSOs.

31. R&D brings the promise of new and much more efficient renewable-generation vintages. The most exciting of these probably lie with solar (although there will be surprises and other options should be included). There is much science to develop – particularly in capturing more, and more efficiently, parts of the light spectrum – and a host of new materials and technologies for converting

the captured solar energy into electricity and distributing it. This, in turn, holds out hope not just for low-carbon electricity but the greater management of heat too.

32. Technological advances in wind generation are unfolding, although the scope is limited by the specific nature of wind turbines. The blade design, the steel in the supporting structures, and the efficiency of the conversion to electricity are all areas for incremental improvements. Given that wind is a small-scale and low-density form of generating electricity, many of the cost reductions have come from the logistics and maintenance, especially offshore, and new designs of floating platforms add a further opportunity. Although incremental, the cost reductions have been dramatic, and as with solar, the subsidy-free future is getting nearer, especially for onshore facilities. FiTs for wind can therefore be gradually phased out.

33. The R&D and innovation dimensions will continue to require public support. The conventional argument is that this is best delivered by technologically specific FiTs and CfDs, so that there can be large-scale deployment. There are undoubtedly cost reductions which follow from large-scale deployment, but there are at least four caveats. First, these are global technologies and hence any deployment almost anywhere can have these impacts. The question is whether there are unique dimensions relevant to the UK. Offshore wind and CCS in the North Sea are probably the only candidates. Second, the gains come in the design and development of the equipment itself, and in the manufacturing processes. Large-scale Chinese manufacture of solar panels, and of wind turbines, is a major contributor. Third, it is far from obvious that a FiT or CfD is the right kind of contract to facilitate the R&D and innovation. In section 7 I recommend a split-contract approach for the interim period as the FiTs and CfDs are phased out, and after existing auctioning commitments have been met. Finally, there is a powerful case for direct R&D policies and for policies to focus on the capital costs of the project developments.

34. The new renewables technologies transform and undermine the assumptions of the 20th-century electricity industry for a further reason: they are zero marginal cost, with the exception of biomass.

35. Zero marginal costs have already begun transforming the electricity industry. They undermine a core feature of the 20th-century industry: the overwhelming dominance of the wholesale market, in turn driven by the price of coal and gas. In a purely zero marginal cost world, there is only capacity. The energy itself is free.

36. It is hard to underestimate the scale of the revolution this entails. This is the economics of broadband, not electricity as we know it. Energy efficiency is about reducing the need for more

renewables *capacity*, not the use of energy itself from given capacity. The economics of energy efficiency is related to the price of marginal new bits of capacity being brought onto the system. As long as this is a rising supply curve, demand is rationed off by price, and energy service companies operate on that margin. But now suppose the cost of each new and extra unit of capacity is lower, and the supply curve is downward-sloping. The problem becomes one more like the copper wires problem in broadband, or the last vintage of iPhones. The incumbents will seek to protect their older vintage technologies from technical change.

37. The FiTs and low-carbon CfDs are one such protection. In the case of the first nuclear CfD, this protects the current nuclear technology for 35 years after it starts to generate electricity from the possibility of new and lower-cost, low-carbon generation. The nuclear plant will always run, reducing the market available to newer technologies until mid-century or possibly longer. This could act as a brake on technical change. The effect might be small, but should be taken into account. As noted in section 7, there are a large number of factors to be taken into account in designing nuclear contracts. This review does not reach any conclusions on the specifics of the Hinkley project, being outside its Terms of Reference.

38. In a zero marginal cost world, it is all about capacity, and I later recommend that the market design should shift to reflect this. It is mainly for this reason that I am less concerned about market power in the wholesale market, since the market itself will be gradually undermined, and why I recommend the merger of the FiTs and low-carbon CfDs into the capacity auctions as a single EFP market. The role of the wholesale market declines in importance, and its role is increasingly concentrated in the sale of non-firm power and as a mechanism to address the intermittency of renewables. These issues are all discussed in section 7.

(iii) Batteries and storage

39. The third major vector of technological change is in storage, reversing the 'no storage' assumption that underpins the current industry structures. New storage technologies reduce the problem of meeting peaks in demand, and dampen wholesale price volatility, back up solar and wind intermittency, and open up the prospect of the electrification of transport.

40. Batteries have a long history. Indeed, vehicles have needed batteries for much of their existence. What has changed the battery technologies has been the coming on the lithium ion battery (patented in the 1980s) and the enormous economic incentives to R&D and innovation that have

come from the new markets for laptops, tablets and mobile phones, none of which would have been possible without their tiny batteries. The batteries remain a serious challenge to those technologies which need repeated recharging.

41. A new and further push for R&D comes from the electrification of transport (see below) and from the need to tackle the intermittency of renewables, especially at the decentralised level.

42. So far, technical progress in batteries has been incremental, and because the IT industry has concentrated on lithium ion, it has concentrated on this specific technology. Other battery technologies may eventually overtake lithium ion. The future demand for batteries will grow, and as it does, the costs will come down, and with them the growth of not only storage at the macro level, but also batteries at the network level, will come into play. It is implausible to try to predict how fast these costs will fall, and by how much. The important point is to ensure that market design, regulation and policy go with the grain of battery developments and facilitate their wider applications.

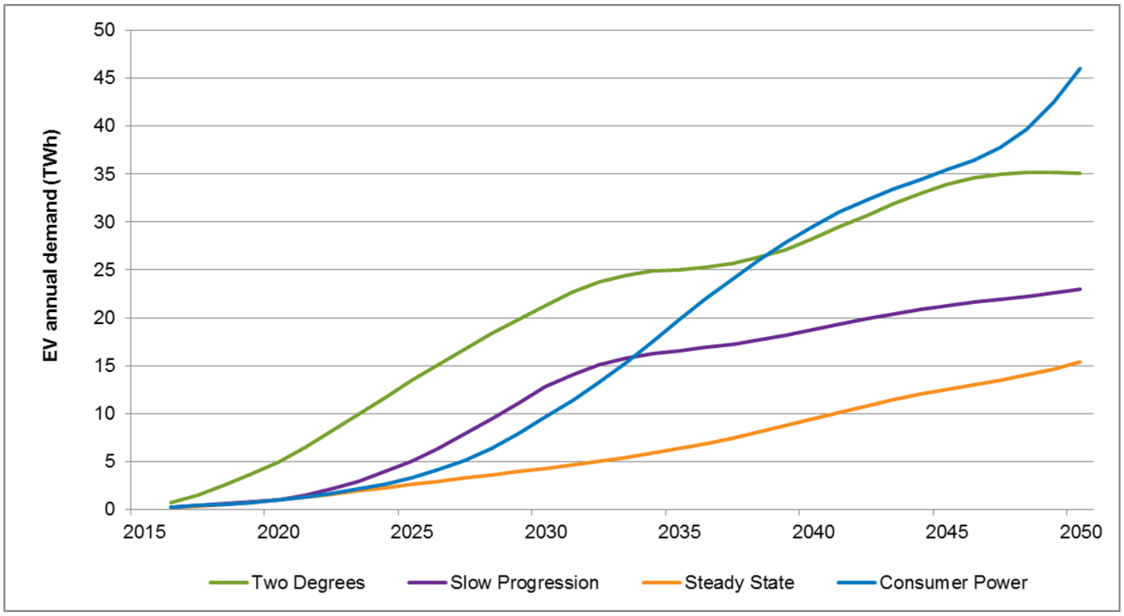
43. Batteries are not the only form of storage, and there are rapid developments across a spectrum, which has to date typically been confined largely to hydro and to pump storage.

The coming of electric transport

44. To these three fundamental shifts, the accelerating deployment of EVs adds a new dimension. Although they were developed in the late-19th century as a potential rival to the internal combustion engine, modern EVs are themselves part of the digitalisation revolution. They are dependent on batteries, and they need to be charged from low-carbon sources in order to meet the decarbonisation objective. The coming of EVs is therefore part of meeting the decarbonisation objective. It also impacts on security of supply, in the form of security of charging.

45. A number of projections of the impact of EVs on peak demand – and hence capacity – have been made, notably by National Grid. These are set out in the chart below.

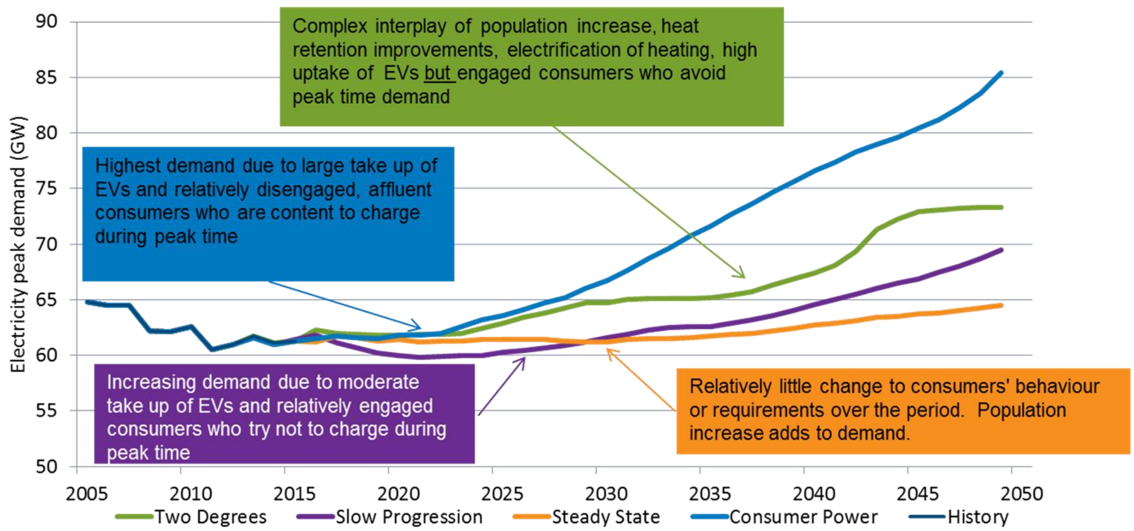
FIGURE 24: EV DEMAND FOR ELECTRICITY (TWHRS)



Source: National Grid (2017), 'Future Energy Scenarios', July, available at http://fes.nationalgrid.com/fes-document/fes-2017/.

46. Projections for peak demand should be treated with caution. EV drivers do not necessarily demand instant charging. What they need is battery power on demand. This tends not to happen during several hours of the night, so the window for recharging may be longer than the actual charging times, and recharging could be done at times of lower demand on the electricity system. Digital technologies and smart meters and networks, plus innovative pricing for peaks, may significantly further ameliorate the problem.

FIGURE 25: ELECTRICITY PEAK DEMAND



Source: Figure 3.2 of National Grid (2017), 'Future Energy Scenarios', July, available at http://fes.nationalgrid.com/media/1253/final-fes-2017-updated-interactive-pdf-44-amended.pdf.

47. Electric transport requires an infrastructure of charging points. It is a classic infant infrastructure problem: the network is economic only when there are lots of EVs charging from it; and the EVs are worth buying only if the infrastructure is in place. It is therefore a textbook example of the need for government coordination – a problem currently shared with high-speed broadband roll-out (the fibre is not worth providing universally unless broadband services are universally used; and the use of broadband services depends on the fibre being in place).

48. The government has set a target date, 2040, for the ending of the sale of diesel and petrol cars (excluding hybrids). If credible, this provides a baseline for car manufacturers and networks to plan the development of the cars and the charging systems. In both cases they are likely to be smart – a benefit of digitalisation. Coordination reduces the cost of energy, and it works if – and only if – the target is itself credible.

49. The electric networks have a crucial role in all this. They have to ensure that there is the infrastructure in place, and this in turn includes involvement in the planning of the locations for charging. Petrol and diesel cars have entirely separate refuelling networks from electricity, tied to the roads system. It is an open question as to whether conventional filling stations are the ideal location for charging given the nature of the existing electricity distribution systems. They could become energy islands, generating electricity and charging batteries on-site, with limited back-up. One option is for drivers to swap batteries at garages, and for these to then be charged at times of

low demand on the electricity system. China is exploring this option. This would require considerable coordination and standardisation of batteries across car manufacturers. New charging stations could be based around key nodes in electricity distribution systems.

50. Drivers may choose to charge their EVs at home overnight or at work-place car parks. As long as charging takes time, and as long as there are cheaper sources of supply when demand is lower for other purposes – and provided that storage of wind and solar energy in particular develops – a very local solution has attractions.

51. In many infant infrastructures, it takes time for the costs of the alternatives to be fully understood, and the initial phase is a free-for-all. This was the case for canals and railways, and for mobiles and early broadband. However, there are two reasons why a 'wait and see what happens' approach is unlikely to work well for EV charging. First, the timescale is compressed because of decarbonisation. Unless transport decarbonises (alongside agriculture, buildings and electricity), the overarching CCA objective is in jeopardy. There simply may not be enough time for the various experiments to play out. Second, the coming of EVs has profound impacts on the existing electricity system.

52. For these reasons, the networks and the car industry need to coordinate the roll-out and the location and investments in charging facilities. I recommend that the regulatory regime takes this into account, and the *Industrial Strategy* explicitly sets out a framework.

The sheer scale of the uncertainties and the implications for policy and regulation

53. The above technological developments are largely generic. There will be more digitalisation of the economy; there will be more smart systems; there will be advances in renewables technologies; batteries and storage will progress; and EVs are coming. These are predictable surprises.

54. It is tempting for governments and regulators to go beyond the generic and start predicting the future winners and creating scenarios. This is something companies do in their day-to-day business when they are planning investments. It is something governments should avoid. Their track record is typically bad, and sometimes very bad, and they are always vulnerable to capture by vested interests trying to sell their technologies to government and capture subsidies and economic rents. This is why identifying generic changes in technology is wholly different from picking winners.

55. The role of government is to design infrastructure and industrial strategies to follow these generic paths. In the case of energy, government needs policies that go with the grain of digitalisation, and especially the use and regulation of data, as well as R&D and innovation policies to help bring

forward the science of solar in particular. It also needs an infrastructure policy to facilitate the two key network developments: smart decentralisation; and electric charging systems. In section 8 I recommend the creation of RSOs as the principal vehicles for developing decentralised networks and regulating them, and the gradual abandonment of the regulatory periodic reviews in the face of rapid technological change. Trying to set regulatory periodic assumptions over eight years (and ten if the build-up time is included) is hopeless in the context of such rapid and uncertain technical advances.

56. To these can be added the need to develop a roll-out plan for the EV charging network, and here the National Infrastructure Commission (NIC) long-term infrastructure plan may be a useful starting point, which will then need to be implemented through the NSO and the RSOs that I recommend.

R&D and innovation policies

57. There is a long history of R&D and innovation policies, and a substantial body of literature on the design and empirical evidence on what does and does not work. It is neither the purpose nor the intent of this review to recommend a detailed set of policies in this area. Instead I confine my recommendations to a number of core principles and the institutional structures.

58. R&D is a generic problem. Breakthroughs come through a combination of methodical team-based processes, brilliant individuals, and through new connections and ideas, often as by-products of other research. Sometimes big programmes have these spin-offs. Reaching the moon, designing new fighter planes, and now cyber warfare and drones are all areas where there have been big and unintended spin-offs. There are two lessons from this: first, because the outputs of R&D cannot be known (otherwise there would be no need for R&D), it is a mistake to focus exclusively on specific research; second, broad-based research policies and institutions are better than narrow ones.

59. In the energy sector, there are nevertheless a number of well-defined research problems, and many less well defined. Tasks like improving the take from the light spectrum or finding new materials and applications, such as that ushered in by graphene, fall into this defined category, as do battery research, plant sciences and new biomass opportunities, and so on. This is why there are research centres and research programmes. There is much benefit from competition between universities for funds and in solving problems.

60. Research is not, however, a narrow competitive process, and the missing link in the energy sector is an overarching coordination of research and a national energy research laboratory. The box below sets out the plethora of centres and institutions that are already crowding the research landscape.

The R&D landscape

Research councils

Biotechnology and Biological Sciences Research Council	One of seven research councils that work together as Research Councils UK. Its vision is for the power of biology to deliver a prosperous and sustainable future. To deliver this vision, BBSRC invests in world-class bioscience that builds capability and realises benefits for the economy and society.
Engineering and Physical Sciences Research Council	EPSRC is the main UK government agency for funding research and training in engineering and the physical sciences, investing more than £800 million per year in a broad range of subjects – from maths to materials science, and from IT to structural engineering.
Economic and Social Research Council	The UK's largest organisation for funding research on economic and social issues. It supports independent, high-quality research which has an impact on business, the public sector and civil society.
Innovate UK	The UK's innovation agency. With a strong business focus, it drives growth by working with companies to de-risk, enable and support innovation. To do this, it works to: determine which science and technology developments will drive future economic growth; meet UK innovators with ideas in the relevant fields; fund the strongest opportunities; connect innovators with the right partners they need to succeed; and help innovators launch, build and grow successful businesses.
Research Councils UK	The RCUK mission is to optimise the ways that research councils work together to deliver their goals; to enhance the overall performance and impact of UK research, training and knowledge transfer; and to be recognised by academia, business and government for excellence in research sponsorship.

Research centres and institutes

British Geological Survey	A world-leading geological survey, focusing on public-good science for government, and research to understand earth and environmental processes.
SUPERGEN Bioenergy Hub	Aims to bring together industry, academia and other stakeholders to focus on the research and knowledge challenges associated with increasing the contribution of UK bioenergy to meet strategic environmental targets in a coherent, sustainable, and cost-effective manner.
Energy Systems Catapult	One of a network of elite technology and innovation centres set up by Innovate UK. It works with companies focused on exploiting the opportunities created by the need to transform global energy systems; not only playing a part in accelerating technology-based solutions, but also engaging with government to address the market mechanisms and business models that will be required to enable such solutions.
Environmental Change Institute	Established in 1991 'to organize and promote interdisciplinary research on the nature, causes and impact of environmental change and to contribute to the development of management strategies for coping with future environmental change.'
Energy Technologies Institute	A public–private partnership between global energy and engineering companies and the UK government. Its role is to act as a conduit between academia, industry and the government to accelerate the development of low-carbon technologies.

Centre for Graphene Science	This brings together the Universities of Exeter and Bath in internationally leading research in graphene. Its high-quality research environments and state-of-the-art equipment bridge the gap between the scientific development and industrial application of this revolutionary new technology.
International Institute for Applied Systems Analysis	An international scientific institute that conducts research into the critical issues of global environmental, economic, technological, and social change.
Joint Research Centre	The European Commission's science and knowledge service which carries out research to provide independent scientific advice and support to EU policy.
National Graphene Institute	The national centre for graphene research in the UK, drawing in specialists from across the globe. It houses state-of-the-art cleanrooms, plus laser, optical, metrology and chemical labs and equipment.
Nuclear Innovation Research Office	NIRO is hosted within National Nuclear Laboratory and is the body responsible for providing advice to government, industry and other bodies on R&D and innovation opportunities in the nuclear sector under the guidance of the Nuclear Innovation and Research Advisory Board (NIRAB). Collectively NIRAB and NIRO have a remit to: advise government and industry on nuclear innovation and R&D into future nuclear energy technologies; coordinate UK involvement in international nuclear programmes; ensure public R&D programmes align with industrial and energy policy aims; explore how funding can be secured, not only from government, but also from the private sector, EU and other international organisations and programmes related to future nuclear energy systems; and review at regular intervals the status of UK nuclear innovation and R&D.
National Nuclear Laboratory	A UK government-owned and -operated nuclear services technology provider covering the whole of the nuclear fuel cycle.
Sustainable Gas Institute	A unique academia–industry partnership, and collaboration between the UK and Brazil. It provides thought-leadership and drives research into the technology that could underpin a role for natural gas in the global energy landscape.
Tyndall Centre for Climate Research	Aims to see ongoing scientific research support society in making a timely transition to a sustainable low-carbon future. Its priorities for the next five years are to: support national and international public policy based on robust research; identify working solutions so that others will benefit from existing know-how; harness the benefits of climate change research for other social priorities; support a new generation of dynamic researchers; and strive to revolutionise international research, to ensure that it is itself low-carbon.
UK Geoenergy Observatories	The UK Geoenergy Observatories project will establish new centres for research into the subsurface environment. The knowledge generated will contribute to the responsible development of new energy technologies, both in the UK and internationally.
UK Energy Research Centre	UKERC carries out world-class research into sustainable future energy systems. It acts a focal point for UK energy research and a gateway between the UK and the international energy research communities. Its interdisciplinary whole-systems research informs UK policy development and strategies of public, private and third sector organisations.

Source: BEIS.

61. I recommend that the government, in its *Industrial Strategy*, conduct a fundamental review of energy research funding and its institutional organisations in the UK, and consider as one option the possibility of some amalgamation and mergers into a new UK Energy Research Laboratory, building links with the existing research centres.

62. Innovation is a separate but related problem. Unlike much R&D, in most cases it is a challenge for industry, not government. Once the internet had been developed, it was Microsoft, Apple and Google which rolled out new products and ideas, separate from government. State-driven models for mobile and broadband services have typically not been a success.

63. The literature on innovation stresses the problems of large-scale deployment, including the 'valley of death' as new technologies are rolled out into uncertain markets. The solution to this problem in the UK has been to grant technology-specific FiTs and CfDs, and to plan out the capacity for each of the technologies. There is always a fixed-price contract at a high enough price and for a long enough period that can produce a given level of deployment. However, this does not justify the policy, and there is merit in considering whether FiTs and CfDs are sufficiently well tailored to solve this innovation problem at least cost.

64. As discussed above, the ROCs and FiTs and low-carbon CfDs have left legacy costs on a very large scale, already comprising around 20% electricity bills. It is not obvious that what the UK has got as a result in first-generation renewables is optimal, but it is one that households and industry will live with for decades to come. That is why I recommend a legacy bank to inoculate the rest of the electricity system against these legacy costs, and why I also recommend that FiTs be brought to a gradual end as the long-run framework is established.

65. Innovation policy should focus on the key market failures specific to the innovation process. These largely concern the project's development – the construction costs and project development (CAPEX), ahead of generating the electricity. For this, the appropriate policy tools may include capital grants and special tax regimes for CAPEX. I recommend that as the FiTs are gradually phased out, the innovation dimension of industrial policy should focus on designing a general capital grants and tax regime. The Terms of Reference do not permit advocating specific tax changes, and thus this recommendation is confined to suggesting that such a system for innovation support be analysed.

66. It is not obvious that all or even most of the renewables technologies would survive the phasing-out of the FiTs, even with an overarching R&D programme and the capital grant and tax allowances

described above, without other changes. The key reason is not, however, the R&D or the innovation problems: it is the absence of a carbon price which is sufficient to achieve the carbon budgets and carbon target. It is for this (and other) reasons that I recommend a harmonised carbon price in section 10 to reflect the cost of carbon necessary to meet the targets. Only in the absence of such a price should the second-best (and more expensive) options of specific renewables support be added.

MAIN FINDINGS AND RECOMMENDATIONS

- Technology developments are changing the fundamental cost structure of the industry. An active demand side, storage and increasing zero marginal cost generation represent each and jointly a radical structural break with the past.
- The *Industrial Strategy* should set out a regulatory framework for EV charging.
- Government should conduct a fundamental review of the complex energy research funding and its institutional organisation.
- Government should consider amalgamations and mergers and the possibility of a new UK Energy Research Laboratory.
- Innovation policy should focus on designing a general capital grants and supportive tax regime rather than try to pick winners.

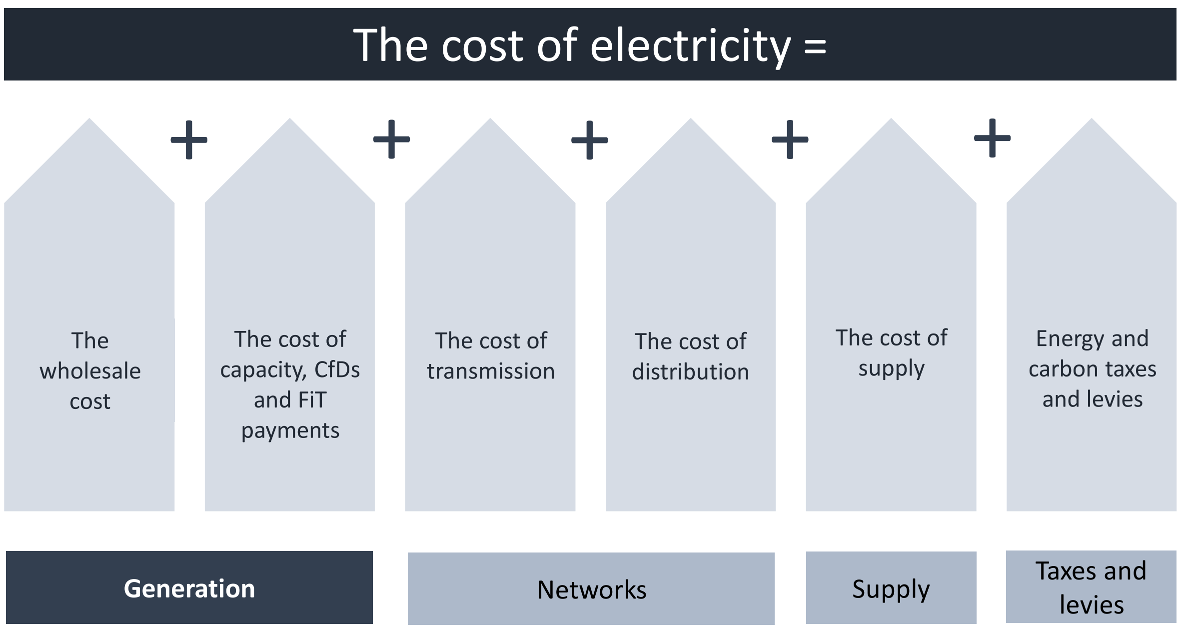
PART II

THE ELECTRICITY COST CHAIN

7. Electricity Generation

This section addresses:

- **the relationship between falling fuel prices and wholesale prices**
- **the limits to market power in the wholesale market from greater capacity and zero marginal cost generation**
- **the gradual decline of the importance of the wholesale market**
- **the success of the capacity auctions**
- **a gradual redesign of the FiTs**
- **how to lower the cost of capital through better designed contracts**
- **bringing the FiTs to a gradual close**



1. There are three dimensions to the cost of electricity generation – the wholesale market; the capacity auctions; and the FiTs and low-carbon CfDs. The wholesale market plays a critical role in scheduling plants for dispatch and ensuring that demand and supply are exactly matched at every point in time. The capacity market determines the availability of generating plants to meet security of supply. FiTs and low-carbon CfDs (and previously the ROCs) have ensured that renewables are brought online to meet the EU Renewables Directive, and that biomass and nuclear contribute to the CCA and the carbon budgets. Each of these three dimensions is explored in this section, starting with the wholesale market.

The wholesale market

2. Wholesale costs made up 36% of household electricity bills in 2016. The British wholesale electricity market is where generators and suppliers trade electricity ahead of final delivery to the consumer. Electricity is generated, transported, delivered and used continuously in real time, and supply must always match demand as electricity cannot (yet) be stored in large volumes. Energy market trade is physically balanced and financially settled (to ensure that supply meets demand). The wholesale electricity market is based on 'self-dispatch', whereby suppliers and generators contract to buy and sell power and have to pay 'balancing costs' if they under- or over-deliver. Moment by moment, the system operator takes action to keep the system in overall balance (ie, the amount generated equals the amount consumed). The cost of those actions determines the balancing costs to under- or over-delivering market participants.

3. Prior to the day of delivery, traders can set up contracts to buy or sell – called forward trading. This can protect them against short-term price uncertainties. On the day of delivery, electricity is traded in half-hour 'slots' (Settlement Periods). Each day is split into 48 Settlement Periods, with Settlement Period 1 equivalent to 00:00–00:30, up to 23:30–00:00 (Settlement Period 48). The trading arrangements are designed so that contracts are finalised beforehand; at a certain point (gate closure) it is no longer possible to change contracted volumes for a half-hour. Gate closure is currently set an hour ahead of the Settlement Period.

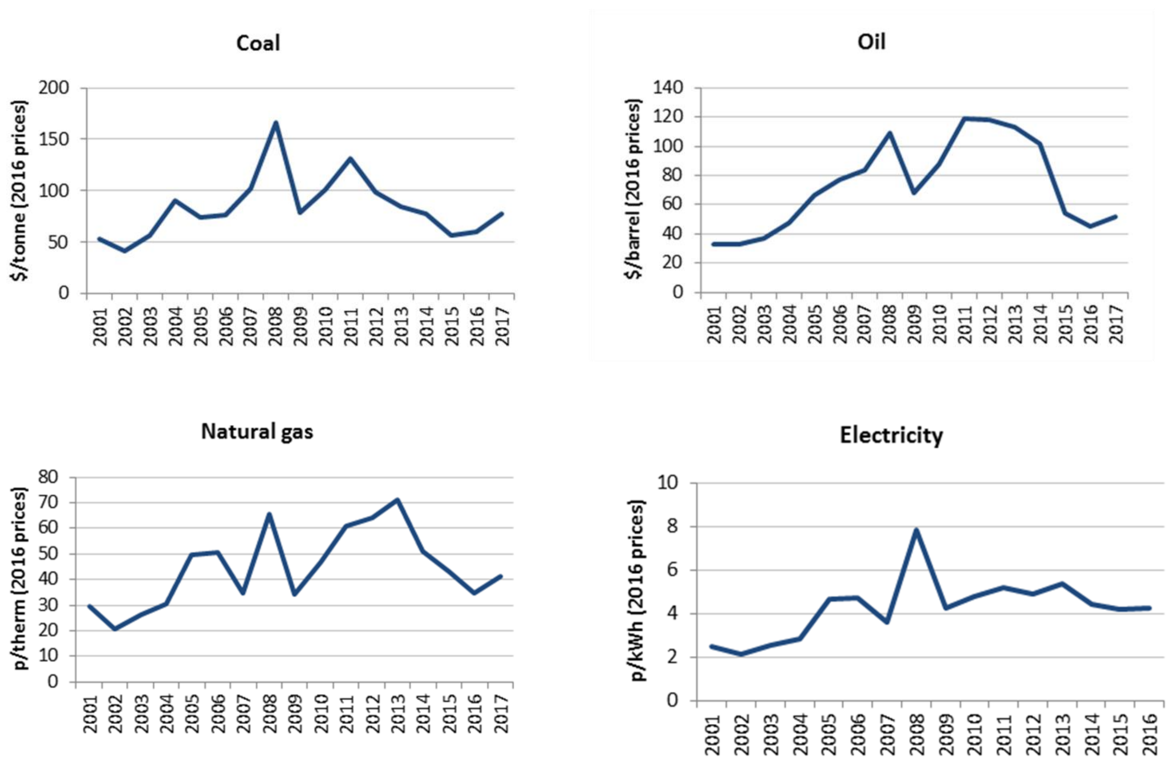
4. Once bilateral contracts are agreed, traders need to declare these so these volumes can be factored into the imbalance calculations. Notifications can be changed as the contract changes, right up until gate closure.

5. Imbalance pricing, known as 'cash out', is the price given to an excess or a shortfall of electricity produced. A party's contracted (traded) volume is compared with its actual metered volume in order to determine any imbalance. If a market participant under-generates or over-consumes, it will have to buy the extra energy at the System Buy Price. If it over-generates or under-consumes, it will need to sell the extra energy at the System Sell Price. These prices are not static, but are calculated according to whether the whole system has too much, or too little, power. When there is too much electricity on the system, the price calculation will include the actions taken to reduce generation or increase demand. When there is not enough electricity, the price calculation will be based on actions taken to increase generation or decrease demand. Imbalance prices can rise considerably when demand is high and additional generation scarce.

6. The variable costs of generation comprise the input fuel prices; the costs of operating the power station in generating the electricity, including water supplies for cooling; and the costs of waste disposal (eg, nuclear spent fuel, and ash from coal burning). In addition, power stations impose variable external costs through emissions. These include carbon and other GHGs, but also particulate emissions. There are a number of other externalities, which include the land and water environmental impacts, and the costs of transport of fuels to the power stations, and the emissions from stockpiles.

7. Starting with the dominant narrow costs, the primary fuel inputs are coal and gas, and the charts below show the trend in these costs over the medium term back to 2000, and the dramatic fall in costs after the crash in the commodity cycle in late-2014. This is a major reason why bills should be going down, net of the legacy costs identified in section 5.

FIGURE 26: WHOLESALE ENERGY COSTS

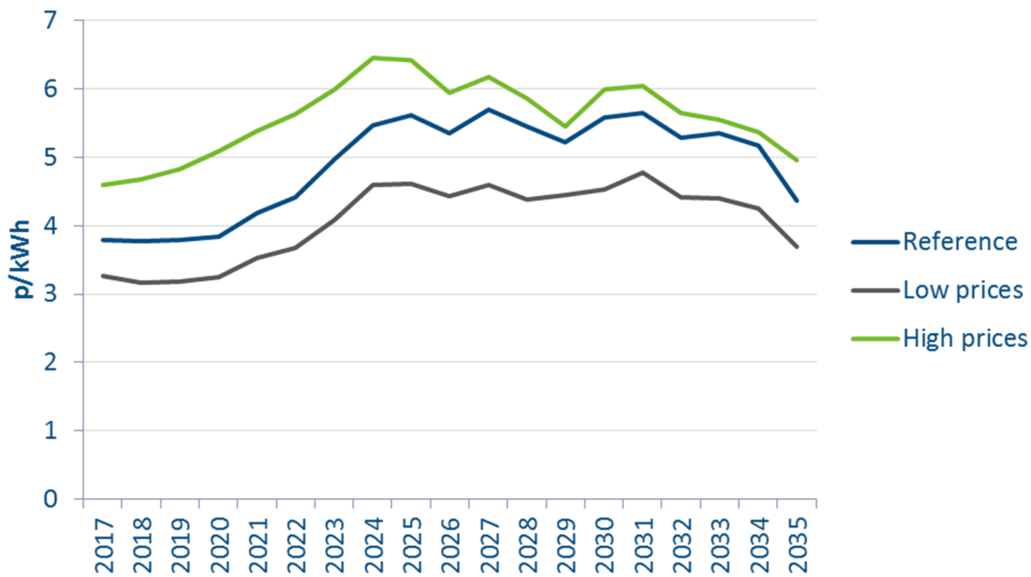


Source: BEIS (2017), Energy and emissions projections 2016; HM Treasury (2017), 'GDP Deflators at Market Prices, and Money GDP: March 2017' (Spring Budget 2017); IMF (2017), World Economic Outlook Database April 2017: United States GDP deflator index.

Notes: Published wholesale price forecasts deflated using published GDP deflators. 2017 actuals are averages of data published by Bloomberg (oil and coal) and ICIS (gas) for the period 01/01/2017–31/08/2017. 2017 actuals are not provided for electricity because of the seasonality of prices.

8. As noted in section 4, BEIS expects these wholesale electricity prices to now rise, before falling back gradually over the next decade, although never reaching the current levels again for the full period to 2030 and even beyond. This is the link to the 30% increase in gas prices BEIS expects to 2030, and included in the CCC's carbon budget calculations discussed in section 2. BEIS's high, medium and low scenarios are set out in the chart below.

FIGURE 27: WHOLESALE ELECTRICITY PRICE PROJECTIONS (2016 PRICES)

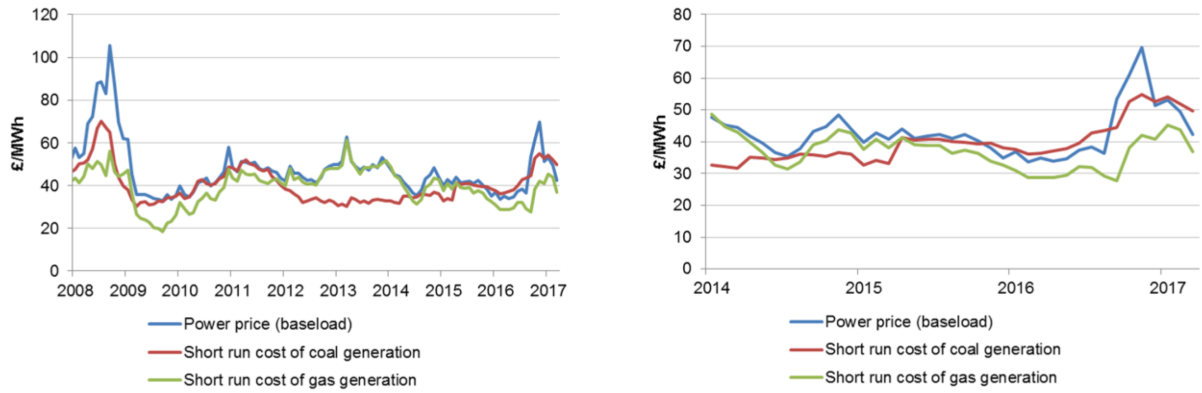


Source: BEIS (2017), Energy and emissions projections 2016.

9. The next step is to check whether and to what extent these input costs have fed through to the cost of generating electricity as represented by wholesale prices. This is shown by the spark spreads.

10. Public data on spark spreads is available only from 2008. These are shown in the charts below.

FIGURE 28: SPARK SPREADS, 2008–17 AND 2014–17



Source: Ofgem analysis of data from ICIS and Bloomberg, https://www.ofgem.gov.uk/data-portal/spark-and-dark-spreads-gb.

Notes: Short-run cost is the power price minus the clean spread for each technology. Clean spreads include carbon costs; the short-run costs of individual plant will vary, for example, based on the operating efficiency of individual plant.

11. Taking the evidence from the spark spreads, the future wholesale price can be expected to fall – and be (potentially much) lower than BEIS projects – if the gas prices do not rise 30% but rather fall back as discussed in section 4.

12. The link between the two is driven by the costs of the last generating unit necessary to meet the total demand on the system. As the demand increases, more power stations are drawn onto the system, and each is less efficient than the one before. The implication is that the price is likely to be closely correlated with the fuel input costs only if there is a sufficient margin of excess capacity available on a flattish supply curve.

13. The fall in capacity margins (described below) is greater than would be expected in a well-functioning competitive market. The scale of these investment failures is masked by the fact that demand has been unexpectedly low and falling, notably since the financial crisis in the last decade.

14. The explanation for the fall in capacity margins is in part a reflection of the fact that the market has not been designed to incentivise investment in spare capacity. The capacity auctions described below are a response, and going forward they should relieve this wholesale cost pressure.

15. There has been one further factor in the wholesale market which is likely to become more prominent in the future. The price is being depressed by increasing zero marginal cost generation from renewables. The experience of Germany, with periods of zero and even negative prices, is a sign of what may be coming here.

16. Thus, what may have been going on is a set of offsetting forces resulting in an outcome which just happens to produce a normal rate of return. Insufficient investment may have been offset by falling demand against expectations and more zero marginal cost renewables. Together, these countervailing forces might explain why the CMA in its report on electricity supply concluded that the rates of return were normal. Its reasoning may have been open to challenge, but the conclusion is largely sound.

17. The CMA relied on the analysis of rates of return. The fact that generators reported low returns should also be seen in the context of the scale of the shock of the financial crisis – the biggest since the 1930s – and the subsequent Great Recession, which meant that all sectors with similar economic characteristics suffered losses. The relevant comparison is between the returns to the electricity generators compared with the returns to other energy and mining companies over the period in which there was a profound negative demand shock. Compared with the impact of the 1980–82 deep recession, for example, the great difference is that, back then, the resulting capacity margin was 40% as demand fell away, whereas it was much lower after 2008.

18. The fact that wholesale market returns held up means that the exercise of market power in the generation market cannot be ruled out. Market power in generation was a significant problem in the 1990s, with repeated regulatory interventions. The restructuring of the wholesale market away from the Pool towards a voluntary, bilateral arrangement, as enshrined in NETA (New Electricity Trading Arrangements), and then BETTA (British Electricity Trading and Transmission Arrangements) when Scotland was integrated, worsened the transparency of the market. The background is provided in the box below.

HISTORY OF THE ELECTRICITY POOL, NETA AND BETTA

The UK electricity system was privatised in 1990, establishing the electricity Pool as the wholesale market mechanism through which electricity was traded in England and Wales.

The Pool and capacity mechanism: the Pool provided a set of rules determining how electricity should be traded in the wholesale market. National Grid, on behalf of the Pool, provided an estimate of national demand. Each day, generators submitted to National Grid a schedule of the availability of their power stations for each half-hour of the following day, and the price at which they would be prepared to generate. The price charged by the most expensive plant on the system for each half-hour determined the system marginal price for all electricity generated.

NETA: In 1997, the government launched a review into electricity trading arrangements, with a view to increasing competition and reducing costs. The New Electricity Trading Arrangements, introduced in 2001, were based on the concept of bilateral trading between generators, suppliers, traders and customers through futures markets and short-term power exchanges. NETA introduced the following:

- Generators would be responsible for determining the level of output from each of their units (rather than being scheduled by National Grid, as per the Pool).
- Generators would be paid at bid price, rather than the price of the most expensive bid for the relevant half-hour.
- Trading would continue until 3.5 hours ahead of real time (under the Pool, offers were made a day ahead).
- The Balancing Mechanism would incentivise flexibility and penalise plants causing imbalance (any difference between actual generation and the contracted amount).
- Cash-out prices would target the costs of balancing the system on to the generators and suppliers causing imbalance, providing incentives for generators to balance their contractual and physical positions.

BETTA: NETA applied only to England and Wales. Until BETTA was introduced, Scottish suppliers were required to either own generation plant or negotiate directly with generators (or import via the interconnector). Scottish prices were set at the same level as Pool prices. The British Electricity Trading and Transmission Arrangements were proposed by Ofgem to implement a fully competitive British-wide wholesale electricity market. BETTA was introduced in 2005 through the following reforms:

- extending NETA to the Scottish market;
- creating a single body to operate the transmission system – National Grid took on this role (previously in England and Wales the transmission system was run by National Grid, and in Scotland by ScottishPower and Scottish & Southern Electricity);
- reforming access to the transmission system.

Source: BEIS.

19. In a well-functioning wholesale market there would be deep, liquid and transparent trading arrangements. This is best achieved through compulsion, and indeed this is what happened in the original electricity Pool model introduced at privatisation. All power dispatched had to go through the Pool, and be bid into the Pool, save for very small units.

20. This model was jettisoned for two reasons, neither of which was convincing at the time. The first was the Austrian argument that compulsion was a 'bad thing', and that as the electricity industry moved towards a normal commodity market, the participants should be free to choose the most efficient trading arrangements, including by contracting outside the Pool in bilateral arrangements. The second was that the incumbent generators were gaming the Pool.

21. The first argument neglects the basic facts about electricity: that supply and demand have to be instantaneously matched, and that a merit order is a price discovery mechanism to ensure economic efficiency. All sorts of contracts could be written against the Pool, but the Pool could still play the central role. No other market arrangement could be so liquid (because everything had to go through the Pool), and therefore any other arrangement would be less liquid, and hence less efficient. It is no accident that after the Pool was abolished, Ofgem had to repeatedly intervene to ensure liquidity, including its most recent cash-out reforms.

22. The second argument is simply not a good reason for abandoning the Pool. It was the Pool that revealed the exercise of market power – transparently. The solution to this problem was to break up the market power. Instead the regulator allowed the generators to vertically integrate, and it was the combination of abandoning the Pool and vertical integration which increased market power, blocked off merchant entry, and cemented the role of the Big Six right through the first decade of this century. NETA, which effected these retrograde steps, was a mistake. It is not even entirely clear that the merit order was always preserved.

23. In terms of the costs of operating power stations and the provision for decommissioning, in theory these are recovered by the companies through the differential between the SMP, which determines the wholesale price, and the stations' particular costs. In the absence of capacity payments, the integral between the two is also the way in which the power station earns its return on capital and recovers its investment costs. This gap between the SMP and the SRMC of the generating unit should, in a competitive equilibrium, yield a normal return over the life of the plant. Typically, when the plant is new, it will run lots of the time and be able to depreciate fast, then move up the merit order as other, more efficient, plants come on the system.

24. There are three reasons why this might not work: the overhang of a (necessary) capacity margin for security of supply; the intermittency of renewables; and the growth of zero marginal cost electricity supplies.

25. Security of supply requires excess capacity, and excess capacity weighs down the SMP, thereby reducing the gap between the SMP and SRMC, and hence limiting the recovery of capital costs. The impact will be to render new investments at the margin uneconomic: they will have negative net present values. Therefore, the security of supply excess margins require an additional payment over and above the wholesale price. This is why, independent of renewables, an electricity market needs some sort of capacity payment. To remove this with the introduction of NETA was a mistake, and would have been a really serious mistake but for (in this respect) the lucky accident of the economic crisis and the fall of demand relative to expectation. Fortunately, this aspect of NETA has been rectified now with the introduction of the capacity mechanism, discussed below.

26. The second reason the wholesale market will not recover the full costs of investments is the coming of intermittent renewables. These have lower SRMCs compared with the conventional plant, and will as a result displace them when they run – when the wind blows and the sun shines. Because they are intermittent, this displacement of conventional plant is intermittent too. The result is that for gas plant in particular, gas supplies have to be interruptible too, because gas power stations are now rendered intermittent. These conventional gas plants can no longer rely on an early stage high load factor. Intermittency raises the costs of conventional power, and its costs of capital.

27. This problem is combined with a third: the renewables are mostly zero marginal cost. This depresses the wholesale price, and in a fully decarbonised world, the wholesale price might be zero too. On route to decarbonisation, the wholesale price can be expected to fall. The result is that the revenues from the wholesale market will increasingly fall short of the costs of new entrants in conventional power, and hence investment will be insufficient, even in the presence of market power.

28. It is these second and third problems which rendered new gas investment uneconomic in the NETA market structures, and have necessitated the bolting-on of the capacity market. The next section explores how this new capacity market will move from the bolt-on to the central market for electricity in the long-run framework set out in section 11.

29. For these reasons, any concerns about market power in the wholesale market are likely to weaken over time. The issues will turn more on the price being too low to support investment, and the issue of how to schedule a merit order with lots of zero marginal cost generation, rather than on the price

being too high. The CMA may not have properly appreciated how market power might have operated in the past, and paid too much attention to rates of return; but looking forward, this is not a priority area for concern about the cost of energy. The falls in the fossil fuel prices should be feeding through from the wholesale market into customers' bills. It is with this passing-through that the problem lies, and with suppliers' hedging and market power, together with other offsetting cost increases. The failure to translate this into lower customer and industry prices is a supplier problem, not a generation one, and is discussed in section 9.

30. The wholesale market works on a day-ahead bidding system, and then a process between the day ahead and the actual dispatch time during which balancing and flexibility is brought into play.

31. There are two central issues with this period. The first is the extent to which auctions should drive the outcomes and determine who is dispatched at what price and how flexibility costs and options are reflected in markets rather than by a central buyer. The second is whether this market can provide the non-firm opportunities for zero marginal cost intermittent renewables and the basis for trades which convert non-firm into firm power for the unified EFP capacity auction I recommend later in this section.

32. National Grid has the duty to make sure the system adds up, and there is one school of thought which sees the problem of balancing and flexibility as a conventional command-and-control problem, to be decided by a central body. Thus it would be for National Grid to take an active role in providing the direct incentives to develop back-up, flexibility through, for example, the demand-side responses, storage options, and peaking plants. The second view is that, provided there are serious penalties for failure to deliver, and ultimately emergency standby capacity, this can be left to markets through auctions and competitive bidding.

33. The command-and-control approach has historically dominated. However, the IT that is facilitating smart metering and smart grids also helps to allow markets to take up the challenges. The usual conditions need to apply – notably deep, transparent, and liquid trading. Ofgem has gradually brought in more powerful incentives and penalties, and these have contributed to the improving performance of those close to dispatch markets.

34. If the renewables and other low-carbon zero marginal cost generators are incentivised to bid for firm power contracts, they will have a powerful incentive to help develop and engage in the wholesale market where the intermittency is more predictable and therefore further ahead than

one day. They will have every incentive to develop flexibility contracts and to invest directly in back-up.

35. The task of the system operators is to be clear what is being bought in terms of matching supply and demand, and in the long-term framework not to get involved in defining particular technologies, and the segregating-out of different markets with different incentives. The problem is a simple one: how to make supply equal active demand at each point in time. In the short-to-medium term, the balancing exercise is for the NSO. In sections 8 and 11 I recommend an institutional structure to harmonise the interests and conduct of the NSO and RSOs.

36. The workings of these energy-only markets, and their ability to translate non-firm power into firm power (which is what the energy market does at the point of dispatch), play a crucial role in the gradual removal of the FiTs and low-carbon CfDs. For these contracts fix a price for electricity generated independent of the market, whereas the development of the energy-only markets with balancing and flexibility mechanisms depends precisely on variable price bids and outcomes in order to efficiently allocate resources.

Capacity markets

37. The past problems in the energy-only wholesale market were partly the consequence of a lack of an incentive to create an optimal capacity margin, and partly caused by the increase in intermittent zero marginal cost renewables generation.

38. As these problems became manifest, late in the day, the government introduced a capacity mechanism into the electricity market. As already noted, the rationale was a simple and enduring one: no rational private company would deliberately engineer a situation of excess capacity above the mean expected demand, because this would depress the marginal costs and hence the price. The higher the excess supply, the lower the wholesale price, in the absence of the exercise of market power. The extra twist comes from intermittency and zero marginal costs.

39. The implication is that unless the private sector is paid to provide an excess capacity margin it will not do so. In most markets this would not much matter, but in electricity the absence of storage (still largely the case) means supply must meet instantaneous demand, and so when demand spikes, there needs to be a margin to take up the slack. Add passive demand too, and all the shocks need to be absorbed by this excess capacity margin. In time, these problems may go away, but for now they are pressing and real.

40. The low capacity margin has reflected the absence of appropriate investment incentives, masked by the unanticipated lower demand. The capacity market solves this problem. As the old legacy assets in coal and nuclear described in section 5 come off the system, the capacity auctions can in principle provide for any level of new capacity required. It is the correct instrument to achieve the security of supply objective.

41. The original privatisation arrangements did have a capacity mechanism alongside the Pool. The system therefore did have the right approach, but there was a serious design flaw in this capacity mechanism, and this flaw enabled the generators to play games with declaring plant availability, and hence reap gains from market power. In principle, the mechanism combined a loss of load probability (LOLP) with a value of lost load (VOLL). In practice, it proved a licence for market abuse.

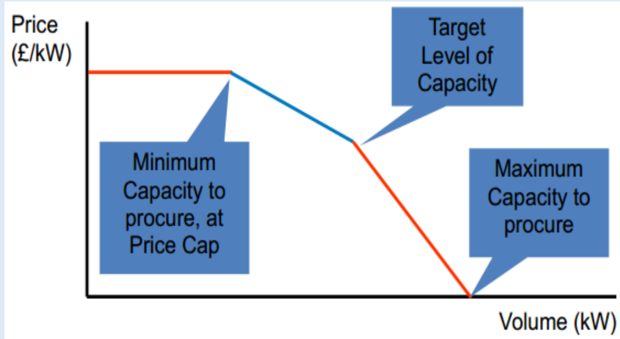
42. Erroneously, and with major consequences for the cost of energy, it was concluded that the capacity mechanism should be abolished through the NETA reforms, and nothing should be put in its place. As noted above, it took a decade for the scale of the mistake to be realised (in part shielded by the impacts on demand of the economic crisis), and eventually a new capacity market was created.

43. The new capacity market auction is the competitive process to award capacity market agreements to meet the target capacity for the relevant delivery year. The capacity sought in the auctions is described by the demand curve which captures the trade-off between the cost of capacity and security of supply according to the auction parameters specified in the auction guidelines. The demand curve is established ultimately by government, and based on National Grid's Electricity Capacity Report. This is the correct role for government: to effectively set the required margin. It is the job of the system operators to deliver it.

44. As with the original capacity mechanism, what matters is the precise market design. The new capacity mechanism has two key advantages: it is based on auctions; and it places the decision about the quantity of supply with the government and National Grid. At a stroke, the market was transformed from one in which private companies made decentralised decisions about how much generation to invest in, with National Grid merely the responding body with a duty to facilitate connections, to a centralised central buyer system, in which (with the FiTs and CfDs) all new investment is in practice determined by government-backed contracts.

45. The diagram below shows the format of the auction. The details are then set out, followed by a summary of the auctions so far.

FIGURE 29: AUCTION FORMAT



The auction is a descending clock, pay-as-clear auction. This means that:

- the price starts at the auction price cap (as set out in the auction guidelines);
- the price is reduced in each round by a set decrement;
- bidders submit exit bids to retract a capacity market unit (CMU) from the auction at a particular price;
- an exit bid is the minimum price at which a bidder would accept a capacity agreement;
- as the price descends and exit bids are submitted, the total remaining capacity decreases with price;
- the auction ends when a price is reached at which the total remaining capacity is equal to the capacity demanded – the 'clearing price';
- successful CMUs (those that have not submitted exit bids above the clearing price) all receive a capacity agreement at the clearing price.

The auction is managed by National Grid and conducted via a web-based auction system.

PRICE-MAKERS AND PRICE-TAKERS

CMUs that are price-takers may choose to submit exit bids only at a price lower than the 'price-taker threshold', which is an auction parameter determined by the Secretary of State and set-out in the Auction Guidelines. By default, all existing CMUs are price-takers. CMUs that are price-makers are free to submit exit bids at any price less than the auction price cap

DURATION BID AMENDMENTS

New and refurbishing generating CMUs may choose a capacity agreement of more than one delivery year (up to the CMU's maximum obligation period). If successful, the CMU will receive the auction clearing price each delivery year.

Below is a summary of capacity auctions that have already taken place. Note, however, that this does not include the Transitional Arrangements (DSR-only) auction.

TABLE 8: CAPACITY AUCTION SUMMARY

	Delivery year: 2017/18, T–1	**Delivery year: 2018/19, T–4**	**Delivery year 2019/20, T–4**	**Delivery year 2020/21, T–4**
Participated	59.3GW	65GW	58GW	69.8GW
Successful	54.4GW	49.3GW	46.3GW	52.4GW
Clearing price	£6.95/kW/y	£19.40/kW/y	£18.00/kW/y	£22.50/kW/y
Existing plant	50.1GW	39.4GW	42GW	44.5GW
New generation	1.7GW	2.6GW	1.9GW	3.4GW
of which CCGT	-	(1.6GW)	(0.8GW)	(1.5GW)
Refurbished plant	-	7GW	-	0.8GW
Existing DSR	0.2GW	0.17GW	0.45GW	0.44GW
Interconnectors	2.4GW	-	1.8GW	2.3GW
MW capacity by type				
CCGT	22,062	22,259	21,808	22,596
Coal/biomass	10,470	9,232	4,684	6,089
Nuclear	7,878	7,876	7,575	7,878
CHP and autogeneration	4,604	4,235	4,206	4,407
Interconnector	2,362	–	1,862	2,342
Storage	2,710	2,699	2,617	3,201
OCGT and reciprocating engines (including diesel)	3,432	2,101	2,430	3,788
Hydro	679	682	695	711
DSR	209	174	476	1,410
Oil-fired steam generators	17	-	-	-
Total	**54,433**	**49,258**	**46,354**	**52,425**

Source: BEIS.

46. There have been two ‘surprises’ so far with the capacity auctions. First, the winners have not been mainly CCGTs, but rather a wave of small-scale diesel generators and small open-cycle gas turbines (OCGTs), in turn giving rise to a debate about the embedded generation benefits, and new DSR and storage. The CCGT that won through in the first auction has not materialised. Second, the prices have been much lower than expected. As a result there appears to be the prospect of an almost infinite number of such smaller low-cost plants and lots of DSR and storage as well at a level supply curve cost. Capacity is no longer just about building large-scale power stations without storage and DSR as alternative options. These lower the costs as set out below.

TABLE 9: THE COSTS OF CAPACITY AND AUCTION RESULTS

Capacity market auctions (delivery year)	**2017/18**	**2018/19**	**2019/20**	**2020/21**
Target volume	53.6GW	48.6GW	45.4GW	51.7GW
Volume procured	54.4GW	49.3GW	46.4GW	52.4GW
Clearing price (£/kW)	£6.95/kW	£19.40/kW	£18/kW	£22.50/kW
Total gross cost of the auction (in delivery year)	£380m	£956m	£835m	£1.1bn
Average annual impact on household bills[1]		Gross (on bills): est. ~£14 over 15 years, Net (on bills): est. ~£2 over 15 years		

Source: National Grid Reports: T-4 2014 Report; T-4 2015 Report; T-4 2016 Report; Early Auction Report; DECC (2016), 'Security of Supply and Capacity Market Impact Assessment' (provides an estimate range on possible impacts on prices and bills on modelled scenarios); DECC (2013), 'Electricity Market Reform – Capacity Market Impact Assessment' (provides an estimate range of possible impacts on prices and bills on modelled scenarios); DECC (2014), 'Electricity Market Reform – Capacity Market Impact Assessment'.

Note: [1] Average annual domestic electricity bill impact over the period 2016–30 (2014 estimate, 2012 prices).

47. The capacity auctions will be critical in ensuring that the closure of the old coal and old nuclear over the period to 2025 and 2030 (before new nuclear comes on) is offset by sufficient new capacity coming onto the systems in an orderly way. These challenges were set out in section 5.

48. All this closing capacity will have to be replaced in a context of a rising demand for electricity for transport and an uncertain, more general electricity demand picture (not least because of uncertainty about energy efficiency developments). Critical to this is how, to what extent, and by when the government's nuclear ambitions are delivered – both the amount of new capacity that will be built, and the uncertainty about precisely when it will come on stream. The difference to the system of up to 13GW of new nuclear capacity versus none, or just Hinkley, is an enormous uncertainty for the system operator to handle. Since, as noted earlier, nuclear is a very political technological choice, I recommend that government should as a matter of urgency give guidance to the system operator as to what measures it should take to mitigate this large-scale system risk, and the extent to which extra capacity should be auctioned 'just in case' new nuclear is either late or not delivered. Failure to do so could result in sharp spikes in the wholesale market.

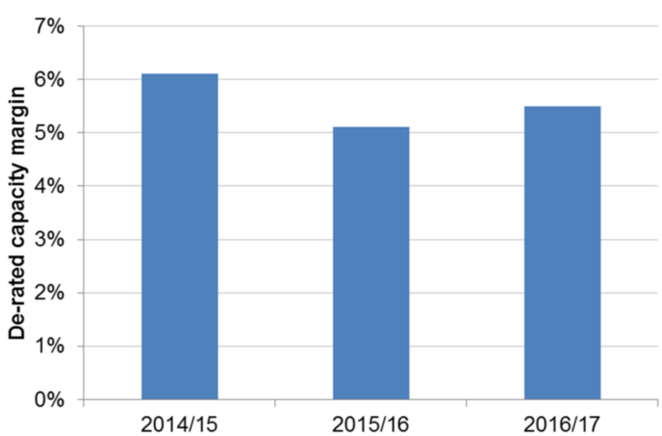
49. A final complication is the possibility that, in the event of one or more global nuclear accidents, the safety standards might be further tightened, and in the process existing stations are retired earlier (perhaps instantaneously) or new ones are delayed for regulatory safety reasons. Politics is again always a key feature of decisions. In the last decade, Germany has done two U-turns on its nuclear

fleet, having first extended the lives of existing nuclear power stations and then deciding to close them all by 2022. There have also been suggestions that France may close a number of nuclear reactors by 2022. No electricity system is immune to the risk of changes to the outlook for nuclear due to a change in political perspective, and this should be taken into account in setting the capacity margin and network resilience to meet the security of supply objective.

50. There is no doubt that a lot of new investment in capacity will be required over the coming decade through to the end of the Fifth Carbon Budget period. As much of this as possible should go through the capacity market auctions. It is widely assumed that this entails a rise in the cost of energy. As noted in section 5, there is, however, no obvious reason why this should be the case. The extra capacity to meet existing and new demands for electricity will be contracted on a pay-when-delivered basis, and will be of a modern vintage of technology. There will be new customer bases, including in transport; and new product markets, such as air-conditioning, digital household services, and digital manufacturing and services. Wholesale price reductions should offset capacity auction costs. As with other sectors with rapid technical change, and often rapid stranding, such as communications, new investments with positive net present values offer profitable opportunities and prices can fall, not rise. Prices rise only if the government commits to more expensive technologies.

51. As the time horizon opens up and the level of uncertainty grows, there is a policy choice to make about 'how close to the wind to sail', and hence how much capacity to auction. As the chart below illustrates this is already tight.

FIGURE 30: HISTORICAL DE-RATED CAPACITY MARGIN FOR GREAT BRITAIN



Source: National Grid Winter Reports (numbers sourced across several reports).

52. The capacity gap can be closed by the capacity auctions and the new plethora of options including peaking plant, DSR and storage. The required level of capacity leaves open the choice of technologies and, in practice, the portfolio necessary to meet the climate change targets in general and the carbon budgets in particular. The closing of the gap, and hence the level of the security of supply objective, is a matter of contracting in a flexible way for the required margin, and this is a matter for the system operator.

53. There are a number of practical issues in determining how much capacity to auction, and the details matter. These include uncertainty about future demand; delineating what is and is not capacity; taking account of the risks of non-delivery; and different time horizons.

54. As with any set of market design rules, there are no perfect answers to these questions. The best that can be achieved is being roughly right. The capacity market can be defined by complete but imperfect *ex ante* rules, or be subject to discretion. Given the speed and scale of the technological change identified in section 6, there is a powerful case for an element of the latter. This is where the system operator model comes in, and is one reason why it should be a public interest body and separate from other parts of the industry. The independent NSO I recommend in section 8 should be able to vary the amount and frequency of its auctions, and to vary its designs and rules as technology and demand change over time, subject to ministerial guidance, and in particular the annual statement to Parliament I recommend in section 12.

55. This discretion is also important because however well markets and capacity contracts are designed, they will always be incomplete, and there will always be surprises. For this reason, the capacity market needs to be overlaid by a residual duty to ensure supply. I recommend that this should be placed on the NSO, and it must have the discretion to act, and sometimes act quickly, as events arise.

56. Among these predictable surprises to which the NSO will have to respond, there are two areas of particular importance: the composition of capacity; and the cyber and other threats to security. On the composition of capacity and the fuel mix, security of supply is a system property, and there are interactions between different types of capacity. Thus if the cheapest options from the auctions are small-scale diesel and OCGT plants, there may need to be a view taken about how these work for the benefit of the system as a whole, and whether there are additional consequences of having an unbalanced portfolio of capacity on the system. To clarify these issues, the NSO should set out the broad parameters for the preferred balance of the portfolio, and have the power to vary outcomes

on this basis. I recommend that the guidelines should be issued by government and published on a regular timetable.

57. Cyber and other broader security challenges to the electricity system must also be taken into account by the NSO. Some plant is more vulnerable than others, on account of the technical characteristics and the location. The NSO, in auctioning capacity, should take these additional security issues into account. For obvious reasons, these cannot always be made public to the bidders, and there may be times when the NSO cannot declare why particular choices have been made. Government should have the powers to instruct the NSO regarding such matters. As a result, the NSO should not be formally committed to accepting the lowest capacity auction bid, but rather use a scored approach.

FiTs and low-carbon CfDs

58. In the current electricity market, fixed-priced capacity contracts sit alongside fixed-priced FiTs and low-carbon CfDs. Whereas the broad design of the capacity auctions is reasonably good, the design of the FiTs and CfDs has a number of weaknesses. Neither the ROCs before the FiTs, nor the FiTs themselves are the only or best way of achieving the EU Renewables Directive target. Post-Renewables Directive and Brexit, there is considerable scope to reduce the costs of achieving the carbon budgets, as the FiTs and CfDs remain for a transitionary period, through smarter contracting.

59. Much of renewables policy has evolved as the renewables deployment has unfolded, and in the context of the pressures created by the EU Renewables Directive and as a result of intensive lobbying. There have been four main interventions along the way: the RO, the banding of the ROCs, the FiTs, and the FIDeR. These are set out in the table below.

TABLE 10: RENEWABLES SUPPORT SCHEME TIMELINE

2002	RO introduced in UK
2005	RO introduced in Northern Ireland
2009	Banding introduced under the RO
2010	FiT scheme introduced
2011	Government announces intention to close the RO in 2017 and transfer to the CfD scheme
2012	First RO comprehensive banding review (implemented in 2013) Review of the FiT scheme (review of tariffs and other scheme administration issues)
2013	FIDeR launched
2014	Eight projects offered contracts under FIDeR, allocating the first CfDs
2015	Review of the FiT scheme (review of tariffs, introduction of deployment caps and other scheme administration issues) RO closes early to large-scale solar Results of first CfD allocation round announced
2016	RO closes early to small-scale solar and onshore wind
2017	RO scheme closes to new applications Results of second CfD allocation round announced
2019	Final deadline for RO applications (for stations with grace periods) FiT generation tariff ends

Source: BEIS.

60. The RO was set up in 2002. ROCs were offered to show compliance with the overall target obligation. The second version added in banding to the ROCs, so that now each renewables technology was treated separately. The third version is the small-scale feed-in tariff (ssFiT) (hereafter simply called FiTs), which replaced the RO and the ROCs. The fourth version is the FIDeR and the associated CfDs (which I here refer to as low-carbon CfDs). The FiTs and CfDs continued to discriminate by technology and ignored (as with the RO and the ROCs) the associated system costs. Each of the main support mechanisms are now described in more detail.

Renewables Obligation

61. The RO has been the main financial mechanism for incentivising the deployment of renewable electricity capacity in the UK.

62. It requires licensed electricity suppliers to source a specified proportion of the electricity they provide from renewable sources (the ‘Obligation’). Generators are issued Renewables Obligation Certificates (ROCs) for the renewable electricity they generate. Generators then sell their ROCs to suppliers, which use them to demonstrate that they have met their obligation.

63. The idea was simple: the RO places an obligation on UK electricity suppliers to source a specified proportion of the electricity they supply to customers from renewable sources. This proportion – the Obligation – is set each year for the year ahead. It specifies the number of ROCs that a supplier must provide to the scheme administrator, Ofgem. Suppliers failing to present enough ROCs to meet their obligation in full pay a penalty, called the 'buy-out price'.

64. Ofgem issues ROCs to generators in relation to the renewable electricity they generate. Generators sell those ROCs to suppliers or traders, with or without the electricity generated, as tradeable commodities. This allows them to receive a premium in addition to the wholesale price of their electricity.

65. After Ofgem's administration costs have been deducted, the money it collects in the buy-out fund is recycled on a *pro rata* basis to suppliers that presented ROCs. Suppliers that do not present ROCs do not receive any portion of the recycled fund. This encourages them to choose ROCs over the buy-out price.

66. It is assumed that the cost of the RO to suppliers is passed on to consumers through their energy bills. The total cost that can be levied on consumers through the RO is controlled through the LCF.

67. There is no formal definition of the RO, but the Electricity Act 1989 gives the Secretary of State the power to '*impose on each electricity supplier … an obligation to do what is set out in subsection (3) (and that obligation is referred to in this section and in sections 32A to 32C as the "renewables obligation")*'.

68. In July 2011, as part of the Electricity Market Reform White Paper, the government announced its policy intention to close the RO to new capacity in 2017 and transition to the CfD.

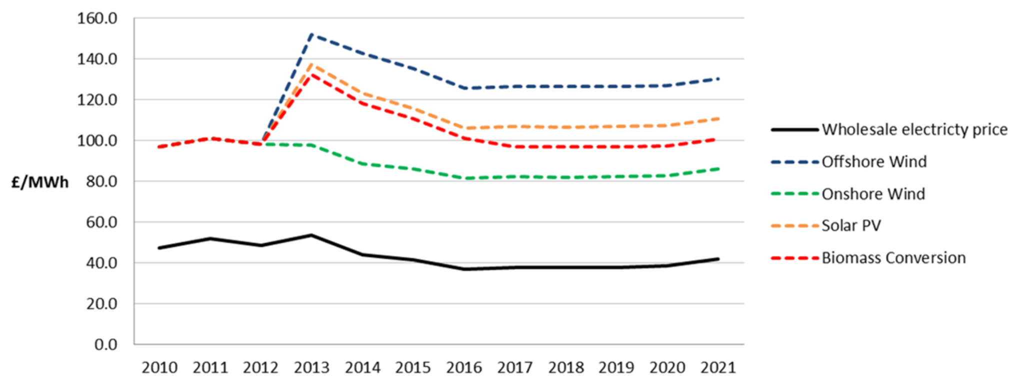
69. In 2015, a forecast overspend relative to the LCF budget was projected for the first time. To address this, further interventions (and complexities) were introduced. The government took actions to control RO spend, including:

- closing the RO early to small-scale solar (up to 5MW) on 31st March 2016;
- removing guaranteed rates of support for generators of electricity from biomass co-firing and biomass conversions in July 2015;
- closing the RO early to onshore wind in May 2016 under the Energy Act 2016.

70. The RO closed to new applications in March 2017 (with exceptions that extend the deadline for some projects to January 2019 in Britain and March 2019 in Northern Ireland).

71. Most projects accredited under the RO will receive support for 20 years. The chart below shows the RO support prices. They are a big part of the legacy costs identified in section 5. ROCs will not be issued in respect of any electricity generated after 31st March 2037.

FIGURE 31: WHOLESALE PRICES VS RO SUPPORT



Sources: BEIS, from the support rates calculated using 2016/17 buy-out price and banding from Ofgem website: https://www.ofgem.gov.uk/publications-and-updates/renewables-obligation-ro-buy-out-price-and-mutualisation-ceilings-2017-18 and https://www.ofgem.gov.uk/system/files/docs/2017/03/ro_guidance_for_generators-130317.pdf; BEIS (2017), Energy and emissions projections 2016.

Notes: Support rates in 2016/17 prices; wholesale electricity prices in 2016 prices; support rates include the average wholesale electricity price (ie, they are not additional to the wholesale price).

72. The RO has undergone various reforms since it was introduced. The most significant of these was the introduction of banding in April 2009, which moved the RO from a mechanism which offered a single level of support (1 ROC/MWh) for all renewable technologies to one where support levels vary by technology. This was a major change, increasing complexity and creating big opportunities to lobby hard for a favourable banding. The first comprehensive banding review was concluded in 2012 and was implemented in April 2013.

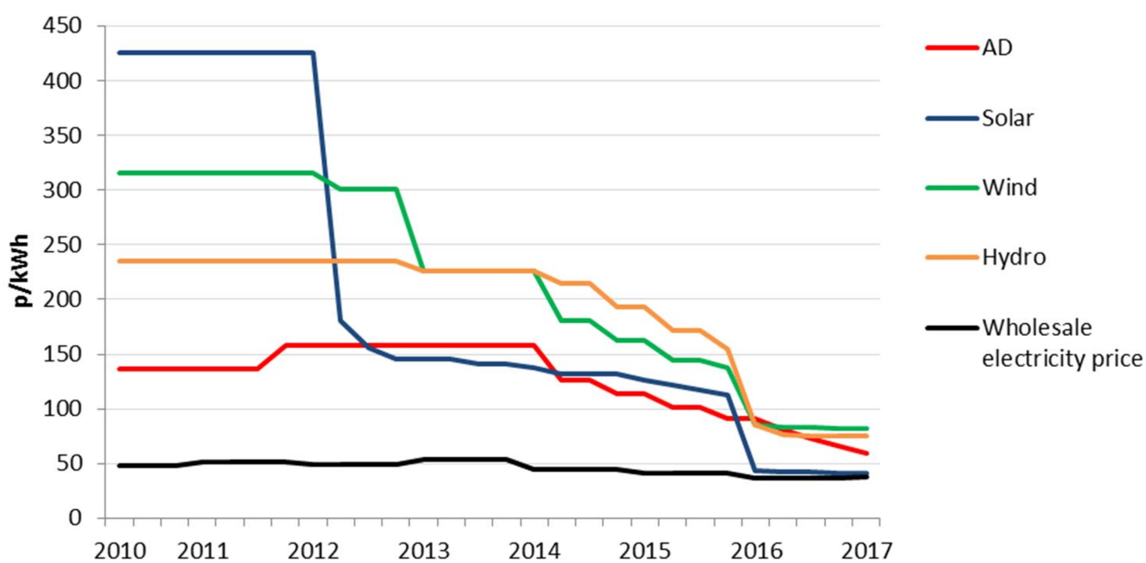
Feed-in tariffs

73. The FiT is a payment which small-scale generators of renewable electricity can apply for. Under the FiT, generators receive a set amount for each kWh of electricity generated. Generators are also eligible to receive export payments on electricity which is not used and is sold back to their energy supplier. Payments to generators are made by electricity suppliers and then passed on to consumers through electricity bills.

74. The FIT scheme was introduced in 2010, under the Energy Act 2008. The technologies supported under FITs are: solar PV, onshore wind, hydropower, anaerobic digestion (AD), and micro-combined heat and power (CHP) (<2kW).

75. There have been two substantial reviews to the FIT scheme, one in 2012, and one in 2015. These added further complexities to the scheme, in some cases as the result of lobbying pressures. The 2012 review of tariffs and other scheme administration issues led to four changes (and further complexities), including: strengthening the link between FITs and energy efficiency; index-linking of tariffs; changes to degression rates and thresholds; and a reduced tariff lifetime for solar PV. The 2015 review of tariffs introduced deployment caps and other scheme administration issues, and led to three further detailed alterations (and further complexities): changes to the levelisation exemption for imported renewable electricity; eligibility date requirement for energy efficiency rating; and changes to how some standards are referenced. Sustainability criteria and feedstock restrictions for AD were introduced in 2017 (along with further complexities). The costs of the FiTs are set out in the chart below.

FIGURE 32: WHOLESALE PRICES VS SSFIT GENERATION TARIFFS



Sources: BEIS, from Ofgem tariff tables (2015/16 prices) and representative tariff bands; BEIS (2017), Energy and emissions projections 2016.
Notes: Tariffs in 2015/16 prices; Wholesale electricity prices in 2016 prices.

76. This is a classic case of starting out with a specific intervention, leading to unintended consequences, leading to more interventions, and resulting in greater complexity. It is what might be called the ‘sticking plaster’ approach to the evolution of policy.

Contracts for difference

77. The CfD scheme was introduced through the 2013 Energy Act, alongside the other aspects of EMR including the capacity market.

78. A CfD is a private law contract between a low-carbon electricity generator and the Low Carbon Contracts Company (LCCC), which is government-owned. It is a contract for certain payments which are to be funded by electricity suppliers, and which a CfD counterparty is required to enter into. A generator party to a CfD is paid the difference between the 'strike price' – a price for electricity reflecting the cost of investing in a particular low-carbon technology – and the 'reference price'– a measure of the average market price for electricity in the British market.

79. The EMR policy document describes the 'Feed-in Tariffs with Contracts for Difference' as a mechanism to support investment in low-carbon generation. In the interest of encouraging low-carbon electricity generation, the Energy Act 2013 gives the Secretary of State the power to make regulations about CfDs between a CfD counterparty and an eligible generator.

80. The stated aim of the CfD is to stabilise returns for generators, removing their long-term exposure to electricity price volatility and substantially mitigating the commercial risks faced by these projects. It has been a significant subsidy.

81. Levels of support were initially set by the government; however, the CfD has moved towards more competitive forms of allocation for all technologies.

82. In 2013 the government launched FIDeR, a programme designed to enable developers of low-carbon electricity projects to take final investment decisions ahead of the CfD regime being put in place as part of the EMR. Eight renewable electricity projects were offered investment contracts in 2014, allocating the first CfDs through the EMR programme.

TABLE 11: CFD ALLOCATIONS

CfD unit	Technology type	Initial installed capacity estimate for CfD unit (MW)	Initial strike price (£/MWh)
Beatrice Phase 1	Offshore wind	280	140.00
Beatrice Phase 2	Offshore wind	384	140.00
Burbo	Offshore wind	258	150.00
Drax 3rd Conversion Unit (Unit 1)	Biomass conversion	645	100.00
Dudgeon Phase 1	Offshore wind	90	150.00
Dudgeon Phase 2	Offshore wind	210	150.00
Dudgeon Phase 3	Offshore wind	102	150.00
Hornsea Phase 1	Offshore wind	400	140.00
Hornsea Phase 2	Offshore wind	400	140.00
Hornsea Phase 3	Offshore wind	400	140.00
Lynemouth Power Station	Biomass conversion	420	105.00
Teesside	Dedicated biomass with CHP	299	125.00
Walney Phase 1	Offshore wind	330	150.00
Walney Phase 2	Offshore wind	330	150.00

Source: BEIS, based on LCCC data.

83. There have since been two CfD allocation rounds – the first in 2015 and the second in 2017:

- *Allocation round one*: open to all technologies ('established' and 'less established'). For the delivery period spanning 2014/15 to 2018/19 there was a 100MW reserved minimum budget for wave and tidal stream across the RO and the CfD schemes.
- *Allocation round two*: open only to 'less established technologies' (offshore wind, wave, tidal stream, advanced conversion technologies, AD, dedicated biomass with CHP, and geothermal). The ring-fenced budget for wave and tidal stream was not extended for the second round. A temporary 150MW maximum across fuelled technologies was also applied for the second allocation round.

84. Generators sell their electricity into the market in the normal way, and remain active participants in the wholesale electricity market. The CfD pays the difference between the reference price (a measure of the average GB market price for electricity) and the CfD strike price (an estimate of the long-term price needed to bring forward investment in the technology).

85. National Grid is the delivery body for the CfD. Generators initially apply to the delivery body to see if they are eligible to take part in the allocation process. Once qualifying applications have been established, the CfD valuation and allocation process is run. During the valuation and allocation process, the delivery body assesses whether there is a requirement for a competitive auction, based on applications. If the budget is exceeded, a competitive auction is run to ration the budget between applicants. If the applications do not exceed the budget, the applicants would be offered a CfD at the administrative strike price.

86. The cost of CfDs is met by consumers via the Supplier Obligation, a levy on electricity suppliers. The Supplier Obligation is collected by the LCCC, which is responsible for making payments to CfD generators. Each levy period is based on a calendar quarter, with the underlying amounts owed by suppliers over the quarter equal to the CfD payments owed to generators in respect of the quarter

87. The auctions are summarised in the tables below.

TABLE 12: SUMMARY OF AUCTION RESULTS: ALLOCATION ROUND 1

Maximum % Saving on Admin Strike Price for each technology as result of competition

Technology	Admin Strike Price (£/MWh)	Lowest Clearing Price (£/MWh)	Maximum % Saving on Admin Strike Price
Solar PV	120	50	58%
Onshore Wind	95	79.23	17%
EfW CHP	80	80	0%
Offshore Wind	140	114.39	18%
ACT	140	114.39	18%

NOTE - Given there are a number of different admin SP and clearing prices for each technologies, the above numbers are based on the maximum difference between clearing and admin SP

Source: BEIS, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/407465/Breakdown_information_on_CFD_auctions.pdf.

Note: One solar contract has subsequently been terminated.

TABLE 13: SUMMARY OF AUCTION RESULTS: ALLOCATION ROUND 2

(E) % Saving on Administrative Strike Price for each technology as result of competition (2012 prices).

Technology	2021/22 Administrative Strike Price £/MWh	Clearing Price £/MWh	% saving
Advanced Conversion Technologies	125.00	74.75	40%
Dedicated Biomass with CHP	115.00	74.75	35%
Offshore Wind	105.00	74.75	29%

Technology	2022/23 Administrative Strike Price £/MWh	Clearing Price £/MWh	% saving
Advanced Conversion Technologies	115.00	40.00	65%
Dedicated Biomass with CHP	115.00	N/A	N/A
Offshore Wind	100.00	57.50	43%

Source: BEIS, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/643560/CFD_allocation_round_2_outcome_FINAL.pdf.

88. The RO, the ROCs and the FiTs and CfDs are not the only subsidies renewables receive. Analogous to how other subsidy regimes developed in other parts of the economy, notably agriculture, a number of additional supports have been added on a piecemeal basis. These include, but are not limited to, those set out in the box below.

Tax exemptions and other support for low-carbon electricity

Climate Change Levy

Up until 1st August 2015, electricity generation from renewable sources was exempt from the CCL; however, electricity generated from this source is now subject to it. The main rate of CCL is currently £0.00568/kWh supplied.

Source: https://www.gov.uk/government/publications/excise-notice-ccl13-climate-change-levy-reliefs-and-special-treatments-for-taxable-commodities/excise-notice-ccl13-climate-change-levy-reliefs-and-special-treatments-for-taxable-commodities.

Business rates

No exemptions apply to renewable generators. Income from FiTs and other schemes is taken into account when assessing a property's value for business rates.

Source: https://www.gov.uk/introduction-to-business-rates.

Capital allowances

The installation of low-carbon electricity generation is not eligible for any specific Enhanced Allowances, which enable the total capital cost of a given investment to be offset against profits for tax purposes, although renewable heat generation plant such as biomass boilers or heat pumps are eligible. All other low-carbon electricity investments are eligible for standard capital allowances in line with other types of capital spending.

Source: https://www.gov.uk/government/publications/enhanced-capital-allowance-scheme-energy-technology-product-list.

UK Guarantees Scheme

This scheme is open to all infrastructure projects, and underwrites debt used to back particular projects selected by the Infrastructure and Projects Authority. The guarantee is currently available for the Hinkley Point C nuclear project, along with a mix of other energy and non-energy infrastructure projects.

Source: https://www.gov.uk/guidance/uk-guarantees-scheme.

VAT

The installation of small-scale energy-saving materials on residential premises is currently liable for VAT at the reduced rate of 5%, although the supply of those products to the installer is at the standard rate of 20%.

Source: https://www.gov.uk/government/publications/vat-notice-7086-energy-saving-materials/vat-notice-7086-energy-saving-materials.

Third-Party Liability Regime

The UK Guarantees Scheme (UKGS), launched in 2012, supports private investment in UK infrastructure projects. It is available across a wide range of sectors including energy, and provides HM Treasury backing to private sector infrastructure bonds and loans, by issuing guarantees to investors to reduce their risk in return for a commercial fee. The aim of UKGS is to support projects where finance gaps arise, without crowding out commercial finance. The Infrastructure and Projects Authority manages the scheme on behalf of HM Treasury.

Source: BEIS, https://www.gov.uk/guidance/uk-guarantees-scheme.

89. I recommend a government audit of the full costs of these supports and subsidies.

90. What emerges from the above is the sheer complexity of these policy interventions, and how that complexity has been added to as the government has been sucked further into the administration and rule-setting for them. What started out as a simple RO/ROC model was complicated by banding, and then the banding itself got ever-more complex as each banded renewables sought through lobbying further advantages for its particular technology. It is unsurprising that the costs mushroomed, and then that the LCF detailed in section 5 had to be put in place. It is these complex interventions which have caused the high and rising legacy costs; why these mistakes from the past should be ring-fenced into a separate legacy bank; and why these many types of scheme should be brought to a gradual end, once the existing commitments have been met. Reforming them from within is a second-best option, and a temporary step on the path to their abolition as the long-run framework is put in place.

91. Below I recommend the merging of the FiTs and CfDs into the capacity auctions, and abandoning them in the longer term, both as renewables become cost-competitive (once the full cost of carbon is taken into account) and hence mainstream generating technologies, and because they are badly designed. To understand why these reforms would significantly bear down on the cost of energy, while meeting the carbon objectives, the first step is to set out the costs and cost structures which are peculiar to renewables; explain why the FiTs and CfDs as energy price contracts do not solve these; and then show how some elements of these could be brought under the capacity umbrella.

92. The FiTs and CfDs are badly designed simply because they do not reflect the underlying cost structures. Unpacking the costs of renewables starts by distinguishing the various cost characteristics. For biomass, the cost structure is conventional. There is a fuel cost, and in the case of wood pellets, a long supply chain. The cost of the fuel inputs should reflect this complete chain – from the trees and wood collection, pelletisation, drying, and transportation, to the power station (including trucking, shipping, port-handling, delivery, and cooling costs to prevent combustion). These are additional to the costs of the investment in the plant to burn the stuff, and its operating costs. Being conventional, biomass can act as a balancing generator and provide ancillary services, and is not inherently intermittent – as shown in the load factors in the bar chart below. Like fossil fuel plant, it can operate in the energy-only market. Its core problem is whether it receives due recognition for its genuine carbon savings and, until Brexit, its role in meeting the EU Renewables Directive target, and payments for its capacity availability through the capacity auctions. Post-

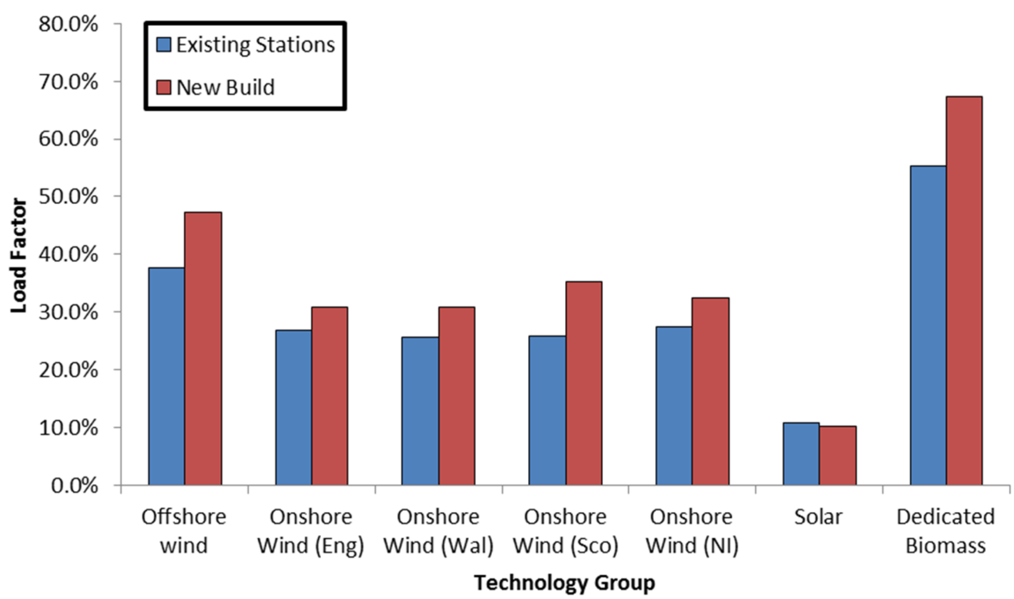
Brexit, biomass is a conventional, except the carbon dimension. It is just wood pellets or other bio-materials instead of coal and gas.

93. The costs of wind generation are largely fixed. A wind farm is a lump of capacity: it requires steel and other material inputs, and the project construction. There are some maintenance costs, larger offshore than onshore. The cost of the fuel input – wind – is zero, but it varies in supply. It is a quintessentially capital-intensive technology; its problems are its upfront fixed and sunk costs, and its benefit is its capacity for reducing carbon emissions. It is intermittent and low-density. Plants are small.

94. Solar costs are similar in structure to wind: a solar installation is also a capital-intensive lump of capacity. There are also system costs from its intermittency, but the predictability of supply is much higher and roughly coincides with the daytime demand peaks. Again, it warrants credit for its low-carbon energy.

95. The marginal cost of production when the wind blows and the sun shines is effectively zero. There is no energy cost. Both are primarily capacity, not energy, investments, and both require capacity returns.

FIGURE 33: LOAD FACTOR ASSUMPTIONS FOR RO SETTING 2018/19 (MAJOR TECHNOLOGIES)



Source: BEIS (2017), RO setting explanatory note: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/648424/Renewables_Obligation_2018_19_FINAL.pdf.

96. Neither wind nor solar currently pays the full costs to the system of its intermittence. They should. (As noted, biomass is not intermittent.) There is much debate about what these system costs are. In one respect, this is a matter of semantics. It can be argued that it is inevitable that there will be costs to a system designed with large centralised generation in mind, but that in moving to a decentralised low-carbon system, the system itself would be better designed for the intermittency, and hence by looking at the existing cost structures, the transition is undermined. It can also be argued that the coming of storage and an active demand side will in any event much reduce intermittency problems.

97. A further argument concerns the ability of the existing systems to absorb intermittent renewables. It is argued that there is enough redundancy in existing systems to absorb some renewables up to around 20%, and only after this level is surpassed are there significant system costs from integration. It can then be argued that above 20% in any event necessitates new and more decentralised systems, coinciding with the coming of storage and demand management, and hence any additional costs should be internalised in system CAPEX and allocated to all forms of generation and not just renewables. The decentralised RSOs I recommend in sections 8 and 11 should aid this integration.

98. Even if the additional costs are recognised, the secondary argument is that these are less than the cost of carbon adjustment that should be applied to the fossil fuels. In effect, the playing field is not level, and therefore these system costs should cancel out in the round and so be ignored.

99. There is merit in each and all of these arguments, but none will make either the system or the carbon costs go away. The optimal solution to these, described below, is a proper cost of carbon and an auction system, which merges the capacity market and the FiTs on a common EFP capacity basis, with the wholesale market and CfDs and other contract forms addressing non-firm energy through bilateral voluntary arrangements. I set these out below, as well as some considerations of how in practice these better outcomes might be approximated.

100. Wind and solar share with nuclear the high fixed and sunk costs, and all of these technologies as a result have a private need for protection of these upfront costs. There is, however, nothing unique about this sort of cost structure. Whether these should be provided by the market, and what form they should take, will be dealt with below. Nuclear also has near zero marginal costs. But unlike wind and solar, it is always on, except for planned maintenance and unanticipated outages.

101. Nuclear has the added problem that its time horizon is very long – perhaps 60 years. Unlike wind and solar, it is very exposed to technological progress and has as a result a much greater risk of economic stranding. As already noted, it also has the risk of political stranding, if electorates decide – as in Germany – to exit. There are risks of catastrophe, and long-term waste-management issues. This combination of special characteristics means that nuclear must always be a societal and political choice, and the cost of energy issue is about ensuring that it is delivered, if government so decides, at least cost. The UK has only one new nuclear project currently under way, and the economics and the structure of its contract are explicitly outside the Terms of Reference for this review. For future nuclear projects, the general principles set out below, including firm power bidding to cover the uncertainty about the timing of when the plant will begin to operate, a price of carbon, and the securitisation after project completion, apply as well as to wind and solar. I recommend a more efficient contract structure.

102. In summary, the various cost characteristics suggest that, with the exception of biomass, renewables have two fundamental characteristics:

- large upfront sunk and fixed costs which require *ex ante* contracts or other supports to share the risk;
- low-carbon, which needs to be rewarded.

103. To these may be added:

- R&D, innovation and renewables' immaturity.

104. The key question is whether the FiTs and CfDs are a good answer to these cost characteristics and externalities. The answer is no. There is no good reason to assume that a fixed-price contract for the electricity generated, tied to a CfD, backed by government, is a least-cost way of meeting the carbon objectives, and it is not even the best answer to meeting the EU Renewables Directive.

How to reduce the costs of renewables

105. The first-best answer is to fix the market failures, and then to integrate renewables into the mainstream of the electricity markets. The carbon price should be internalised, the other externalities internalised, and the sunk and fixed costs should be securitised, once the project is completed. There are therefore two obvious and complementary ways forward to reduce the costs of energy while meeting the carbon budgets:

- the development of a carbon price;
- the creation of a single unified capacity auction on an EFP basis.

106. In theory, the two together meet the two overarching objectives. These two policy instruments address the two separate market failures – on carbon, and on security of supply. There would be no need for further FiTs and low-carbon CfDs. If, however, there is a second-best continuation of contracts specifically for renewables and nuclear because the carbon price is too low, then there are much better ways of designing these contracts. At the end of this section I set out how this second-best approach might be taken.

107. There remains a need to support R&D and possibly the need to help with innovation on the basis of R&D as part of an overall industrial policy. Below I recommend how to address these particular market failures.

(i) The carbon price

108. The first-best solution to the carbon externality is to force emitters to pay the full cost of their activities. Farmers releasing carbon from soils, drivers of petrol and diesel vehicles, and industry and power stations should all pay the social cost of carbon (SCC). This in theory internalises the externalities, and provided that the carbon targets set are optimal, they will be met accordingly. The market sorts out the cheapest ways of reducing carbon. The SCC is not necessarily the same as the carbon price necessary to meet the carbon budgets and the CCA 2050 target. The two are equivalent only if the CCA target is itself optimal – which it almost certainly is not. The box below sets out some numbers.

THE SOCIAL COST OF CARBON

The government's current Green Book carbon values are intended to be 'Target-Consistent'.[1] This means the values are based on the marginal cost of meeting a given emissions reduction target. The current values are based on three targets:

- the global ambition to limit global surface warming by 2°C by the end of the century;
- the overall emissions cap under the EU Emissions Trading System (EU ETS);
- the UK's own near-term target for emissions not covered the EU ETS.

The current values are set out below.

Note: [1] Details on the methodology can be found at: https://www.gov.uk/government/publications/carbon-valuation-in-uk-policy-appraisal-a-revised-approach.

TABLE 14: CARBON VALUES AND SENSITIVITIES 2010–2100, 2016 £/TCO2E

	Traded			Non-traded		
	Low	Central	High	Low	Central	High
2015	5	5	5	31	62	92
2020	0	5	9	33	66	100
2030	39	77	116	39	77	116
2040	75	149	224	75	149	224
2050	111	221	332	111	221	332
2060	132	294	456	133	295	457
2070	133	333	532	133	333	533
2080	118	338	558	118	338	558
2090	97	323	549	97	324	550
2100	74	296	518	74	297	519

COMPARISON WITH OTHER COUNTRIES

Broadly, countries use one of four methodologies. (i) is the most common:

i) damage cost estimated (social cost of carbon);
ii) based on current policy (eg, tax rate for petrol);
iii) target-consistent approach;
iv) projection of future carbon market prices.

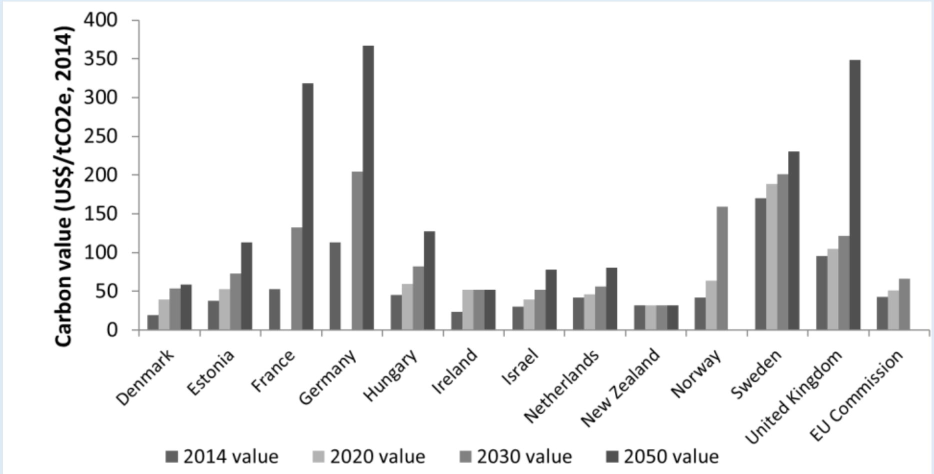
The USA uses a social cost of carbon methodology and varying discount rates to generate a range. This was first introduced in 2010 and revised in 2015 to take account of the latest climate science, resulting in a significant uplift of on average more than 50%. Canada applies a similar methodology, also updated in 2015.

TABLE 15: CARBON COSTS – CANADA

Units	2015	2030	2050
C$ (2012) /tCO_2	40 (high:161)	55 (high:236)	75 (high:320)

Source: http://ec.gc.ca/cc/default.asp?lang=En&n=BE705779-1

FIGURE 34: OTHER INTERNATIONAL CARBON VALUES



Source: *OECD Environment Working Papers*, No. 92 http://dx.doi.org/10.1787/5jrs8st3ngvh-en.

The graph above shows carbon values used in transport investment appraisal as reported for the 2014 OECD survey. Countries may have updated values since and are subject to exchange rate variations.

Source: BEIS.

109. While the whole point of using a market mechanism is that government and regulators do not know the cheapest route, it is possible to hazard an informed guess as to what that path would have been so far. A carbon price set at the SCC level would almost certainly have induced first a switch from coal to gas over the period since the RO came into being. Large carbon reductions could have been made at much lower costs.

110. In fact, what happened in the UK, and indeed also in Germany (and to an even greater extent), was that the coal-burn held its own, and at times actually increased. The UK at least resisted the plans to build the Kingsnorth coal power station in 2004, while Germany has built 13GW of new coal capacity over the period since 2000.

111. Rather than starting with the cheapest option first, the UK started with some of the most expensive. In large measure it was forced to do so by the EU Renewables Directive. In a number of respects it then considered some even more expensive options. The cost of energy has correspondingly been significantly higher than it would otherwise have been.

112. In section 10 I set out the case for harmonising this price of carbon, and in the process considering reforms to the general energy and carbon tax regime.

113. As experience is gained, the carbon price can be varied to hit the carbon budgets. This is a key role for government, and one option is for the CCC to advise the government on how it should be revised, analogous to the way the Monetary Policy Committee looks at the interest rate necessary to meet the inflation target. It would, however, not be appropriate for the CCC to set the price – that should be left to the government.

(ii) The single equivalent firm power capacity auction

114. The second way in which renewables policies lead to higher costs of energy is the different treatment of different technologies and the exemption from the system costs caused by intermittency.

115. The first-best solution to this problem is to integrate the FiTs and low-carbon CfDs into the capacity markets, and make all technologies bid on an EFP basis. This directly confronts those that cause intermittency costs with the costs they cause, just as a carbon price confronts those that emit carbon with the costs they cause.

116. This would be a radical change, but it would have many advantages. These include:

- establishing via the market the full costs of subsidies;
- incentivising the secondary markets in flexibility, back-up supplies, storage, and other ways to manage the intermittency as part of the broader energy-only wholesale market;
- cutting away the 'picking winners' elements and associated lobbying and capture;
- radically reducing and simplifying the multiple policy interventions and regulations.

117. The auction would be on an *equivalent* basis. This means that the de-rated contribution of intermittent capacity is taken into account. The system is typically better off with intermittent capacity than without it – wind farms, for example, can make a contribution to overall security of supply. The EFP of wind is the average contribution of wind power to the de-rated margin. It is the quantity of firm capacity (ie, always available) required to replace the wind generation on the system to give the same level of security of supply, as measured by loss of load expectation (LOLE). It varies with the proportion of wind power on the system and with regard to the generation and demand assumptions for a particular scenario and sensitivity. The LOLE becomes a crucial element in then calculating the desired margin which should be given as guidance to the NSO by the government. The key is the extent to which intermittent generation is or is not correlated to the rest of the generation portfolio characteristics.

118. An individual generator whose availability is uncorrelated with market tightness – for example, if it has only idiosyncratic outages – gets a de-rating by its average availability factor. When wind starts to dominate the system, and wind availability is thus strongly negatively correlated with supply shortage, it gets a de-rating below its average load factor.

119. For example, the EFP may be around 16% for wind today, substantially below its average load factor of around 27%, but still much higher than zero, despite it being quite likely that wind output is very close to zero at certain times.

120. It is especially in the latter sense that the relevant EFP is distinctly not the power/capacity that is 'almost firm', but it is the capacity that is on average similarly helpful as firm (ie, always on) capacity. It has the somewhat slightly surprising implication that a plant that is at any time randomly on or off 50% of the time is allocated a firm capacity factor of almost exactly 50%.

121. In capacity auctions, capacity from each type of generator should be de-rated by an EFP de-rating factor of between 0 and 1, indicating the expected contribution of the generator in all security of supply-relevant periods. The relevant periods are those where there is not (or is just about) enough capacity to meet demand.

122. EFP is not a radically new concept, and is already used by National Grid and Ofgem. National Grid had no reason to auction wind in the capacity market, for example, because it is already given the separate subsidies, but it does deduct the EFP contribution by existing wind from the capacity auction procurement level. In the absence of FiTs, bidding wind becomes relevant in the capacity auctions.

123. EFP for storage and batteries raises some additional issues. Even if available nearly 100% of time theoretically, once we rely on batteries for many GW of supply in tight periods, at some point they start to be unable to sustain their production for long enough to avoid black-outs – ie, if the margin of supply net of batteries is negative for overly long stretches, batteries start to empty, lowering their EFP. So like wind, their EFP decreases according to their storage capacity.

124. What would be revealed in EFP auctions is that different renewables have very different system costs. Solar would have lower intermittency costs than wind, and both would have higher costs than biomass. Solar would need to address the problem of night-time hours and longer and darker periods during winter, whereas wind would have to address much more varied supply intermittency in order to achieve higher returns from the EFP auctions.

125. These renewables would then have a strong incentive to do deals with those that offer back-up, to engage with customers on demand-side management, and develop storage options and other innovative ways of managing the variances they create through the market or by direct investments. This increases their value in EFP auctions, as their de-rating factor improves. It is much more likely that an active energy management market would develop with these incentives from a firm power auction, rather than if it is left to the system operators to determine. It would be a major spur to the energy services businesses.

126. The obvious objection is that an EFP auction would take no account of carbon. It would achieve the security of supply objectives and it would reduce costs, but at the expense of failing to meet the carbon budgets.

127. There are two responses. First, if as described above the price of carbon is set at that level necessary to meet the carbon target, the cost of carbon would have been internalised and the target would be met. This is the first-best outcome: a price of carbon and an EFP auction, meeting simultaneously the carbon and security of supply objectives. Such a system would be simple, market-based and cost-efficient. The government could then withdraw substantively from its many interventions identified in section 4.

128. The reason why the carbon price may not be set at the right level is because of political constraints. Politicians may not want to confront the polluters with their true costs, especially as they are voters too. They would also come up against the full force of lobbying, for exposing the true cost of renewables would create some clear and obvious losers.

129. If, for lobbying and political reasons, government does not want to choose the most cost-effective solution, then the unified auction for EFP will need to take account of the carbon budget constraints. This can be done in a two-stage auction, or a single scored auction. At stage one everyone bids on a common basis. These bids reveal a lot of information. The auctioneer can then look at the supply curve revealed in the bidding and see whether it would meet the carbon budget. If not, then a second-stage constrained firm power auction can be held. This could be on a repeated-bid basis until the answer tracks the carbon budget. Alternatively, all the relevant information could be requested in the single scored auction. This has the advantage of being deep and liquid, whereas the second stage auction would be more limited.

130. The above recommendation would hit new and emerging technologies. The problem here is best seen as an R&D and innovation one, and for this R&D and innovation support mechanisms are

required. The principles are set out in section 6. Looking at the current embedding of supports within the FiTs, and a number of funds and interventions on batteries, EVs, small modular nuclear, and so on, it is far from clear what the overarching logic is, or the extent to which the subsidies are driven by lobbying rather than value-for-money consideration.

Second-best solutions and a continuation of direct contracts for renewables

131. Government may not be willing to opt for a first-best policy – or at least not immediately. There are as noted enormous vested interests in the existing policy architecture, and in any event, there would have to be a transition period, which in turn might be shaped by the speed with which renewables become fully cost-competitive. Direct contracts for specific renewables are very much a second-best policy option. If such second-best contracting persists, it can be achieved at lower cost than at present. For these reasons I recommend a series of transitional measures to improve the FiTs and CfDs once existing commitments have been met.

132. A lower-cost, second-best approach should reflect the structure and phases of renewables and nuclear projects identified above, and their associated cost structures. There are three: the initial project development; the operation of the completed plant; and decommissioning. These three stages of projects have very different risks and cost of capital.

133. In phase one, there is considerable equity risk associated with the delivery of the plant on time and on budget. In some cases, this is increasingly well known. For example, wind installations can be partly contracted out to construction companies specialising in these sorts of activities, as can be done in the case of gas and coal plant. In other cases, like nuclear, there are overall project risks which are hard to call in advance, and can and usually do result in project overruns and higher costs. These costs are mostly under the control of management, and hence are genuine equity risks. Exogenous cost shocks, caused, for example, in nuclear by changes in regulations, can be mitigated by specific agreements.

134. The equity cost of capital for this initial phase is typically similar to those of construction companies, and is likely to be 10–20%.

135. In phase two, the operational stage, there are two risks: that the plant fails to work as intended; and that the market price of the energy generated falls short of expectation. To this can be added a third: time-inconsistency and *ex post* regulatory and government interventions.

136. Operational risk is of a different order of magnitude to construction risk. Typically, the equipment manufacturers give performance guarantees. If the output is sold forward, then the asset looks more like a debt-financed RAB, familiar to the regulated utilities, and can be securitised. That indeed is what infrastructure funds and specialist businesses do. They 'buy' completed projects and then move to a lower, largely debt-backed cost of capital.

137. In the case of FiTs and CfDs, the value of the completed project in phase 2 is easier to estimate than at the outset. It is the discounted value of the FiT and CfD contract, net of the operations costs. As a broad indication of the ball-park numbers, in Germany these projects can be securitised at a cost of capital of as low as 3%. In the UK the rate can be 6–10%. The difference between these two numbers is very large, and is also relevant for the options for securitising the legacy contracts discussed in section 5. The precise numbers will vary from project to project and over time.

138. In phase three, the decommissioning costs vary greatly across technologies. In the case of nuclear these loom large, as reflected in the costs borne by BEIS now for the UK's nuclear legacy. In the case of solar and wind, they are likely to be very small relative to the project value as a whole. But even in the case of nuclear decommissioning, these are incurred long after the project is constructed, and at any positive discount rate, make very little difference to the project finances at the outset. They can be handled by making a charge against current revenues to create a 'pension fund' for liabilities, and the fund can then grow over time.

139. Roughly, the cost of capital for phase one is the cost of equity; for phase two it is largely the cost of debt; and for phase three it is incorporated in the operating costs through a provision. It is immediately apparent that the optimal contract for a renewables or a nuclear project is not a single fixed price for the energy generated over the lifetime of the project, and that this mismatch is likely to give rise to a substantial pay-out to investors when the project comes on stream in phase two. This indeed is what has happened: the 'buying' and 'securitising' has been a profitable refinancing activity. The reason this is a matter of concern is that these gains currently accrue mainly to investors, not customers.

140. The common feature of these examples is that they separate out the equity risks in the early construction phase. I recommend that government conduct a review of the alternative contracting models and assess their impacts on the cost of capital, and in particular compare these with the costs of capital for RABs in the utilities.

141. An additional reason for FiT and low-carbon CfD contracts has been that, even when completed, these projects will continue to be out of the market. With a common carbon price set at the level necessary to meet the carbon budgets, this would not matter: the public interest is met by achieving the targets, not supporting specific technologies. Yet another argument is that the FiTs and low-carbon CfDs are an immature technology subsidy, but as argued above, this is better achieved through a clear and specific R&D policy. The case for *mass* deployment in the future of new and infant renewables technologies is hard to make, and for offshore wind, probably the only credible case, this deployment has now happened. As the costs of renewables continue to fall, it is only the carbon price that is needed to ensure a level playing field as renewables become the new conventionals.

MAIN FINDINGS AND RECOMMENDATIONS

On the wholesale markets

- NETA was a mistake, and in particular the loss of the compulsion to sell power through the wholesale market and the abolition of a capacity mechanism.
- Market power is nevertheless limited by the combination of the capacity market and the excess capacity margin it creates, and zero marginal cost renewables and nuclear.
- The wholesale market is already becoming less economically significant as a way of recovering the full costs of electricity generation.

On the capacity market

- The capacity market is the prime vehicle for ensuring security of supply.
- The initial capacity auctions have been broadly successful.
- The system operator should be separated from National Grid as a public interest body, the NSO.
- The NSO should have the duty to ensure adequate capacity and discretion in its delivery.
- The government should set the desired capacity margin, taking account of all the new DSR and storage options, through an annual statement to Parliament.
- The government should give guidance to the NSO on how to handle the uncertainty around the 13GW potential nuclear investment in the capacity auctions.

On the FiTs, low-carbon CfDs, and the unified EFP auction

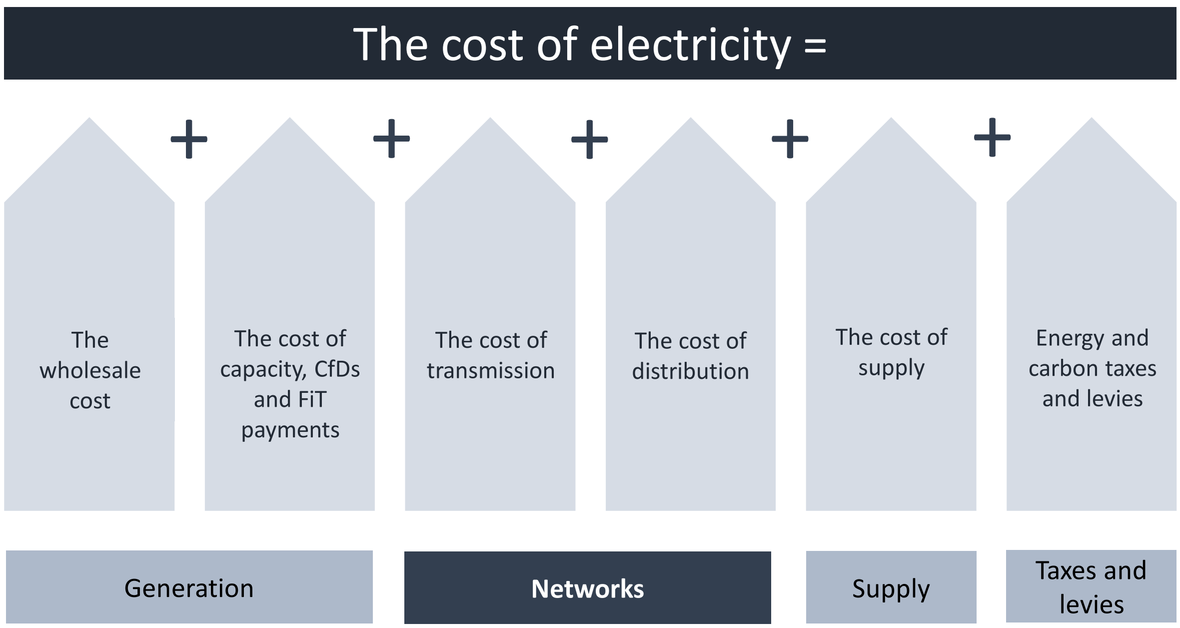
- The FiTs and low-carbon CfDs and the capacity markets should be merged into a unified equivalent firm power market.
- EFP contracts should be auctioned by the NSO on an ongoing basis, with the NSO responsible for determining the timing, length of contracts, and amounts of capacity auctioned, subject to government guidance on the overall capacity margins for security of supply purposes.
- The EFP auctions should be primarily based on price, but the allocation of contracts should take account of the carbon impacts in the absence of a proper carbon price necessary to meet the CCA and carbon budget targets.

- The government to issue guidelines for the criteria for scoring bids.
- The NSO should examine the bids, and then take account of the carbon budget constraints, and make awards of contracts which are least-cost, subject to the carbon constraints.
- In the absence of a proper carbon price, where the gaps between fossil fuel and low-carbon bids are large, the NSO should consult with the CCC to identify whether there are greater value-for-money savings in carbon which could be made in other sectors, notably transport, buildings and agriculture.
- Over time, the RSOs proposed in sections 8 and 11 should take on some of these auctioning functions in conjunction with the NSO.
- The market in the back-up for intermittency to assist the renewables should be further encouraged, so that the intermittency can be met through a portfolio of contracts. This market should further bring into play demand responses, storage and back-up generation. These suppliers of services will then be able to match up with the expected intermittency of the renewables generators. The renewables can then bid for less de-rated EFP contracts.
- Renewables will remain able to sell non-firm power, and to enter into long-term contracts with purchasers of non-firm power – for example, companies involved in vehicle-charging and energy services businesses.
- As with all such contractual arrangements, provision will need to be made for default and other failures, and these responsibilities should lie with the NSO and RSOs, as recommended in section 11.
- If the above first-best approach is rejected, and after all current commitments have been met in full, the FiTs and low-carbon CfDs should be restructured according to their three phases, with capital support and tax concessions in respect of the project development and construction phases, and then at completion a refinancing arrangement put in place. Long-term, fixed-priced energy contracts for the whole project life, or a substantial period of its life, should eventually be abolished.
- A closure date for the FiTs and low-carbon CfDs should be set.

8. Networks

This section addresses:

- **the contribution of transmission and distribution costs to rising energy bills**
- **the mistakes in the last periodic reviews and the case for and against intervention before 2021–23**
- **why there should be no more periodic reviews in the longer term**
- **the role of the NSO and the RSOs in bringing competitive auctions into the network services and taking on some licence functions**



1. Transmission and distribution costs made up 28% of the typical household bill in 2016, which is determined by Ofgem through price caps set in periodic reviews.

2. The early development of price caps had the great merit of simplicity, and they were applied to an industry where there had been little technical progress over decades. At privatisation, little further technical progress was expected. The job of the regulator was to incentivise the privatised companies to maximise profits by minimising costs, and to do this the early regulatory regime offered a simple fixed-priced, fixed-period contract. This approach can be called the Littlechild model, after the inventor of RPI (Retail Price Index) – X regulation, and the first Director General of OFFER (Office of Electricity Regulation).

3. Under the nationalised framework, the networks were financed on a pay-as-you-go-basis. Current OPEX and CAPEX were paid for out of current bills. There was little or no direct borrowing. Privatisation changed this, and in particular created private balance sheets so that borrowing could finance current CAPEX and customers would pay-when-delivered.

4. The early fixed-priced contracts regulation proved to be weak, and it facilitated significant financial engineering on the part of the companies. It also encouraged a wave of takeovers. It was never envisaged at privatisation that the balance sheets would be used to arbitrage the cost of equity and debt, and that a principal source of profit for the companies would come from financial engineering and falling interest rates. This matters now, as the companies face significant investment against relatively highly geared balance sheets.

5. The first test came in 1994, just four years after privatisation. Trafalgar House bid £11 per share for Northern Electric, the shares having been sold for £2.40 each in 1990. In response, Northern Electric in effect mortgaged its assets, and paid out around £5 cash for every share from the money it borrowed against its assets. Notwithstanding this payment, the company was then sold for about £7 per share a short while later. The regulatory response was remarkably passive. This was a significant mistake.

6. Some 25 years after privatisation, almost all the distribution companies have changed hands, sometimes many times, and the electricity grid merged with the gas transmission network (Transco, which itself had been demerged for British Gas) to form National Grid. They all geared up their balance sheets, and most practically exhausted them. The cost of energy going forward is therefore going to be driven back towards pay-as-you-go, unless they are forced to repair the balance sheets through equity injections. The money has been taken out in dividends, special dividends and share buy-backs. Putting some of it back would be a painful experience for some, but customers are protected by the Special Administration process that kicks in in the event of default.

7. The periodic review process has allowed this to happen. Indeed, in practice, it has positively encouraged it. Regulators have played catch-up in response to what has happened. Current regulatory approaches are not fit for purpose for the existing activities, and they are inadequate for the challenges ahead of digitalisation and the emerging impacts on the energy sector described in section 6.

8. So fundamental are these technical changes that they raise structural questions about the regulatory licences as well as issues about the future of periodic reviews.

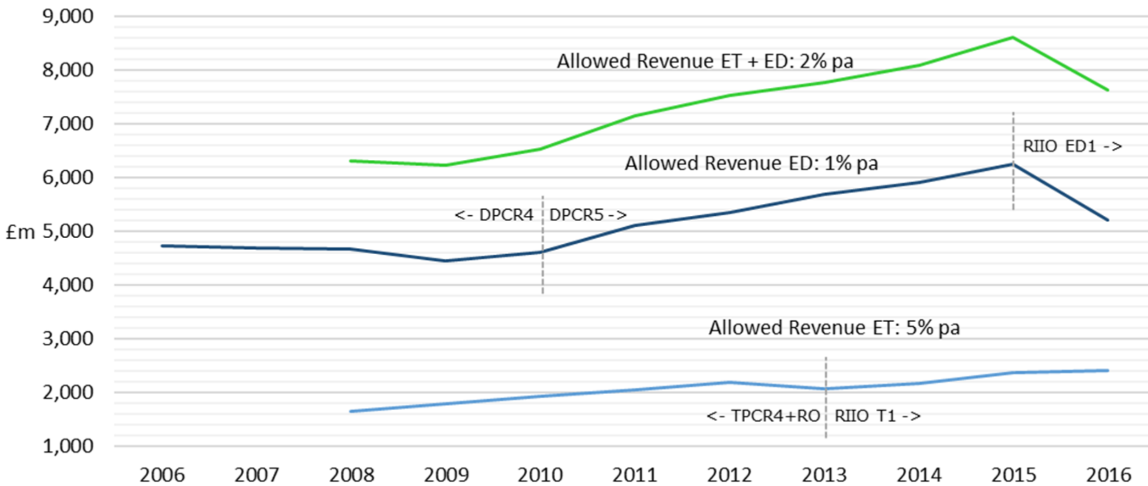
What to do about the current periodic regulation

9. Ofgem reviewed RPI – X regulation in 2010, and concluded that a new regime would be needed. This was called RIIO (Revenue = Incentives + Innovation + Outputs), and it had two basic principles: that the periods should be extended out to eight years; and that regulation should focus on outputs and incentives, over and above those created by a fixed-price cap in the Littlechild model. There are three price controls; T1 for transmission; GD1 for gas distribution; and ED1 for electricity distribution. Given that this review concerns electricity, I focus on the transmission and distribution price caps. I also concentrate on National Grid, although my analysis and recommendations can also be applied to the Scottish transmission companies.

10. These two principles have been undermined by events. The returns to National Grid (the main transmission company) and to the DNOs have exceeded the expectations of Ofgem by a considerable margin already as experience has diverged from projections. The lengthening of the period has not worked well in a context of rapid technological progress, as described in section 6. In order to maximise the incentives and the output focus, the RIIO approach provided only for a possible interim review after four years, and only for a specified narrow number of items. Given that periodic reviews take around two years to construct, by the start of the next decade the networks will be working on the basis of assumptions made at the beginning of this decade.

11. A great deal has already changed against expectations. The chart below shows the total allowed revenues from the current price controls.

FIGURE 35: ELECTRICITY TRANSMISSION AND ELECTRICITY DISTRIBUTION ALLOWED REVENUES (2016/17 PRICES)



Source: Ofgem.

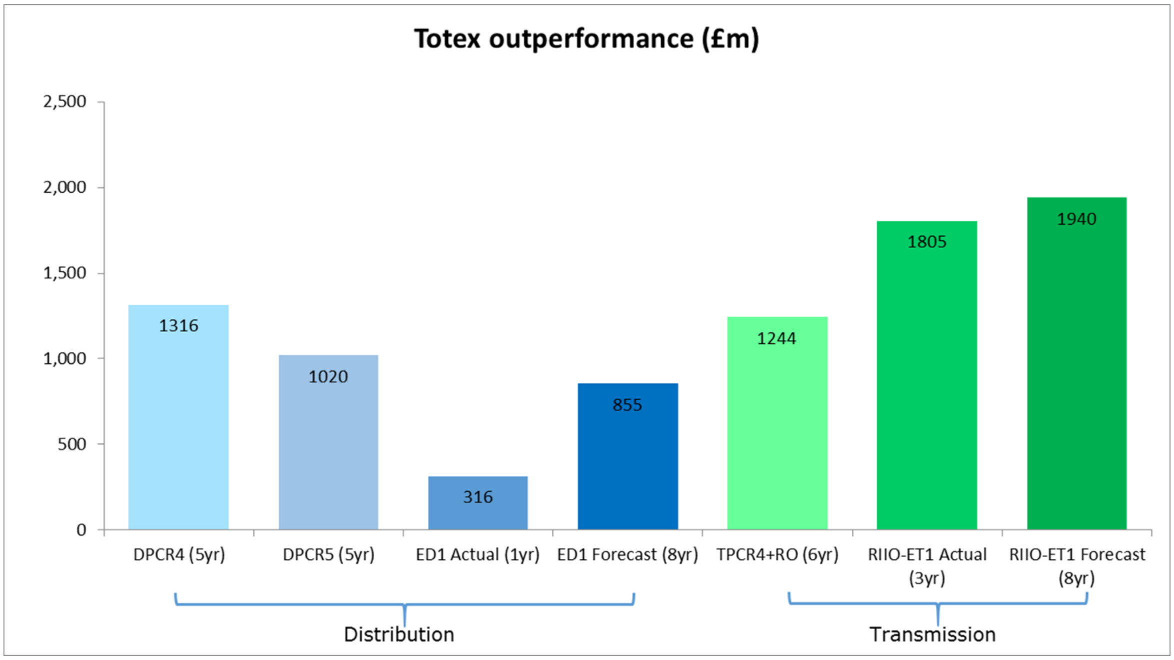
Notes: ET, electricity transmission; ED, electricity distribution. The figures presented for TPCR4+RO and RIIO-ET1 include SPT, SHET and NGET in its role as transmission operator.

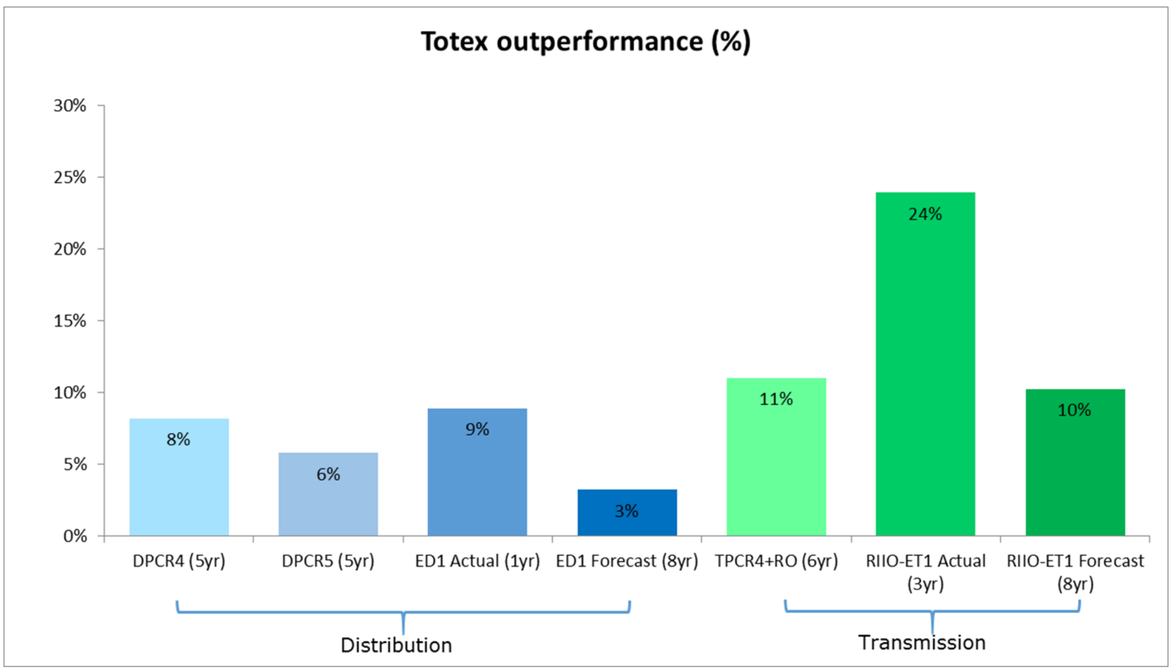
12. Electricity distribution allowed revenues have increased in real terms by an average of 1% per annum between 2006 and 2016. Electricity transmission companies' allowed revenues have increased by an average of 4.9% per annum from 2008 to 2016.[1] The need to reinforce the electricity transmission system to accommodate increased levels of renewable generation has been a key driver for these significant increases in electricity transmission revenues.

13. The charts below compare the total price control allowances with the actual spend of the companies. For the current price controls (RIIO-ED1 and RIIO-T1), actual performance to date is presented, as well as forecast performance for the entire eight-year period. These are for total expenditure (TOTEX), which combines CAPEX and OPEX.

[1] Data provided by Ofgem.

FIGURE 36: TOTEX OUTPERFORMANCE (£ MILLION AND %)





Source: Ofgem, Electricity Distribution annual report 2015-16, Electricity Transmission annual report 2015-16.

14. Electricity distribution has tended to see lower levels of outperformance than electricity transmission. There may be several explanations for this, including there being fewer comparators in electricity transmission, making setting these controls more challenging.

15. For both of the current price controls, the companies are forecasting lower levels of outperformance in the remaining years. This is not uncommon as the companies tend to backload some of their investment programmes.

16. All electricity transmission owner businesses are currently forecasting outperformance against the total RIIO-ET1 allowances. Taken together, the transmission companies currently expect to underspend by 10%. The T1 forecast outperformance is below the level of underspend across the previous six-year period (11%).

17. Ofgem’s analysis of the key drivers of TOTEX outperformance is set out in the box below.

OFGEM'S ANALYSIS OF OUTPERFORMANCE

Outperformance during the previous electricity distribution price controls (DPCR4 and DPCR5) is largely explained by demand falling and fewer demand connections. In DPCR5, companies also outperformed allowances by using greater volumes of refurbishment rather than replacement to manage poorer condition assets, by improving efficiency, and because of falling input prices due to economic conditions.

Distribution companies are forecast to outperform their RIIO-ED1 TOTEX allowances by underspending in asset replacement and refurbishment by £400 million (7%), and in load-related expenditure by £400 million, due to demand falling away. These reductions in load-related expenditure are largely due to the load requirements not materialising as expected; uncertainty on the take-up of low-carbon technologies; and the greater impact of energy efficiency measures.

For electricity transmission, outperformance during TPCR4 and the roll-over year was largely explained by load (ie, demand) falling away through the period (SHET spent 85% of its load-related allowance; NGET spent 76%; and SPT only 44%). The companies also highlighted delays associated with planning consent as a major driver of spend. NGET and SPT also spent less than the allowances in the non-load-related category (10% and 24%, respectively) due to decisions to refurbish rather than replace assets and deferral of maintenance. SHET, in contrast, underperformed in this cost category (13%).

A range of factors drives the forecast level of outperformance across RIIO-ET1 by each of the transmission operator businesses. The majority of the outperformance lies with NGET.

NGET considers that refinements to its asset intervention plans more efficiently target replacement of higher-risk components. This technique is estimated to deliver around £170 million of savings compared with allowances. NGET expects changes in procurement strategies and general improvements to ways of working to increase volume delivery and reduce costs in excess of around £500 million.

SPT is forecast to spend 95% of its RIIO-T1 TOTEX allowances, while SHET forecasts spending 94% of RIIO-T1 TOTEX allowance.

When Ofgem set RIIO-ET1, it provided allowances to cover increases in input prices (relative to RPI growth). Due to macroeconomic conditions, actual input prices (eg, labour and materials) have increased much more slowly than expected. In Ofgem's 2016 annual report it estimated that the cumulative difference for all licensees could be approximately £1.5 billion across RIIO-ET1.

Source: Ofgem.

18. The above factors indicate that two played a considerable role, and both of these are to an extent outside the control of the companies. Lower demand is not within management control, and Ofgem's assumption about input costs was simply, if understandably, wrong.

19. Ofgem forecasts the projected outperformance in the RIIO price controls to impact the notional return on regulated equity compared with the baseline returns of 6% and 7% in ED1 and T1,

respectively. This measure also builds in the effect of the price control incentives, which reward/penalise companies based on their performance.

20. Based on DNOs' forecast performance for RIIO-ED1 and RIIO-ET1, Ofgem has calculated return on regulatory equity (RoRE) ranges from 7.2% to 11.6%, and 9.4% to 11.5%, respectively. The weighted average of the DNOs is 9%, and for the transmission operators it is 10.2%. This estimate depends on current forecasts and future delivery of outputs, and may change during the remaining years of the price controls.

21. RoRE presents a comparative measure of annual equity returns. It is presented on a post-tax basis – that is, after allowing for the impact of corporation tax. Its estimation includes the use of certain regulatory assumptions, such as the assumed gearing ratio of the companies, to ensure comparability across the sector. To eliminate phasing impacts over the course of the price control, Ofgem uses a mix of actual and forecast performance to calculate eight-year average returns. These returns may not equal the actual returns seen by shareholders.

TABLE 16: OFGEM'S CALCULATION OF THE RETURN ON REGULATORY EQUITY (RIIO EIGHT-YEAR)

Electricity Transmission

Licensee	RORE
NGET (exc. SO)	9.4%
SHE	11.5%
SPT	9.8%
Weighted Avg.	10.2%

Electricity Distribution

Licensee	RORE
ENWL	9.2%
NPgN	7.6%
NPgY	8.5%
WMID	7.8%
EMID	8.6%
SWALES	8.6%
SWEST	7.5%
LPN	11.6%
SPN	11.5%
EPN	11.4%
SPD	7.3%
SPMW	7.2%
SSEH	8.9%
SSES	9.7%
Weighted Avg.	9.0%

Source: Ofgem, Electricity Distribution annual report 2015-16, Electricity Transmission annual report 2015-16.

22. The higher returns are reflected in company valuations. These are harder to estimate since none of the DNOs is quoted as a separate entity, and National Grid's share price reflects its North American business, its gas as well as electricity activities, and some of its new business developments. SSE and

ScottishPower combines generation and renewables, with networks and supply. In ScottishPower's case, it is also an international business.

23. A proxy for the outperformance is given by the valuations infrastructure funds report to their investors, and in the premia to RABs in takeovers. I recommend that, where possible, Ofgem keep a register of these evaluations reported in these reports, and publishes this on its website, alongside a disaggregation for the quoted companies.

24. The table below summarises mergers and acquisitions in electricity transmission and distribution. It may not be exhaustive.

TABLE 17: POST-PRIVATISATION MERGERS AND ACQUISITIONS IN TRANSMISSION AND DISTRIBUTION

	Transmission	Distribution
1986	All gas assets transferred to **British Gas plc**.	
1990	**National Grid Company (NGC)** becomes the owner and system operator of the electricity transmission network in England and Wales. **ScottishPower** and **Scottish Hydro-Electric** become the owners and system operators of different parts of the electricity transmission system in Scotland.	**Regional Electricity Companies** – jointly owned NGC. Integrated distributors and suppliers. Shortly after privatisation, distribution and supply businesses separated, and Regional Electricity Companies defined as **Public Electricity Suppliers (PESs)**: – Midlands Electricity – Yorkshire Electricity – Northern Electric – Eastern Electric – Norweb – Scottish Hydro-Electric – Southern Electric – SWALEC – London Electricity – SWEB – ScottishPower – Manweb – East Midlands Electricity – SEEBOARD
1995	National Grid is floated on the stock market as an independent company.	**North West Water** acquires **Norweb** and creates **United Utilities**. **SWEB** acquired by **Southern Company**. **Manweb** acquired by **ScottishPower**.
1996		**CE Electric** (a subsidiary of the US CalEnergy) acquires **Northern Electric**. **Midlands Electricity** acquired jointly by **GPU and Cinergy**. **Dominion Resources** acquire **East Midlands Electricity**. **Welsh Water** acquires **SWALEC**, rebranding as **Hyder**. **SEEBOARD** is taken over by **Central and South West Corporation (CSW)**.
1997	**Energis** is demerged from National Grid. **Centrica** is demerged from British Gas. **Transco** remains with BG plc.	**American Electric Power** acquires **Yorkshire Electricity**.
1998		Eastern Electricity becomes **TXU Energy**. **PowerGen** acquires **East Midlands Electricity** from **Dominion Resources.**
	Scottish Hydro-Electric and **Southern Electric** merge to become **Scottish & Southern Energy**. Vertical integration is maintained in the new structure.	

1999		Distribution and supply are legally separated. PESs replaced with **DNOs**. **TXU** merged with **London Electricity** to form **24seven Utility Services**. **Cinergy** sells its share in **Midlands Electricity** to **GPU**. **Hyder** sells the retail gas and electricity businesses under **SWALEC** to **British Energy**. The electricity distribution business is renamed **Infralec**. **Western Power Distribution** acquires **SWEB**, splits distribution and supply.
2000	**Transco** is demerged from **British Gas (BG) Group** and renamed **Lattice Group**.	**GPU** announces merger with **FirstEnergy**. **Hyder** acquired by **Western Power Distribution** and **Infralec** is rebranded under the **Western Power Distribution** name. **CSW** merges with **American Electric Power (AEP)** (new company is called **AEP**).
2001		**Innogy** acquires **Yorkshire Electricity** from **AEP**. **CE Electric** (owned by **Mid-American**) takes ownership of **Yorkshire Electricity** from **AEP** (exchanging Northern Electric Supply business). Rebrands as **CE Electric UK**. **Utilicorp United** acquires **Midlands Electricity** (First Energy acquires GPU shortly after).
2002	National Grid and **Lattice** merge to form **National Grid Transco**.	**London Electricity** (LE Group) acquires **SEEBOARD.** 24seven Utility Services (TXU and London Electricity) becomes **EDF Energy Networks.** **Utilicorp** is renamed **Aquila**. **Aquila** purchases share of holding company for **Midlands Electricity**.
2003		**Powergen** acquires **Midlands Electricity**.
2004	National Grid Transco acquires **CrownCastle UK**.	**Powergen** rebranded as **E.ON UK**. **E.ON** merges **Midlands Electricity** with **East Midlands Electricity** under the name **Central Networks**.
2005	National Grid Transco plc is **renamed National Grid plc**. National Grid takes on electricity system operator responsibilities in Scotland (ScottishPower and Scottish & Southern Electric remain owners of the transmission network).	National Grid Transco sells four of its eight gas transmission networks: – Scotland and South of England are sold to Scotia Gas Networks. – North of England is sold to Northern Gas Networks – Wales and the West is sold to Wales and West Utilities. North West, West Midlands, East of England and London are retained by National Grid.

2007		**United Utilities** sells **Norweb** to **Electricity North West Ltd** (a consortium of JP Morgan and Commonwealth Bank of Australia). **ScottishPower** acquired by **Iberdrola**, which created **ScottishPower Energy Networks**.
2010		**Cheung Kong Group** acquires EDF Energy Networks, which is renamed **UK Power Networks**.
2011		**CE Electric** renamed **Northern Powergrid**. **Central Networks** acquired by **PPL (owner of Western Power Distribution)** and renamed **Western Power Distribution**.
2017		Currently 14 DNOs owned by six groups: **Electricity North West Limited** **Northern Powergrid** – Northern Powergrid (Northeast) Limited – Northern Powergrid (Yorkshire) plc **Scottish & Southern Energy** – Scottish Hydro Electric Power Distribution plc – Southern Electric Power Distribution plc **ScottishPower Energy Networks** – SP Distribution Ltd – SP Manweb plc **UK Power Networks** – London Power Networks plc – South Eastern Power Networks plc – Eastern Power Networks plc **Western Power Distribution** – Western Power Distribution (East Midlands) plc – Western Power Distribution (West Midlands) plc – Western Power Distribution (South West) plc – Western Power Distribution (South Wales) plc

Source: BEIS. This table was compiled based on research carried out by BEIS. Please note that it is intended to give an overview and may not be exhaustive.

25. The current periods have several years to run – to 2021 and 2023. It is a major weakness that there are no significant error-correction mechanisms to the formulae, and hence under RIIO these flaws are likely to persist. The cost of debt is indexed, so the companies have some (lagged) protection from rises in interest rates.

26. National Grid has voluntarily made a number of adjustments in this price control period. There have been two recent changes to the transmission price control settlement (RIIO-T1). The first was undertaken by Ofgem following the mid-period review of RIIO-T1, which reduced National Grid's allowed revenue by £185 million, primarily relating to a reduced pipeline requirement at the Avonmouth liquefied natural gas facility.[2] The second followed National Grid's notice that £480 million of investment decisions could be deferred beyond the period of RIIO-T1.[3]

27. Ofgem has recently reduced allowed revenue over RIIO-ED1 by approximately £200 million following a series of re-openers on particular DNO spending items. Electricity demand was significantly lower than expected in the 2010–15 price control, and some DNOs did not need to spend as much as expected on reinforcing their grids. Ofgem has therefore reduced allowances by a total of around £74 million across some of the distribution networks of Western Power Distribution (WPD), ScottishPower, UK Power Networks (UKPN), and SSE.

28. Some DNOs also cancelled a number of major investment projects (individual schemes worth £15 million or more), and have spent less than expected on others where they found alternative ways to complete the work. This has led Ofgem to reduce allowances by a total of around £130 million across WPD's East Midlands network and two of UKPN's networks.[4]

29. There have been no refunds or similar adjustments at the DNO level, corresponding to those of National Grid.

Options now

30. There are three ways forward in the current period. First, Ofgem could ignore the outperformance, returning the benefits to customers at the next periodic reviews, three to five years hence. This would have the merits of maintaining regulatory credibility, maximising incentives, and providing for predictability and continuity. The downside is that customers might have to pay for several more years of prices which may be in excess of costs and reasonable returns.

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[2] Ofgem's decision notice providing further detail is available at: https://www.ofgem.gov.uk/system/files/docs/2017/02/mid-period_review_decision.pdf.

[3] National Grid's notice is available at: http://otp.investis.com/clients/uk/national_grid/rns/regulatory-story.aspx?cid=374&newsid=858383. Ofgem's response, setting out the corresponding reduction in National Grid's allowed revenue is available at: https://www.ofgem.gov.uk/system/files/docs/2017/06/nget480_open_letter_final_0.pdf.

[4] Ofgem's decision notice providing further detail is available at: https://www.ofgem.gov.uk/system/files/docs/2017/09/dpcr5_closeout_decision_0.pdf.

31. Second, Ofgem could rely on 'arm-twisting' and the threat of interventions to 'persuade' the companies not to increase prices by the allowed amounts under the price cap, and make further rebates. There is evidence that this has already had some limited success. It is an approach long familiar in the water industry from the early days in the 1990s, and now actively pursued through the concept of 'painshare and gainshare'. The downside of this approach is that it is not very transparent and undermines the concept of the fixed-price contracts. Once 'Danegeld' has been paid under political and regulatory pressures, it could easily become a habit.

32. Third, Ofgem could engineer a significant interim review, and a one-off price cut now to rebase the formulae in light of the new information available. This would be more than the four-year interims in the formulae, and indeed that opportunity has already passed. It would have to be achieved by either voluntary agreement by the companies to reopen the price caps or by some other form of direct intervention. This would then need to be accompanied by a guarantee not to intervene again before the end of the current periods. The downside of this is that it breaches both a central principle of the RIIO framework and the idea that long periods are the way to go.

33. In all these options, Ofgem will need to contextualise its actions (or inaction) with its approach to the next periodic reviews. It is beyond the scope of this review to recommend which of these options should be pursued. Instead I recommend only that Ofgem should consider them urgently.

Why the periodic reviews should be abandoned in the long run

34. The assumption is that there will be another round of conventional periodic reviews based on a modified RIIO framework, and that these will start shortly. There are three reasons why the conventional periodic reviews should be abandoned: the future is fundamentally uncertain and challenged by fast technical progress; technical developments are undermining the distinction between networks on the one hand and generation, demand side and storage, and supply on the other; and there are lots of opportunities to let markets reveal costs through auctions, rather than Ofgem try to predict them. There might (and almost certainly will) still need to be a transitionary or roll-over period, but with a very different regulatory regime in mind, as I set out below.

35. Looking ahead to 2030 is an extraordinarily difficult task. It takes us well into the Fifth Carbon Budget. As described in section 6, this is likely to be a period of even greater technical change, and a host of fundamental questions for the future of regulation will arise, from the accommodation of

EVs, to the smart network and smart meter technology, to further strides in renewables technology, all within the decarbonisation context.

36. A better approach would be to accept that this is a hopeless task. Any new RIIO price formula set for the next period will almost certainly break down. It is best to assume a position of considerable ignorance, rather than to try to predict TOTEX (and hence CAPEX and OPEX) for the next decade. Building 'uncertainty mechanisms' into the periodic reviews will not solve this problem, since there are not only 'known unknowns', but in a period of fundamental technical change also 'unknown unknowns' which will need to be addressed as and when they emerge. Surprises are likely to become regular events.

37. The implication is straightforward: there should be no more conventional periodic reviews followed by further eight-year periods. The broad RPI – X regulatory framework has run its course. OPEX and CAPEX cannot be fixed sufficiently in advance to provide the necessary high-powered incentives required by RPI – X regulation. Something much more flexible is needed.

38. A second reason for abandoning the periodic review approach is that the changes in technology are undermining the distinction between transmission and distribution on the one hand, and the other activities of generation and supply, especially at the regional and local levels on the other. The periodic reviews assume there is a distinct and separate activity called 'networks'. This is increasingly untenable.

39. Consider a proposed reinforcement or extension of a distribution network. In the 1990s, and even in the 2000s, its determination was straightforward from a regulatory perspective. The DNO had the duty to connect and to deliver security of supply on its networks. It proposed, OFFER (and then Ofgem) adjudicated, and a number for CAPEX went into the formula. This was done at five-year intervals.

40. Consider the options now. The need for reinforcement or extension might be better met through an investment in local generation, a change in the type and location of local generation, by batteries and other storage, and/or by the demand side. Local generators might be part of the solutions, as might local suppliers and energy service companies, especially given that smart meters lie with supply and not distribution.

41. This blurring of the dividing lines between the three types of licences is most likely going to get more rather than less significant, and the legal and regulatory niceties of the licence distinctions will

inevitably inhibit innovative and cost-effective outcomes. For these reasons, the very basis of the periodic reviews at the local level – the distribution licence – should be reconsidered. Below I set out a long-term solution to this problem.

42. The third reason to abandon the periodic reviews coming up is that there are much better ways of establishing the lower costs than Ofgem's predictions. Consider what a DNO does. It operates its network, maintains it, and invests in its expansion. All of these activities are carried out by the licensed DNO, as only it has the statutory duties and the licence. Yet all of these activities could in theory be put out to tender, inviting other companies to bid for the operations, the maintenance, and the enhancements.

43. Although market-testing has been part of Ofgem's armoury, it has been used as a check, and not the main driver. As with FiTs and CfDs and capacity auctions, the power of auctions to bring in new and innovative ideas and lower costs is considerable. Below I explain how this could be given a prime role without losing the coordination functions currently carried out by the DNOs.

The role of the NSO and RSOs

44. One of the biggest innovations in the electricity landscape has been the enhanced role of the system operator within National Grid. This has been driven by the coming of capacity auctions, and would be further enhanced if the unified EFP auction concept were introduced, as I recommend in section 7.

45. The system operator in National Grid has thus far focused on generation and not on networks. Yet at both the national and the regional level, the system operator concept can and should be further enhanced, and it can provide a significant part of the solution to a post-periodic review world, and in the process reduce the regulatory burdens.

46. The first step is to transfer across some of the transmission and distribution licence obligations from National Grid and the DNOs to the NSO and the RSOs. In particular, the key transfer would be the security of supply requirements, and to strengthen them for the NSO and RSOs.

LICENCE CONDITIONS FOR DNOS

Under the Electricity Act 1989 the transportation of electricity may be carried out only by parties with a relevant transportation licence or which are eligible for an exemption.[1]

The standard conditions of the Electricity Distribution Licence[2] specify that licence-holders must become party to, and comply with, industry codes[3] which establish the rules that govern market operation, terms of connection, and access to the networks.

Industry codes include the Balancing and Settlement Code, the Connection Use of System Code, the Distribution Use of System Agreement, the Master Registration Agreement, the Grid Code, and the Distribution Code.

Network operators are expected to develop their network in accordance with Engineering Recommendation P2, the current distribution planning standard which ensures quality of supply on the network.

Licence-holders must also ensure that they do not restrict, prevent or distort competition in the supply or generation in electricity.

Failure to adhere to licence conditions can lead to enforcement action from Ofgem which can fine network operators or, in extreme cases, revoke their licence.

Notes: [1] Clause 4, https://www.legislation.gov.uk/ukpga/1989/29/contents; [2] https://epr.ofgem.gov.uk//Content/Documents/Electricity%20Distribution%20Consolidated%20Standard%20Licence%20Conditions%20-%20Current%20Version.pdf; 3 https://www.ofgem.gov.uk/licences-industry-codes-and-standards/industry-codes.

Source: BEIS.

47. It would now be for the NSO and RSOs to determine what operations, maintenance and enhancements to the networks are required – the higher-level outputs. Once these are established, the NSO and RSOs would have the duty to ensure they are delivered. The obvious step is to put these all out to tender. Some bidding might be for long-term contracts, other bidding might be for specific outputs and projects. There would be no five- or eight-year straitjacket, just as there are various time periods in the capacity auctions.

48. There has already been some limited experience with introducing competitive bidding. In collaboration with BEIS, Ofgem established a regulatory regime for offshore transmission owners (OFTOs) to ensure that offshore renewable generation projects are economically and efficiently connected to the electricity grid. A key part of the regime is the granting of offshore transmission licences on the basis of a competitive tender process. OFTOs bid to purchase the transmission assets from the developer and then finance and maintain the assets over a 20-year revenue stream period.

49. The NSO and the RSOs might ask themselves whether particular requirements are best met through the demand side, by storage, or by inducing new investments in generation in specific locations.

They could ask for bids from all and every option that the market might bring forward. The NSO and RSOs would not own assets. Theirs is an auctioning and coordination function.

50. It is immediately apparent that the licence boundaries break down in this more efficient model. I recommend that the distinction between distribution, generation and supply licences is abandoned. A general licence only is required, and in practice a number of the provisions in such a general licence could be met by specific clauses in contracts let by the NSO and the RSOs. This is a new and much simpler licence structure for the long-run development of the electricity industry, and it facilitates decentralised energy markets without compromising the integrity of the system as a whole.

Regulation and ownership in the NSO and RSO model

51. By placing public duties on the NSO and RSOs, these take on obligations which are currently shared between the network companies, Ofgem and the government. Under the new model, these are all concentrated on the NSO and RSOs. At a stroke, much of what Ofgem currently does in respect of network regulation is no longer needed. Indeed, it would be problematic to have two public bodies second-guessing each other. The NSO and RSOs would be publicly accountable to deliver the public interest, and to do this in as cost-effective a way as possible. Moreover, to ensure a coordinated and efficient approach to their respective activities, the NSO and RSOs should form jointly an overarching council. Ofgem might retain some residual duties, but these could probably be merged into a broader regulatory office across the utilities.

52. It is implausible for the NSO and RSOs to be owned by the current private network companies. The conflict between the private interests of the operators and the public interest of decarbonisation and security of supply is too great. It would be practically impossible to run open auctions and tenders, and to neutrally take account of generation, storage, the demand side, energy services and other options in national and decentralised networks. These bodies must be separate from National Grid (and the other transmission owners) and the DNOs.

53. The case for private ownership of the new NSO and RSOs is difficult to make. For a private business to own and run the system operators, there would need to be a clear contract, and this would inhibit the exercise of necessary discretion as the new technologies unfold. They should therefore be public bodies, accountable in the ways public agencies are – to BEIS, the Select Committees, and subject to the National Audit Office and public accounts committee scrutiny, and ultimately to Parliament.

54. The NSO and the RSOs would have a number of overlapping areas, and overall system coordination would be best ensured by establishing a council comprising the NSO and the RSOs. Consideration should be given to the relationship of this body with BEIS. One better option is for BEIS to issue formal guidance, and another is to include BEIS as a member inside the new body.

Transitional arrangements

55. The NSO and RSO model and the abandonment of the current licence framework are part of the long-run framework to deliver the twin objectives of decarbonisation and security of supply in a radically changing and digital technology world. The model breaks down the barriers between distribution and supply for the smart meters, and enhances the scope to develop new storage, the demand side, and decentralised generation. Put another way, the periodic reviews and the licence definitions are likely to become ever greater barriers to this transition, and hence slow decarbonisation and inhibit the reduction in costs for networks, and hence decarbonisation too.

56. In order to get from here to this new model, there are a number of steps that can be taken now. There should be a statement that there will be no repeat period of RIIO, and hence a statement that traditional periodic reviews will end as the current periods end. This then leaves time to establish and complete the separation of the NSO and establish the RSOs. If extra time is needed, the current reviews could be rolled over on an agreed basis for a further period until the NSOs and RSOs can take up the strain. Rollovers are a familiar part of the regulatory armoury. They could be simple, or they could be for a further short defined period. The important point is to be clear that any temporary extensions or further periods are transitory and the direction of travel is unambiguous.

57. Legislation will probably be needed to abandon the current formal licences and to introduce a new streamlined general licence and establish the NSO and RSOs. This may be complicated by any agreement to stay within the rules of the EU's Internal Energy Market. Even in this circumstance, it is evident that the breakdown of the distinctions between generation, supply and networks is widespread across Europe, and decentralised energy systems are already developing in a number of EU member states. If continued adherence to the Internal Energy Market rules makes the change legally difficult – at least in the short term – the RSOs can nevertheless be established and can operate as if the new model is the basis, and then make regulatory accounting adjustments. The legal status of the property rights that DNOs have for the current licences which have been granted for fixed licence periods – in some cases well into the future – would have to be addressed. It would, however, be hard for DNOs to obstruct the new model in practice.

58. I recommend that the scope, form and institutional powers and duties, as well as the reporting and accountability lines, for the new NSO and RSOs should be drawn up, and put out to consultation as soon as is practicable. Again, legislation will probably be required.

59. Even after the end of the periodic review periods, and with the new model in place, there will need to be provisions for an orderly transfer. It is possible, for example, that for an initial period under the new model, the incumbent DNOs may be awarded a bundled contract and hence carry on doing much of what they currently do. There is no need for a radical cliff edge: the introduction of the system operator model can be evolutionary, with a great deal of continuity built in.

60. During and after the transition, National Grid and the DNOs should be free to develop commercial activities, and to bring forward innovative storage and demand-side products.

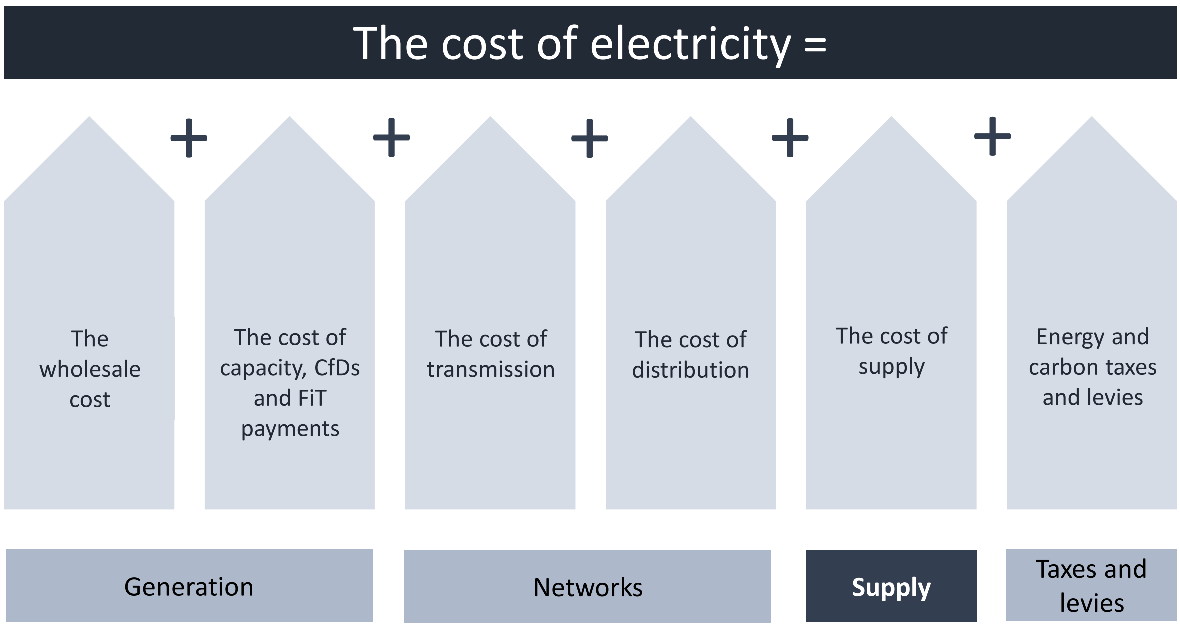
MAIN FINDINDINGS AND RECOMMENDATIONS

- Ofgem should carry out an assessment of the three options to tackle the scale of outperformance in the current periods – do nothing; arm-twisting; and a one-off resetting.
- The existing regulatory periods should be the last, and the conventional RIIO framework should be replaced when the periods come to an end, or after a shorter roll-over period, by a streamlined and much simpler model, bringing greater scope for competition and for markets to bear down on costs.
- The NSO should take on some of the duties in respect of the functions in the licences for transmission and including the duty to ensure the security of supply. A similar set of duties should be placed on the RSOs.
- The licence distinctions between distribution, generation and supply should be abandoned at the regional level, to be replaced by a single, simpler licence.
- The RSOs should determine the system requirements to ensure security of supply consistent with the carbon budgets and targets, and auction contracts for the delivery of required investments and services. These might be bundled together as in the existing DNOs, or disaggregated.
- The DNOs and suppliers can share smart meters, thereby significantly reducing their costs of capital. A regional RAB would remain, guaranteed by the RSO, and this could be securitised at a low cost of capital.
- DNOs would be free to engage in generation and supply, and hence incentivise choices between investment in new-generation capacity, including renewables, and networks.
- The role of Ofgem would be substantially diminished: there would be no further periodic reviews, and the NSO and RSOs would take on a number of regulatory functions currently performed by Ofgem.
- The NSO and the RSOs should jointly form an overarching council so that their respective activities can be coordinated.
- There would be residual regulatory roles to fulfil, and these could be absorbed into a single network regulator alongside those of water, transport and communications.

9. Electricity Supply

This section addresses:

- **the nature of retail costs, and the margins**
- **the treatment of cost pass-through**
- **the CMA detriments and the solutions**
- **the default tariff and the published margins**
- **the opportunities for enhancing competition and entry**



1. The retail supply part of the electricity value chain has historically been largely confined to metering and billing, and collecting customer payments. It has been a relatively simple business, selling a homogeneous product but without the responsibility for delivering it physically.

2. Over time, retail suppliers have added functions. These include the collection of levies (see section 10); collecting the system costs of transmission and distribution; engaging in hedging and other wholesale price and volume risk management; and, most recently, the roll-out of smart meters.

3. A number of suppliers have also engaged in multiple product sales, including gas boilers and other appliances (and indeed, pre-privatisation, the Regional Electricity Companies had appliance businesses and often high street shops too). They have tried selling other utility services and household maintenance services. The new departures into energy services open up the possibility

of a significant change in the very meaning of supply, and an end to the concept of a narrow supply-only business. It is here that the new smart technologies will probably have most impact on customers, beginning to break down the distinctions at the regional level between supply, distribution and generation. In sections 8 and 11 I make proposals to remove some of the barriers to these exciting possibilities.

4. Under the monopoly, which applied until full liberalisation in 1998, customers took their supplies from their local supply company (the Regional Electricity Companies), and the tariffs paid for the retail activities were set by regulators through retail supply price caps.

5. These price caps persisted in some cases beyond 1998. The most recent is the Northern Ireland Supply Price Cap. The details are set out below, alongside a comparison of margins with non-regulated supplies.

NORTHERN IRELAND'S SUPPLY PRICE CAP AND OTHER SUPPLY PRICE CAPS

NORTHERN IRELAND PRICE REGULATION

UREGNI sets the maximum allowed price per unit of electricity that Power NI may charge. This is determined by the following formula:

$Mt = Gt + Ut + St + Kt + (Jt – Dt) + Et$

In any given year *t*:

Gt refers to the cost of the 'wholesale' electricity which Power NI purchases, and so long as Power NI complies with its Economic Purchasing Obligation, this will be passed directly through to customers via the regulated tariff.

Ut covers the costs of using the electricity network; these costs are regulated for all suppliers through the NIE Transmission and Distribution price controls.

Kt is a correction facility whereby under- or over-recoveries in the previous year can be collected by the business (under-recovery) or given back to consumers (over-recovery).

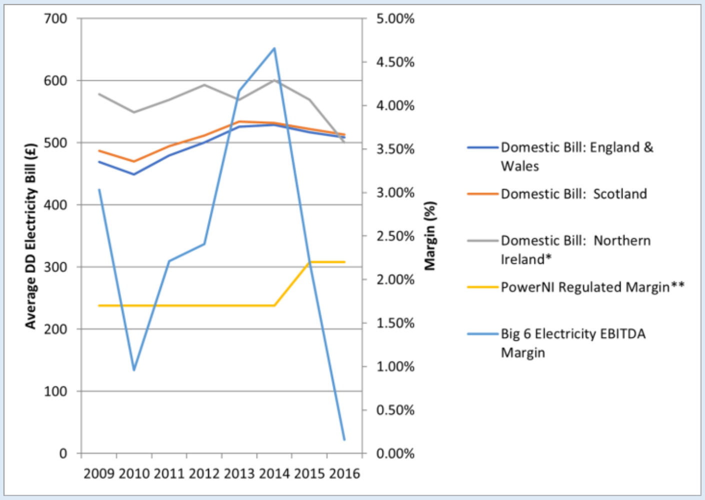
Jt encompasses costs associated with buy-out from the Northern Ireland Renewables Obligation, with the *Dt* term representing any savings on the buy-out Power NI achieves.

Et is associated with costs which are uncontrollable and are passed through to customers via the regulated tariff on a 100% basis. These costs include licence fees; approved IT projects spend required in order to put in place the systems and processes to comply with licence obligations; and pension deficit costs incurred before 31st March 2015. The *Et* element of the control is reviewed and amended in the licence as part of each price control-setting process.

As demonstrated above, the majority of Power NI's costs that go into regulated end-tariffs are straight 'pass-through' costs which are subject to other price controls or regulations; and thus this price control review deals principally with the *St* term of the tariff formula (along with the aforementioned *Et*), which is in effect Power NI's own operating costs and net profit margin allowed by the regulator. This amount must be sufficient to finance an efficient business of the licensee and should comprise the following elements: operating costs; and the allowed margin.

The allowed revenue of *St* is currently collected on a ratio of a 70% fixed amount plus a 30% variable amount collected on a per-customer basis. This was reviewed as part of the last control and, as a result, it was determined that the split should be adjusted slightly (moving to 70:30 from 67:33).

FIGURE 37: MARGIN COMPARISON



	Domestic bill: England and Wales (£)	Domestic bill: Scotland (£)	Domestic bill: Northern Ireland (£)[1]	Power NI regulated margin[2]	Big Six electricity EBITDA margin
2009	469	487	578	1.7%	3.03%
2010	449	470	549	1.7%	0.96%
2011	480	495	569	1.70%	2.21%
2012	501	512	593	1.70%	2.41%
2013	526	534	569	1.70%	4.17%
2014	529	532	601	1.7%	4.66%
2015	517	522	569	2.20%	2.20%
2016	509	513	501	2.20%	0.16%

Notes: 2010 prices. EBITDA, earnings before interest, tax, depreciation and amortisation. [1] This is not equivalent to the average bill of a Power NI customer, which is given below in nominal prices.
[2] Power NI's margin is provided with the following caveats.

- The margin is for domestic plus commercial up to 50MWh. The Big Six margin is for domestic only. Power NI has been exclusively regulated on the domestic side since April 2017.
- The margin here is that specified by UREGNI – Power NI was able to overperform if it grew its customer base (under price control formula part of allowance is variable and if it increases its customer numbers it gets an increased amount of money), or outperform its regulatory targets (ie, OPEX allowances set in the price control). The margin is expressed as a percentage of forecast turnover rather than a floating amount; this is translated into an amount of money which is fixed so does not vary with turnover. Therefore, the outturn margin as a percentage of turnover could be higher or lower.

Source: BEIS, based on UREGNI information.

6. It is important to add a number of caveats to any simplistic comparison of the margins in the liberalised GB market and those of regulated ones. In a liberalised market, suppliers face risks in respect of hedging and the loss of customers. These can all, however, be handled in the default tariff I recommend below through error-correction and cost-recovery mechanisms. Power NI is able to recover its pass-through costs under its regulatory settlement. Being unable to recover costs has been observed in the GB domestic electricity supply market – with several Big Six suppliers making losses in recent years. This is a matter of design and regulation, and of risk allocation.

The CMA approach

7. THE CMA extensively investigated the supply businesses, and in particular the SVTs which non-switching customers are on. They are *standard*, in that all non-switchers are on them, and they are *variable*, in that suppliers can put them up (or down) at their discretion.

8. The CMA's main findings are as follows.

SUMMARY OF CMA ANALYSIS OF DETRIMENT: DIRECT AND INDIRECT APPROACH

In its final report the CMA adopted two approaches to assessing the extent to which prices are excessive – ie, have exceeded those which would be expected in a well-functioning market (this is the 'customer detriment').

(a) A 'direct' approach, which involves comparing the average prices charged by the Six Large Energy Firms with a competitive benchmark price which is based on the prices charged by the most competitive suppliers (OVO and First Utility), adjusted to allow for a normal return on capital and where appropriate for differences in suppliers' size, rate of growth and the cost elements that are outside of their control.

(b) An indirect approach, which involves assessing both:
   (i) the Six Large Energy Firms' levels of profitability (and in particular whether the return on capital employed by such suppliers exceeds their cost of capital); and
   (ii) the extent to which the Six Large Energy Firms have incurred overhead costs inefficiently (ie, whether costs are higher than the CMA estimates an efficient supplier would incur).

Under the direct approach the CMA estimated that domestic customer detriment averaged £1.4 billion per year over the period 2012–15. Under the indirect approach the CMA estimated that domestic customer detriment was around £720 million/year over the 2007–14 period.

One of the reasons for this difference in the CMA's calculations in detriment arises because of the different time periods examined. When adjusting the time period to allow a like-for-like comparison, the indirect approach yields an estimate of detriment of £1.1 billion/year versus £1.2 billion/year for the direct approach for the period 2012–14. Another reason relates to the conservative approach adopted by the CMA to identifying the level of profits above the industry cost of capital made and the efficient indirect cost base of the Six Large Energy Firms.

Source: BEIS, based on Competition & Markets Authority (2016), 'Energy Market Investigation: Final Report', June.

9. The identified detriment under both approaches was heavily contested by the companies. There is no precise right answer since it requires the competitive benchmark price to be correctly identified under the direct approach; the cost baseline assessment of efficiency to be correctly specified for the indirect approach; and an analysis of margins separate from returns on the limited capital at risk in these asset-life businesses.

10. There are obvious problems with the competitive benchmark – notably that OVO and First Utility are pricing into a market distorted by the market power the CMA identified. The competitive benchmark price is likely to be lower.

11. The CMA's focus on returns to capital is questionable: retail is a margins business, employing very little capital, other than working capital. The risks that equity-holders face for SVT customers are from poor hedging, inefficient billing and poor customer services, failures in their IT systems, and

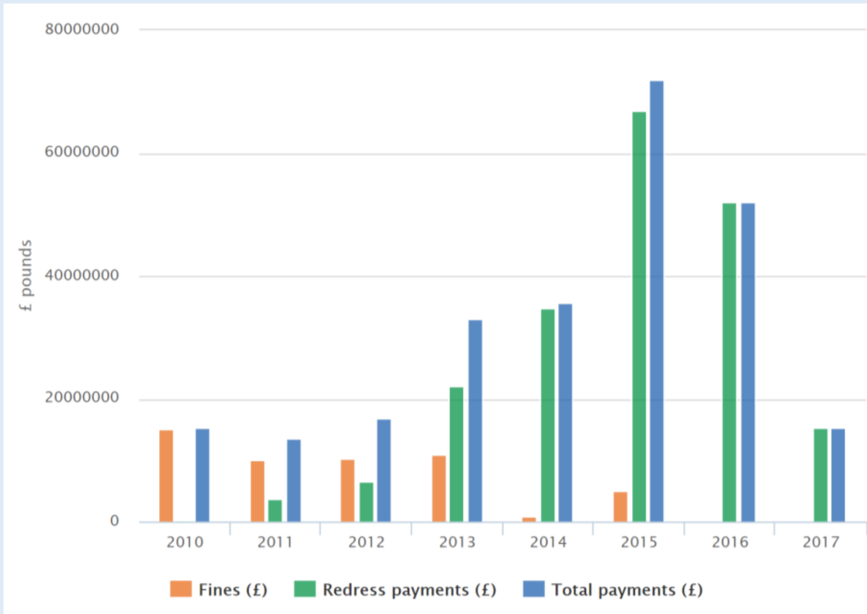
from cash management and bad debts. The actual performance may reflect inefficiencies – indeed this is one of the findings of the CMA.

12. The evidence is that the major suppliers have from time to time indeed offered poor, and sometimes very poor, customer service. There have been large fines imposed by Ofgem, and the box below illustrates the sorry record. The chart and list are only for the enforced cases – there are a further substantial number of negotiated cases which do not reach enforcement. Hedging has at times been poor. The hedging performance is one explanation of why margins fell back so sharply in 2016. There have been significant IT systems failures.

FINES FROM OFGEM

The chart and table below detail the financial penalties imposed on energy companies by Ofgem since 2010. These include fines (penalties paid directly to the Treasury) and redress payments (where an arrangement is reached with a company to take action that will directly benefit consumers), such as payments to social programmes like the Warm Home Discount.

FIGURE 38: TOTAL FINES AND REDRESS PAYMENTS SINCE 2010



Decision date	Company	Case type	Fine (£)	Redress payment (£)	Total (£)
2017 July	British Gas	Guaranteed Standards	0	1,100,000	1,100,000
2017 June	British Gas	Standards of Conduct, Complaints Handling, Billing, Contract Information	1	9,499,999	9,500,000
2017 Feb	Western Power Distribution	Error in Distribution Charges	0	300,000	300,000
2017 Jan	British Gas	Missed Deadlines	1	4,499,999	4,500,000
2016 Dec	OVO	Guaranteed Standards	0	58,000	58,000
2016 Oct	Co-operative Energy	Transfers, Billing and Complaints Handling	0	1,800,000	1,800,000
2016 Sep	E.ON	Guaranteed Standards	0	3,100,000	3,100,000
2016 June	ScottishPower	Standards of Conduct, Complaints Handling and Final Bills	1	17,999,999	18,000,000
2016 March	National Grid	Failure to Meet Price Control Target	0	3,000,000	3,000,000

2016 Jan	npower	Standards of Conduct, Complaints Handling and Final Bills	7	25,999,993	26,000,000
2015 Dec	BES	Contract Terms, Standards of Conduct and Complaints Handling	2	1,317,377	1,317,3792
2015 Dec	E.ON	Missed Deadlines	2	6,999,998	7,000,000
2015 Dec	Economy Energy	Misselling	1	249,999	250,000
2015 Nov	Utilita Energy	Transfer Blocking	1	559,999	560,000
2015 May	E.ON	Tariff Rules	1	7,749,999	7,750,000
2015 April	Spark Energy	Transfers, Billing and Complaints Handling	1	249,999	250,000
2015 March	SSE	Transmission Constraints	0	100,000	100,000
2015 March	Intergen	Missed Deadlines	3	10,999,997	11,000,000
2015 March	Drax	Missed Deadlines	5,000,000	23,000,000	28,000,000
2015 March	British Gas	Missed Deadlines	1	10,599,999	10,600,000
2015 March	British Gas	Missed Deadlines	1	499,999	500,000
2015 March	ScottishPower	Missed Deadlines	2	2,399,998	2,400,000
2015 March	SSE	Missed Deadlines	9	1,749,991	1,750,000
2015 March	GDF Suez	Missed Deadlines	2	449,998	450,000
2014 Oct	EDF	Complaints Handling	1	3,000,000	3,000,001
2014 July	SSE	Network Connections	0	4,600,000	4,600,000
2014 July	UKPN	Network Connections	0	3,400,000	3,400,000
2014 July	British Gas	Misselling	0	1,000,000	1,000,000
2014 July	ScottishPower	Tariff Rules	1	750,000	750,001
2014 July	E.ON	Misselling	1	12,000,000	12,000,001
2014 May	SSE	Network Connections	0	750,000	750,000
2014 June	npower	Misreporting	125,000	959,900	1,084,900
2014 May	British Gas Business	Switching Practices	0	1,650,000	1,650,000
2014 May	British Gas	Switching Practices	800,000	3,200,000	4,000,000
2014 Feb	npower	Misselling	1	3,500,000	3,500,001
2013 Dec	ScottishPower	Misselling	1	8,500,000	8,500,001
2013 Dec	npower	Customer Service	0	1,000,000	1,000,000
2013 Aug	E.ON	Misreporting	500,000	2,500,000	3,000,000

2013 June	British Gas	Incorrect Billing	0	10,000,000	10,000,000
2013 May	SSE	Misselling	10,500,000	0	10,500,000
2012 Nov	E.ON	Incorrect Billing	0	1,700,000	1,700,000
2012 Oct	Opus Energy Ltd	Misreporting	125,000	359,500	484,500
2012 Oct	Wales and West Utilities Ltd	Misreporting	375,000	0	375,000
2012 May	EDF	Misselling	1	4,500,000	4,500,001
2012 Feb	National Grid Gas	Emergency Standards	4,300,000	0	4,300,000
2012 Feb	Northern Gas Networks Ltd	Emergency Standards	900,000	0	900,000
2012 Jan	npower	Complaints Handling	2,000,000	0	2,000,000
2012 Jan	British Gas	Complaints Handling	2,500,000	0	2,500,000
2011 Nov	British Gas Business	Misreporting	1,000,000	3,438,000	4,438,000
2011 Aug	EDF	Consumer Protection	0	200,000	200,000
2011 May	National Grid Gas	Misreporting	8,000,000	0	8,000,000
2011 April	Electricity North West	Network Connections	100,000	0	100,000
2011 April	Central Networks	Network Connections	400,000	0	400,000
2011 April	SHE Power Distribution	Network Connections	500,000	0	500,000
2010 Aug	National Grid	Competition Act 1998	15,000,000	0	15,000,000
2010 June	EDF	Complaints Handling	0	200,000	200,000

Source: Ofgem investigations and enforcement data, correct as of July 2017. Available at https://www.ofgem.gov.uk/investigations/investigations-and-enforcement-data.

13. These are all risks that shareholders should bear, and in a fully competitive market all the major suppliers would have lost a much greater proportion of their customer base. Sticky customers allow such practices to persist. Some of the practices of the major suppliers have added to the stickiness, by offering multiple tariffs, reducing the ability of customers to understand what is being offered to them, and reducing trust as some customers who switched ended up worse off. It is not in the interests of the main large suppliers to encourage their customers to switch.

14. Ofgem tried to address the multiple tariff problem by proposing a radical simplification. The Retail Market Review (RMR) reduced the number of tariffs to just four per provider. In a context in which customers were largely unable to comprehend the multiple offerings, and make informed judgements about which was best for them, this was a step forward. It is summarised in the box below.

15. RMR was heavily criticised by the CMA. Restricting suppliers' offerings was deemed to be an unwarranted interference in the competitive market. The CMA's solution did not, however, address the problem to which RMR purported to be an answer. Below I recommend a solution, by requiring a default tariff on a common basis to be offered by all suppliers, leaving the companies free to offer any of the other tariffs they wish alongside the default tariff.

Ofgem's summary of RMR reforms: simpler, clearer, and fairer

Following its RMR, which found that the market was not working as well as it could for consumers, Ofgem introduced a major package of reforms aimed to make the market 'simpler, clearer and fairer' for consumers.

Simpler choices

Introduced in January 2014, these key reforms aimed to make it simpler for consumers to understand and compare the energy tariffs offered by suppliers. Ofgem:

- banned complex tiered tariffs and introduced a new tariff structure, a unit rate (or unit rates for time-of-use tariffs) and a standing charge (which could be zero), to make tariffs more consistent and easier to compare;
- limited the range of tariffs suppliers could offer to four core tariffs for both gas and electricity;
- condensed the cash discounts suppliers could offer to two options:
  - a dual-fuel discount, when a consumer took both gas and electricity from the same supplier;
  - a paperless discount when consumers opted to manage their accounts online.

Ofgem obligated suppliers to display these in a simple £/year format. It also banned restricted discounts that made it difficult to compare costs of tariffs.

Clearer information

Introduced in March 2014, these key reforms aimed to make billing information and communications from suppliers clearer for consumers. Ofgem required suppliers to:

- give all their customers personalised information on the cheapest tariff they offer, including in bills, annual statements and other communications;
- provide more informative bills, which include key information about the customers' tariff and how much energy they use;
- compare old and new prices in a simple £/p format when informing customers of a price increase;
- provide more informative and easy-to-use annual statements, which include facts about the customer's tariff (including discounts), tariff end-date, whether any termination fees apply, and information on how to switch supplier;
- comparison of old and new prices in a simple £/p format when informing customers of a price increase.

Ofgem also required suppliers to introduce new tools to help customers compare tariffs:

- to produce a Tariff Information Label for each of tariff in a standardised way. The label contains a number of key facts about the tariff, including payment method, discounts, termination fees, and an estimate of the annual cost of the tariff for a typical consumer;
- to use a new Tariff Comparison Rate in bills and a range of other communications to provide 'at-a-glance' information to help customers compare tariffs – similar to the annual percentage rate used to compare credit cards;
- to provide personalised annual cost projections based on the customer's actual consumption (or, where this is unavailable, the best estimate of their consumption). This

includes on bills and a range of other communications, so customers can compare tariffs more accurately when assessing their options.

FAIRER TREATMENT

Introduced in August 2013, these key reforms aimed to ensure through the introduction of new enforceable Standards of Conduct for domestic consumers that suppliers and any organisation that represents them, such as brokers or third-party intermediaries, treat their customers fairly. Standards of Conduct for business consumers requiring energy suppliers to treat small businesses fairly were also introduced in August 2013.

The onus was put on suppliers to embed fair treatment of consumers at every level of their organisation. This was to cover all dealings with the consumer, including information sent in writing as well as calls with the customer regarding a query or complaint.

The standards required suppliers to:

- carry out all these actions in an honest, transparent and professional manner;
- ensure that any information to consumers is communicated in clear jargon-free language;
- make it easy for consumers to contact them, and act promptly and courteously to put things right;
- publish yearly statements presenting the actions taken to treat consumers fairly.

Alongside the standards, Ofgem also implemented measures which meant that:

- consumers no longer have to inform their current supplier if they intend to switch;
- if a customer switches in the case of a price increase, even if this is after the date the price rise comes into effect, as long as they switch soon after the increase and it completes in a reasonable time, the customer will not have to pay the higher rates;
- if a customer signs up to a fixed-term deal, on or after 15th July 2013, the supplier is not able to increase the price;
- customers would receive a notice 42–49 days before the end-date of a fixed-term tariff to inform them the tariff is coming to an end. If a customer chooses to switch after this point, suppliers cannot charge a termination fee;
- if a customer chooses not to switch at the end of a fixed-term tariff, they cannot be rolled onto another fixed-term tariff with a termination fee. They would instead be rolled automatically onto the cheapest standard tariff with the supplier;
- any customers who are on old, expensive, evergreen tariffs that are no longer open to new customers (so-called 'dead tariffs') would be switched to their supplier's cheapest variable rate from June 2014.

Source: Ofgem.

16. The margins that the companies are charging are further confused by the bundling of electricity and gas into dual-fuel products. Companies have considerable control over how costs are allocated between the two fuels. Thus the reported return on capital is likely to be somewhat arbitrary between the two. The Terms of Reference for this review focus on electricity.

17. The evidence on margins is as follows.

TABLE 18: DOMESTIC SUPPLY MARKET SHARES IN GREAT BRITAIN (%)

Electricity	Q4 2013	Q4 2014	Q4 2015	Q4 2016	Gas	Q4 2013	Q4 2014	Q4 2015	Q4 2016
Centrica	24	24	23	23	**Centrica**	39	38	37	35
E.ON	16	16	15	14	**EON**	13	12	12	10
EDF	13	13	12	12	**EDF**	9	9	8	8
npower	12	11	10	10	**npower**	10	9	9	9
ScottishPower	12	11	11	11	**ScottishPower**	9	9	9	9
SSE	18	17	16	15	**SSE**	15	14	13	12

Source: Ofgem.

TABLE 19: DOMESTIC SUPPLY EBIT MARGINS IN GREAT BRITAIN

Electricity	2013	2014	2015	2016	Gas	2013	2014	2015	2016
Centrica	0.8	1.4	0.3	–3.9	**Centrica**	8.9	7.8	12.5	15.1
E.ON	7.0	5.0	4.0	3.0	**E.ON**	0.2	4.2	5.0	12.4
EDF	–1.1	1.5	–1.3	–2.8	**EDF**	–5.3	–3.3	0.3	2.4
npower	5.3	2.0	–7.0	–9.0	**npower**	1.2	3.5	–6.4	–2.5
ScottishPower	7.6	8.2	5.7	3.0	**ScottishPower**	1.1	2.4	5.7	8.4
SSE	3.4	6.1	2.8	1.8	**SSE**	4.6	6.0	11.4	15.1
Big Six	3.6	3.9	1.1	–1.2	**Big Six**	4.2	4.9	7.6	11.1

Source: BEIS, based on Ofgem Consolidated Segmental Statements (financial years).

18. These tables reveal slightly lower margins for the Big Six than those provided in the box above on the Northern Ireland comparisons. The difference between these numbers and those set out above reflect those between EBIT and EBITDA. For the purposes of the discussion here I use the BEIS numbers. They reveal some interesting features of the supply market. The numbers vary a lot between companies, and they jump around a lot between the years. It is no accident that the margins are lower in 2015 and much lower in 2016. This follows from the shock to fossil fuel markets in late-2014. Given that the strategies of the companies are private information, one can only speculate about the reasons. It looks as if some of the companies got their hedging wrong. In some cases there were also complaint-handling problems and customer losses. This probably further contributes in particular to npower's very poor results. Another feature is the difference between gas and electricity, and raises questions about cost allocation between the two.

Recalculating the supply margins

19. The conventional margins analysis understates the economic margins that suppliers are earning. It is a margin on the full electricity supply chain, much of which the suppliers do not control. Suppliers do not control the FiTs, low carbon CfDs, capacity contracts, transmission and distribution costs, and other taxes and levies. Since the suppliers have in any event to bill and meter, and to address the debt collection, the extra-narrow costs for collecting these fixed costs are limited, and below I recommend ways of dealing with these. The margins should therefore also be calculated on the basis of only what they do control, and exclude everything else. On this basis, the numbers are correspondingly much bigger, as is the corresponding detriment. The CMA largely ignored this aspect.

20. In order to identify the costs under the control of the suppliers, and not those that are exogenous to them, I asked BEIS to carry out the following calculations.

21. First, BEIS took domestic supply EBIT *divided by* total domestic supply revenue *minus* network costs *minus* environmental/social costs.[5] The margins under this approach are as follows.

TABLE 20: PERCENTAGE SUPPLIER OPERATING PROFIT MARGIN ON THE REVENUES THAT WOULD HAVE BEEN GENERATED IF THE VALUE OF NETWORK AND ENVIRONMENTAL/SOCIAL COSTS IS STRIPPED OUT (%)

Electricity	2013	2014	2015	2016	Gas	2013	2014	2015	2016
Centrica	1.3	2.3	0.4	–7.2	**Centrica**	11.8	11.0	16.7	20.6
E.ON	10.9	8.1	6.7	5.3	**E.ON**	0.2	5.9	6.9	16.9
EDF	–1.8	2.5	–2.2	–4.9	**EDF**	–7.4	–4.6	0.4	3.4
npower	8.3	3.2	–12.1	–16.5	**npower**	1.7	4.8	–9.0	–3.5
ScottishPower	12.4%	13.3	9.5	5.5	**ScottishPower**	1.5	3.4	7.8	12.1
SSE	5.6	9.8	4.6	3.2	**SSE**	6.4	8.2	15.2	20.4
Big Six	5.8	6.3	1.8	–2.1	**Big Six**	5.7	6.9	10.3	15.3

Source: BEIS, based on Ofgem Consolidated Segmental Statements.

22. Second, BEIS took domestic supply EBIT *divided by* total domestic supply revenue *minus* network costs *minus* environmental/social costs *minus* direct fuel costs.

[5] Direct costs other than direct fuel costs have been separated out into three components since 2013: network costs, environmental/social costs and other direct costs. Prior to 2013, direct costs other than direct fuel costs were reported by suppliers as a single figure, not broken down into these components.

TABLE 21: PERCENTAGE SUPPLIER OPERATING PROFIT MARGIN ON REVENUES IF THE VALUE OF NETWORK, ENVIRONMENTAL/SOCIAL COSTS AND DIRECT FUEL COSTS IS STRIPPED OUT (%)

Electricity	2013	2014	2015	2016	Gas	2013	2014	2015	2016
Centrica	5.0	8.2	1.4	-23.2	Centrica	41.5	34.3	43.1	43.3
E.ON	35.1	25.6	21.4	15.8	E.ON	1.2	21.3	23.0	41.9
EDF	-6.7	8.2	-7.7	-17.3	EDF	-45.0	-22.7	1.8	10.9
npower	25.1	9.2	-41.1	-49.8	npower	7.3	15.0	-32.9	-9.2
ScottishPower	43.4%	40.3	28.4	16.5	ScottishPower	8.7	13.7	25.2	30.3
SSE	24.7	35.1	17.7	10.8	SSE	28.6	32.1	43.8	45.5
Big Six	20.6	20.7	6.0	-6.7	Big Six	24.2	24.2	30.4	35.6

Source: BEIS, based on Ofgem Consolidated Segmental Statements.

23. The calculations show that, with the exception of 2016, the margins go up significantly. Stripping out exogenous costs and calculating margins based on the revenues that would have been generated if these costs did not exist assumes that there are no costs or risks to suppliers from what is effectively, from an economic perspective, a rent-collecting activity. In practice there are a number of costs and risks, and there are a number of ways of handling them, from *ex post* error corrections to an increase in the margin. These include:

(i) Forecasting errors for the coming period to comply with various schemes. These can be dealt with through an *ex post* error-correction mechanism in the default tariff I recommend.

(ii) Bad debt, which again could be a cost pass-through item in the default tariff.

(iii) Working capital is required for the gap between billing, receiving payments, and the due date for payment for the exogenous costs.

(iv) Loss of customers in advance of recovering cost pass-through elements.

A fair margin

24. What would a fair margin be on the costs the suppliers actually control? We have the benchmarks of the regulated margins reported above for Northern Ireland and earlier supply price controls. These show that in the British unregulated market, customers can pay twice the margin, and in the context of considerable inefficiencies. The Northern Ireland margin is calculated on controllable costs.

25. There are good reasons for expecting these margins to fall for all customers. New technologies should reduce the costs of handling customer databases, and the coming of smart meters and broadband hubs as the focus of household utility services should make it easier for new entrants from outside the electricity industry to offer bundled products over and above electricity and gas.

Over time, a host of retailers, service providers and other utilities should be able to offer multiple services, eroding the margins – perhaps radically. The default tariff I recommend below will intensify competitive pressures on these margins, and thereby provide more relief to customers from the detriment found by the CMA.

26. Finally, the data itself is valuable for purposes other than the simple supply of electricity. This will raise many regulatory and privacy issues, and it is likely that this will be of extra value to the smart meter operators and suppliers.

27. Whatever the precise number, and even with some adjustment, the CMA found one of the largest detriments ever – by it or its predecessors. Up to 70% of customers have been paying a significant premium as a penalty for not switching supplier.

28. There are several possible remedies to this situation. These are:
    - (i) allow it to persist in order to maximise the incentives to switch;
    - (ii) cap the prices to some proportion of SVT customers;
    - (iii) provide full transparency through a default tariff, either as a version of a comprehensive SVT price cap, or instead.

(i) Allow it to persist in order to maximise the incentives to switch

29. The case for inaction is based on the central assumption made by the CMA that the problem of insufficient switching is a temporary problem, and intervention will reduce switching. This in turn assumes that switching is an unambiguously good idea, whereas in fact the act of switching is a deadweight welfare loss to customers.

30. The CMA held out high hopes that the coming of smart meters would transform the customer interface and that many of the barriers to switching would be removed. What the CMA failed to note is that as time goes by the proportion of total costs which are amenable to switching competition is falling. As more and more zero marginal cost generation comes onto the system, the fixed-cost elements will increase as a proportion of the total bills. There will be less and less to switch from – competing suppliers will be offering the same fixed costs to all customers. Customers will be switching from one supplier of a common set of fixed system costs to another, in a largely capacity-focused market. The cost pass-through elements, and hence the role of suppliers as revenue collectors, will increase. They are collecting the levies and charges for the capacity

contracts, the FiTs, and the transmission and distribution system costs. The wholesale cost will fall as a proportion of total costs as the capacity costs go up. This is a central finding of sections 6 and 7.

31. The smart meters will provide important data to the system operators – both the NSO and RSOs – but they will not in themselves add much to the incentives to switch.

32. The further argument for imposing excessive charges on the SVT customers is that the profits provide an incentive for competitors and entrants to go after. The bigger the margins, the greater the competition. This is a classic Austrian economics argument.

33. It is undoubtedly the case that the bigger the profits the greater the incentive for entry. But this requires existing SVT customers to continue to be subjected to the excess charges as a 'price worth paying' for competition. It could be argued that this confuses means and ends. The end is not competition: it is fairly priced services to customers, receiving efficient services. It is not continuing to argue that SVT customers, loyal to their suppliers, should carry on paying for the benefits to those who switch – and hence excess margin to suppliers. Although the total detriment per annum may fall from £1.4 billion, it is likely to persist for some considerable time to come.

(ii) Cap the prices to more vulnerable SVT customers or some proportion of them

34. A second approach is to cap the prices to SVT customers deemed to be poor and/or vulnerable, leaving the rest of the SVT customers exposed to the excess costs.

35. Given that electricity is a greater proportion of the fuel bills of the poor, there is some merit in this approach. The prepayment meter (PPM) cap already addresses part of this group of customers. It has been suggested that it should be extended to a larger group, and draft legislation has been introduced with a view to a much more comprehensive cap (see below).

36. Like all price caps, including in the Northern Ireland price control described above, the level of the PPM cap depends on the basic building blocks of costs, and requires flexibility to reflect changes in these. The PPM cap is described below.

THE PREPAYMENT METER PRICE CAP

The price cap covers all domestic prepayment customers in Great Britain, except those with a fully interoperable smart meter.

The price cap applies to all single-fuel gas and electricity tariffs made available to new domestic prepayment customers, and to all the single-fuel gas and electricity tariffs in place through existing contracts with relevant customers. For dual-fuel tariffs, suppliers have to ensure that each single-fuel component complies with the relevant maximum charge for each fuel.

There are around 4.4 million PPM electricity accounts and 3.5 million PPM gas accounts (representing 17% of all domestic electricity accounts and 15% for gas).[1]

The price cap came into effect from 1st April 2017 and is due to expire at the end of 2020 when the smart meter roll-out is expected to be complete. The CMA will review the cap remedy in January 2019 against progress made on the roll-out of smart meters.

The level of the cap is updated every six months with effect from 1st April and 1st October each year (published in February and August). Ofgem is responsible for administering the cap.

The cap is calculated based on a predetermined set of formulae using a 'hybrid reference price and cost index approach'. This involves setting a base level of the prepayment cap based on the CMA's competitive benchmark analysis (see below), and then allows the cap to change over time according to movements in exogenous cost indices. The adjustments will explicitly allow for movements in wholesale energy costs, network costs, policy costs affecting household energy supply, and 'other' costs due to inflation.

Levels of the cap are published for a customer who does not use any energy (nil consumption) and for one who uses the medium typical domestic consumption values (TDCVs) that applied for the period from January 2014 to August 2015 (3,200kWh for electricity, 4,600kWh for Economy 7, and 13,500kWh for gas). The level of the cap for all other possible consumption levels can then be determined using linear interpolation between these values.

The price cap is set separately for prepayment customers across regions; this is to reflect underlying cost differences (eg, network costs) in each region. In addition, there are two separate caps generated for electricity: one based on Single-Rate metering and one based on Economy 7 metering. The cap is set excluding VAT.

Base Level of Cap + Allowances

The base level of the cap is based on the CMA's benchmark for an efficient supplier, calculated with reference to the different tariffs offered on 30th June 2015 by the two most competitive mid-tier suppliers: OVO Energy and First Utility, adjusted where appropriate for a range of factors including cost elements that are outside their control. The competitive benchmark is based on prices for direct debit tariffs. The overall level of the cap is then determined by adding on the allowances for the cost to serve prepayment customers, network costs, and any headroom to the base level.

Indexing

The overall price cap (base level plus allowances) is adjusted at regular intervals for movements in input costs since 30th June 2015 ('cost-indexing'). The adjustments explicitly allow for movements in wholesale energy costs, network costs, policy costs and 'other' costs due.

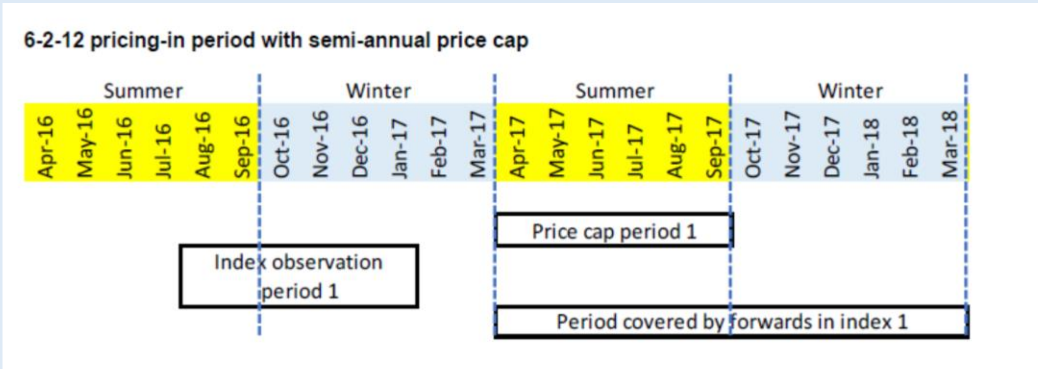
(i) Wholesale cost indexing

This takes market prices for standard wholesale products from ICIS – specifically using market prices for energy products traded for delivery in the day(s), month(s), quarter(s) and season(s) ahead. The index measures movements since the end of June 2015 in the cost of delivering gas and electricity to domestic customers.

The CMA went with a 6–2–12 pricing-in period used in conjunction with semi-annual price cap updates. 6–2–12 refers to the different periods involved – wholesale prices are observed over a six-month period. There is a two-month lag between the end of the observation period and the start of the price cap period. The wholesale prices observed are the forward prices for energy delivered over a 12-month period. The 12 months covered by the forwards in the index start on the same date as the price cap. The approach is illustrated below.

Note: [1] Competition and Markets Authority (2016), 'Energy Market Investigation: Final Report', June.

FIGURE 39: PRICE CAP APPROACH



For electricity the index is calculated using a weighted average of peak and baseload products. Baseload is weighted 70% and peak is weighted 30%, reflecting Ofgem's assumptions.

The base value for the wholesale index is the value that would have applied for the price cap period 1st April 2015 to 30th September 2015 (had the price cap been in effect then).

(ii) Network cost indexing

Network costs are updated using network company charging statements.

(iii) Policy cost indexing

For electricity, these are uprated using the Office for Budget Responsibility's expected increase in policy costs published alongside the March and Autumn fiscal events. For gas, policy costs are assumed to stay constant over the period.

(iv) Other costs (previously referred to as 'indirect' costs)

This includes an allowance for an EBIT margin. The CMA considers that an EBIT margin of 1.25% allows for a level of profit consistent with competitive pricing by an energy supplier which has reached an efficient scale (ie, a large supplier), and which is in a steady state.

The CMA expects that, over time, the 'other costs' element of the competitive benchmark will be subject to two opposing forces: inflation and efficiency. To be prudent, the CMA decided that the base level of other costs is subject to inflation in line with the Consumer Price Index (CPI).

(v) Prepayment meter costs (termed 'prepayment meter uplift allowance')

The CMA considered that a reasonable level of costs-to-serve differential between those customers on direct debit and those on prepayment should be £63 (£24 electricity; £39 gas). These cost-to-serve differentials are adjusted in line with the CPI.

Each update uses the CPI figure for the month three months prior to the start of the price cap period.

(vi) Headroom

The CMA considered it appropriate to include an element of headroom in the price cap to allow for competition. This is specified as a percentage of the pre-headroom price cap level excluding network costs. Network costs vary regionally and are known with a reasonable degree of precision, and the CMA therefore considered it inappropriate for the level of headroom to vary regionally. Based on its analysis of headroom, it concluded that at medium TDCVs, £15 is a suitable level of headroom for each fuel, which translates into the following percentages.

TABLE 22: HEADROOM ALLOWANCES

	Headroom allowance (%)
Gas	3.48
Electricity	4.23
Electricity Economy 7	3.41

Source: Competition and Markets Authority (2016), 'Energy Market Investigation: Final Report', June, Table 14.2, available at https://assets.publishing.service.gov.uk/media/5773de34e5274a0da3000113/final-report-energy-market-investigation.pdf.

37. Table 23 shows the level of the PPM price cap over the two periods to date, based on current TDCVs.

TABLE 23: THE PPM PRICE CAP (£, EXCLUDING VAT)

	Electricity (non-Economy 7)	**Gas**	**Electricity (Economy 7)**	**Dual fuel (single rate)**
1st Apr–30th Sept 2017	£547.07	£520.07	£625.85	**£1,067.14**
1st Oct–31st Mar 2018	£528.26	£519.74	£600.13	**£1,048.00**

Source: Ofgem.

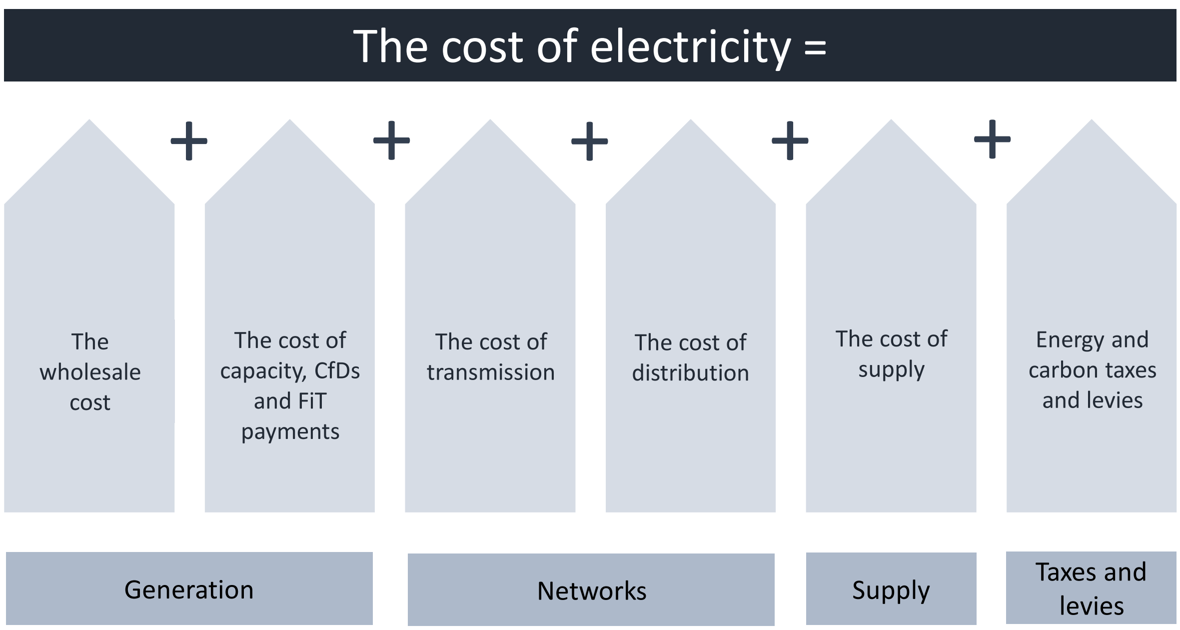
38. Ofgem states that the £19 fall for electricity has been driven by lower forecast costs in supplying electricity to PPM customers. Wholesale electricity prices for delivery this coming winter and next summer have fallen. Costs to consumers from the government's capacity market auction will also be lower than projected for the previous cap, reflecting the outcome of the auction earlier this year. Other policy costs for 2017/18 are unchanged. Note that in the same period there has been no comparable fall in the SVT.

39. In addition to generalising the detail in the PPM cap by extending caps to other groups, this approach suffers from two problems: it leaves out lots of customers suffering from the excessive charges; and capping the full tariff combines all the other fixed elements with costs controlled by the supplier and reflected in the margin. It therefore needs the regulator to keep adjusting it.

(iii) Provide full transparency through a default tariff, either as a version of a comprehensive SVT cap, or instead

40. The third option is to focus directly on the margins, and the costs the suppliers actually control. There will always have to be a default tariff for those with better things to do than trawl the internet trying to comprehend the myriad ‘deals’ and ‘offers’. Recent moves by some of the Big Six to ‘abolish’ SVTs miss the point – they are just going to move from one default tariff (the SVT) to another. They cannot simply disconnect customers who take no action – and if they did there would be a justified outcry. However defined, that tariff will always need to reflect the costs of the full supply chain. If it does not, someone else will have to pay more to compensate or there will be excess returns.

41. The default tariff is one that incorporates all the costs of energy as set out in this review – just as price caps will need to do. These are as follows.



42. The generation cost can be an index of actual wholesale prices, revised at regular intervals with an error correction. The rest of the costs are system costs, with the exception of the supply margin. Again, an error correction can be applied to eliminate supplier risk – and the extra costs of a higher margin to compensate for the risk. In the default tariff I recommend, these exogenous elements are automatically adjusted, with suppliers responsible for accurately reflecting and reporting how the cost pass-throughs are adjusted, and with error-correction mechanisms.

43. The form of the default tariff could be set by Ofgem and would set out these elements transparently, and in particular identify the margins explicitly. These margins – the only difference that suppliers can offer within this default tariff – should be published on Ofgem's website. Competition in this framework is about the margins. Any supplier has to offer this tariff, and hence customers simply need to select the lowest offered margin. It is simple, transparent, and pro-competition.

44. Margins competition offers two further benefits:

(i) It encourages new entrants, and especially those offering bundled services. New technology may bring players from outside the industry – the coming of car companies, Amazon, Google, BT and Sky and other household services companies are possible examples. They do not need, under the default tariff, to set up complex business models for the exogenous parts of the tariff, and particularly for the index of wholesale costs.

(ii) It leaves open the allocation of the fixed costs between the customer classes. This is where poverty and industrial tariffs come into play, where government has a key role to play, and I make recommendations on this aspect in section 10.

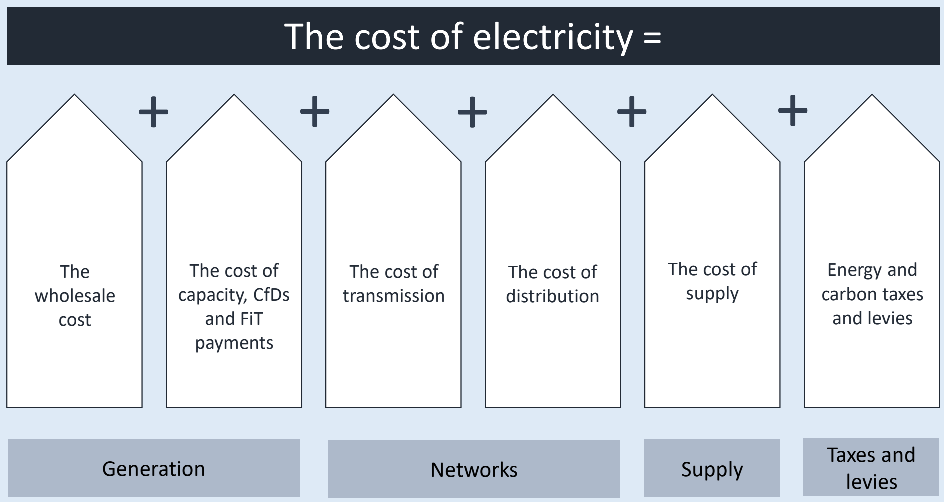
45. The main objection to my default tariff is that it is claimed that it will inhibit competition. The case for inaction, the Austrian view, is that fat profits are needed to encourage entry. The trouble with this is that it requires customers to pay excessive costs in the interim until the arrival of a fully competitive market. It is the same argument against interventions in the transmission and distribution price caps. It also assumes that a fully competitive market will arrive *automatically*. By focusing on any fat margins that exist, the default tariff will accelerate, not impede, the development of competition. In a competitive market, margins (and the prices of supply) will converge on the competitive margins and prices. There will be no incentive to increase margins. Contrary to certain comments from some of the companies, price divergence for a homogeneous product is not an obvious feature of a competitive market.

46. The government is introducing legislation for a comprehensive price cap for all SVT customers. This can be based on the default tariff I recommend. The cost pass-through elements would be defined as in the PPM cap and the Northern Ireland supply price control, as would the margin. The difference between the default tariff and these other examples is that the cost pass-through elements would be automatic and the margins explicitly focused upon. In implementing the new legislation, Ofgem should therefore focus its price cap proposals on a maximum margin within the default tariff I

recommend, leaving headroom for competitors to offer lower margins, or indeed any other tariffs that they may seek to offer to customers.

MAIN FINDINGS AND RECOMMENDATIONS

- There should be a default tariff as follows.

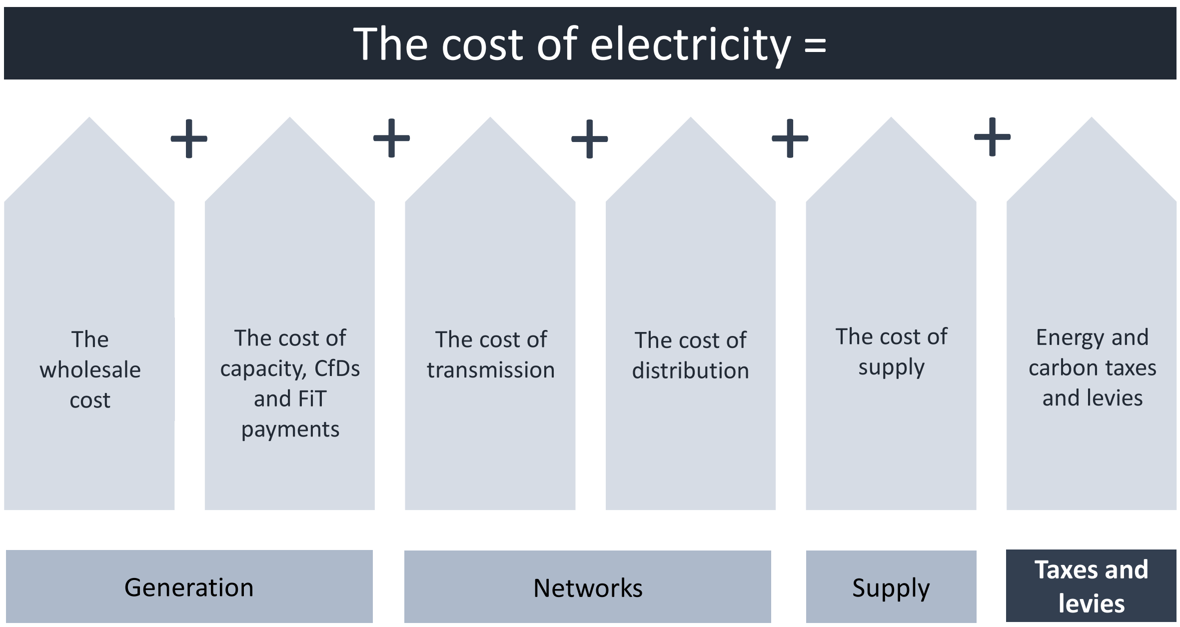


- The legacy costs should be clearly and separately identified on bills (see section 5).
- The supply margin should be published, so that customers and entrants can easily see the costs of supply that the supplier controls.
- In implementing new legalisation for a more comprehensive price cap to protect SVT customers, Ofgem should focus on setting a maximum supply margin, leaving the companies and entrants free to offer customers lower margins and any other tariffs they choose. The rest of the price cap can incorporate the other elements of the default tariff.
- To reduce the risks to suppliers, there should be explicit error-correction mechanisms in the default tariff.

10. Energy Taxes, Carbon Prices, Levies, and Regulations

This section addresses:

- **energy taxes and carbon pricing**
- **sorting out the different types of levy**
- **the social levies and how they relate to fuel poverty**
- **energy efficiency levies**
- **whether industry should have explicit mechanisms like the CCL**
- **dealing with social issues through the allocation of fixed system costs**



1. In addition to the costs of generation, capacity, FiTs, CfDs, transmission, distribution and supply, households and industry pay a complex variety of energy taxes, carbon prices, and other levies. Each of these interventions has been developed in an *ad hoc* way, and little serious thought has been given to how they fit together, and whether they comprise a cogent approach to general taxation and correcting market failures, or whether households and businesses can afford to pay for them. They are silo measures, and in any long-term framework there is great scope for considerable simplification and improvement.

2. In considering these interventions, there are two questions which are crucial yet rarely asked:

- What are the objectives which the taxes and other measures are designed to achieve?
- What is the economic incidence of each of the measures?

3. The general tax objective is the first and main reason that energy taxation has developed over the last century. There is a general case for taxing inelastically demanded commodities as part of an overall tax regime, and its efficiency properties derive from the Ramsey principle of minimising distortions previously discussed in section 3, and hence the inefficiencies they might cause. The more inelastic the demand, the fewer changes in behaviour there will be. A tax is just a change in price, and it has income and substitution effects like any other price change. For general taxation, the aim is to minimise the substitution effect and maximise the income effect. For market failure taxation, like carbon, it is the opposite.

4. The principle behind VAT is somewhat different. The general principle is that all consumption is taxed at a uniform rate, irrespective of the different elasticities. As a general tax on consumption, there are few reasons why there should be any VAT exemptions in energy, other than political considerations.

5. The second reason for taxing (and subsidising) energy is to correct market failures. The most important of these is carbon: its reduction is one of the core objectives of energy policy, as set out in section 2. Since carbon emissions have the same impact wherever they are emitted, there should in principle be the same price of carbon in every sector, and globally. This is the most efficient policy instrument to internalise the carbon externality. It allows the markets to sort out which reductions in carbon can be achieved at lowest costs – whether in agriculture, buildings, transport or energy, and whether in China, Argentina or the UK. Any other approach is very likely to mean higher costs for any given carbon target, and hence in a least-cost long-run framework, the price of carbon has a central role to play. A carbon price is also the simplest: it does not involve the government doing very much else to meet its targets (except for R&D and innovation), and it is a key way to cut through the thicket of current multiple interventions.

6. In the UK case of a unilateral carbon production target, a carbon price remains the most efficient solution, although account will need to be taken of the border carbon price since it is on production and not consumption. It is extremely important to bear in mind that not to have an explicit carbon price, and to use second-best policies, does not mean that there is no price effect, or border price effect. *There is always a carbon cost, and whether it is called a cost or a price is less important*. On the contrary, the implicit price of carbon from the numerous second-best measures identified in section 4 (and the complex web of exemptions to deal with the import competition) is almost

certainly higher, and probably much higher. This additional burden has never been calculated in UK energy policy. I recommend that it should be.

7. A further confusion has been introduced by combining carbon and energy taxation with exemptions for energy efficiency measures. The case for intervening in respect of energy efficiency is distinct and separate, and there have been a number of such direct measures aimed at assumed market failures in the take-up of energy efficiency. The *Clean Growth Strategy* extends these significantly.

8. Taxes, exemptions and subsidies can also be used to achieve distributional ends, charging different prices to different customer groups. It is almost always more efficient to use direct welfare subsidies and supports, rather than distort the prices for carbon and energy directly. However, as the proportion of total costs which are system fixed-costs increases (and are inelastic in demand), there will be greater opportunities for policy to influence their applications, including to industrial customers. As I recommend in section 3, government should consider the long-run pricing issues which arise from a predominantly fixed-cost electricity system.

9. A common mistake is to confuse the formal incidence of a tax with the economic incidence. In the case of business taxes, it is a popular demand that 'business must pay for its carbon emissions'. Facing a common carbon price is the efficient way of achieving this, subject to trade considerations, since the target is unilateral and in production, not consumption.

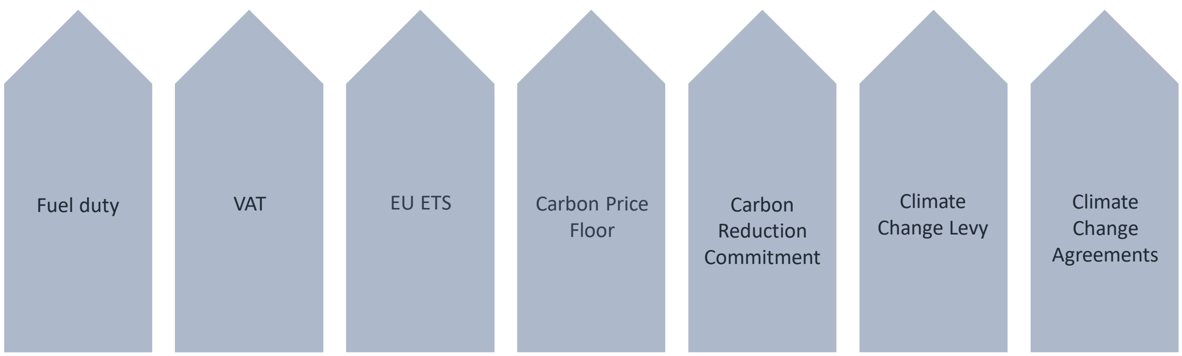
10. But businesses do not in theory pay the economic incidence of taxes: their shareholders and their customers (and sometimes their workers) end up paying. In a competitive market, the economic incidence of carbon taxes and measures like the CCL agreements end up in the prices of the commodities and services that businesses produce, or in a decline in the value of the company if other competitors (including those overseas) do not face the same cost of the taxes. Ultimately, it is individual consumers who create carbon emissions by buying the products that embed them.

11. The economic incidence of the various carbon measures on households is therefore not confined to their electricity and other energy bills. The impacts come in the basket of goods and services they buy and, if they work in internationally traded industries, in their job prospects and pay too. The conclusion is that the cost of decarbonising is not simply the price of the ROCs, FiTs, and low-carbon CfDs and the capacity and networks' additional costs to support the renewables identified in earlier sections. The legacy bank I propose is only a partial measure of the full costs. I recommend that a full audit, including the pass-through of the economic costs of the implicit and explicit prices of carbon in all the goods and services consumed, is conducted for all major policy interventions.

12. A rational first-best energy and carbon taxation regime would have a simple structure: a tax on energy as an inelastically demanded commodity; and a tax on carbon. The current carbon taxation regime, explicitly and implicitly, is a long way from this – and therefore imposes (much) higher costs on households and industry for any actual revenue yield and for any carbon reductions which result. The actual regime is complex, multi-interventionist, bureaucratic and, as a consequence, increases the costs of energy. We can do much better.

13. There are seven main and different taxes on energy and carbon, depending on how taxation is defined. Here it is a policy-induced, as opposed to market-induced, change in price. Several of them are of mind-numbing complexity, and these complexities are listed out here, to contrast with the simple uniform carbon price that I recommend. In particular, the exemptions are listed below to show how complicated the actual measures are, and each of these exemptions is subject to lobbying as they create interests and economic rents. The main instruments are as follows.

The explicit and implicit taxes on energy and carbon in the UK



(i) Fuel duty[6]

14. Fuel duty is a levy on fuels, paid by their suppliers and passed through to consumers. It applies to the sale of hydrocarbons used to power engines or other machinery, or for heating.

15. There are a number of exemptions, including:

[6] Sources: https://www.gov.uk/guidance/fuel-duty; https://www.gov.uk/government/publications/excise-notice-183-repayment-of-excise-duty-on-heavy-oil-used-by-growers-of-horticultural-produce/excise-notice-183-repayment-of-excise-duty-on-heavy-oil-used-by-growers-of-horticultural-produce; https://www.gov.uk/government/publications/excise-notice-184a-mineral-oil-put-to-certain-use-excise-duty-relief/excise-notice-184a-mineral-oil-put-to-certain-use-excise-duty-relief; https://www.gov.uk/government/publications/excise-notice-554-fuel-used-in-private-pleasure-craft-and-for-private-pleasure-flying/excise-notice-554-fuel-used-in-private-pleasure-craft-and-for-private-pleasure-flying; https://www.gov.uk/guidance/fuel-duty-reliefs.

- fuel used to produce electricity;
- fuel used for air/marine transport, except for that used in the engines of private pleasure craft;
- fuel used to heat buildings used for horticulture;
- unleaded petrol or diesel sold for road fuel on remote islands;
- light and heavy oils used for some industrial purposes;
- 'red diesel' or gas oil appropriately marked as such used for non-road-fuel purposes (such as agricultural equipment) or heating.

16. The current rates are as follows.

TABLE 24: CURRENT RATES OF FUEL DUTY

Fuel type	Rate (£/litre)
Unleaded petrol	0.5795
Heavy oil (diesel)	0.5795
Biodiesel	0.5795
Bioethanol	0.5795
Aviation turbine fuel used for private pleasure flying	0.5795
Light oil (other than unleaded petrol or aviation gasoline)	0.6767
Aviation gasoline (Avgas)	0.3770
Light oil delivered to an approved person for use as a furnace fuel – includes rebates	0.1070
Marked gas oil – includes rebates	0.1114
Fuel oil – includes rebates	0.1070
Heavy oil other than fuel oil, gas oil or kerosene used as fuel	0.1070
Kerosene to be used as fuel in an engine, other than in a road vehicle or for heating – includes rebates	0.1114
Biodiesel for non-road use – includes rebates	0.1114
Biodiesel blended with gas oil for non-road use – includes rebates	0.1114
Aqua methanol	0.0790
Road fuel natural gas, including biogas	0.2470
Road fuel gas other than natural gas – eg, liquefied petroleum gas (LPG)	0.3161

Source: BEIS.

Notes: The amount of tax levied does not relate to the carbon content of the fuel. Taxes on petrol have been part of the UK fiscal landscape since 1908.

(ii) VAT[7]

17. VAT is a tax charged as a percentage of the value of the goods supplied. It is a percentage of the total cost of energy, and therefore is not proportionate to carbon emissions.

18. It is applicable to fuels and power, and in particular to all fuels sold for consumption, including transport fuels, fuels for heat and/or electricity production, electricity, and heat vectors such as steam. The CCL charge for a given fuel, if applicable, is included in the value of that fuel for VAT purposes.

19. There are a number of exemptions:

- domestic users and charitable organisations are liable for a reduced rate of VAT (5%) on their fuel and power purchases;
- this reduced rate also applies to *de minimis* supplies of electricity, gas, solid fuels and LPG;
- the replacement and/or repair of dangerous, obsolete or inefficient appliances after the electricity or gas meter under a statutory obligation is not eligible for VAT.

(iii) EU ETS[8]

20. The EU ETS was launched in 2005 as a market-based, carbon-pricing system. It is not explicitly a tax, but it yields a carbon price and, as noted above, a tax is a policy-induced change in price and so it is treated here under the general tax heading.

21. The EU ETS sets a total cap on the amount of certain GHGs that can be emitted by factories, power stations and other installations in the system. Within the cap, participants receive or buy emission allowances. The system allows trading and the carbon market to determine the cost of the allowances (carbon price).

22. The EU ETS applies primarily to all power generation and heavy industry in EU member states, plus Norway, Lichtenstein and Iceland. More specifically, Phase III (2013-20) includes any installation where fuel (other than 97% or more biomass) is burned in a combustion unit of 3MW or above for whatever purpose and which, when aggregated, exceeds 20MWth input. Where the 20MW threshold is exceeded, all combustion units are captured by the EU ETS. It includes electricity

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[7] Source: https://www.gov.uk/government/publications/vat-notice-70119-fuel-and-power/vat-notice-70119-fuel-and-power.

[8] Source: https://www.gov.uk/guidance/participating-in-the-eu-ets.

generation and the main energy-intensive industries such as: iron and steel; mineral-processing industries such as cement manufacture; pulp- and paper-processing industries; glass; and chemicals. There are around 900 such installations in the UK.

23. The ‘cap’ will decline by 1.74% per year to 2020 (and more steeply after that), so that emissions in 2020 will be at least 21% below 2005 levels.

24. Some other large non-industrial installations also meet these criteria and are covered by the EU ETS. Most aircraft travelling between airports within the EU are also included in the EU ETS.

25. There are lots of exemptions and complexities. In the current phase of the EU ETS, the vast majority of energy-intensive industry sectors – representing around 97% of industrial emissions – have been deemed at risk of carbon leakage. In order to mitigate this risk, the sectors in question are entitled to a fixed 100% of free allowances (to the sector benchmark set by the top 10% most efficient installations) to reduce their carbon costs. However, this entitlement can be impacted by the application of the Cross-Sectoral Correction Factor (CSCF) (see below).

26. The high number of sectors deemed at risk of carbon leakage under the current assessment criteria has led to the introduction of the CSCF, which removes free allocation by a fixed percentage from all installations regardless of their risk in order to keep the total amount of free allocation below the maximum level. The result of this is a risk that those installations which are genuinely exposed to carbon leakage might receive less support than they need. However, this measure guarantees that the cap on free allocation is not exceeded.

27. In the UK and some other member states, there is also a small emitter opt-out scheme, whereby small emitters can opt out of the full EU ETS as long as they pay an equivalent carbon price for their emissions through a simpler system.

28. The ‘cap’ is converted into allowances, known as EUAs (1 tonne of CO_2 = 1 EUA). Each ETS allowance gives the holder the right to emit 1 tonne of CO_2. Each year installations within the scheme must surrender allowances for every tonne of CO_2 emitted in the previous year. The cost of 1 EUA can vary significantly according to market fluctuations, and in recent years the price has been low due to the surplus of allowances which has built up in the system.

29. As the graph below shows, the EU ETS price performance has been volatile and has produced a low price – so low in fact as to have little or no impact on business investments. Over the past couple of years the price has hovered between €5 and €8 per allowance. The scheme has been riddled with

problems, including some corruption, and created substantial costs in its functioning. With the development of a separate renewables policy alongside the EU ETS, reductions in carbon due to renewables have created space within the EU ETS to expand emissions, and still meet the overall EU carbon target for 2020. Most of this expansion has been coal.

30. Measures are under negotiation which would strengthen the carbon price for Phase IV of the EU ETS 2021–30 (which the UK supports). The relevance of these depends on the outcome of the Brexit negotiations, and whether the UK remains a member of the EU ETS post-Brexit.

31. The gases included are:

- CO_2 from power and heat generation, and from energy-intensive industry sectors including oil refineries, steel works and production of iron, aluminium, metals, cement, lime, glass, ceramics, pulp, paper, cardboard, acids and bulk organic chemicals, and commercial aviation;
- nitrous oxide from production of nitric, adipic and glyoxylic acids and glyoxal;
- perfluorocarbons (PFCs) from aluminium production.

FIGURE 40: EU ETS ALLOWANCE PRICES: MONTHLY AVERAGE FRONT YEAR EUA FUTURES PRICE (€/tCO_2)

Source: Intercontinental Exchange (ICE).

Notes: Phase 1 EUAs trended to zero at the end of the phase as EUAs issued under it were non-transferable to later phases.

(iv) Carbon Price Floor[9]

32. Recognising these flaws in the EU ETS, and taking account of the unilateral carbon targets that were adopted under the CCA, the government then introduced a UK-only floor price of carbon (CPF). Unlike the EU ETS, the CPF has been highly effective and has gone a considerable way to making a reality of the commitment to eliminate coal by 2025 from the electricity generation mix.

33. The CPF, introduced in April 2013, is made up of the price of CO_2 from the EU ETS and the Carbon Price Support (CPS) rate per tonne of CO_2, which is the UK-only additional tCO_2 emitted in the power sector. Gas and coal generators pay the CPS on top of EU ETS costs. It therefore differs significantly from the pure EU carbon price regimes.[10]

34. The current rate is £18/tonne of CO_2 generated. The tax is capped at this figure until the financial year 2019/20. The CPF is based on tonnes of CO_2 generated. The Spring Budget 2017 stated the following:

> *The government remains committed to carbon pricing to help decarbonise the power sector. Currently, UK prices are determined by the EU Emissions Trading System and Carbon Price Support. Starting in 2021–22, the government will target a total carbon price and set the specific tax rate at a later date, giving businesses greater clarity on the total price they will pay. Further details on carbon prices for the 2020s will be set out in the Autumn Budget 2017.*

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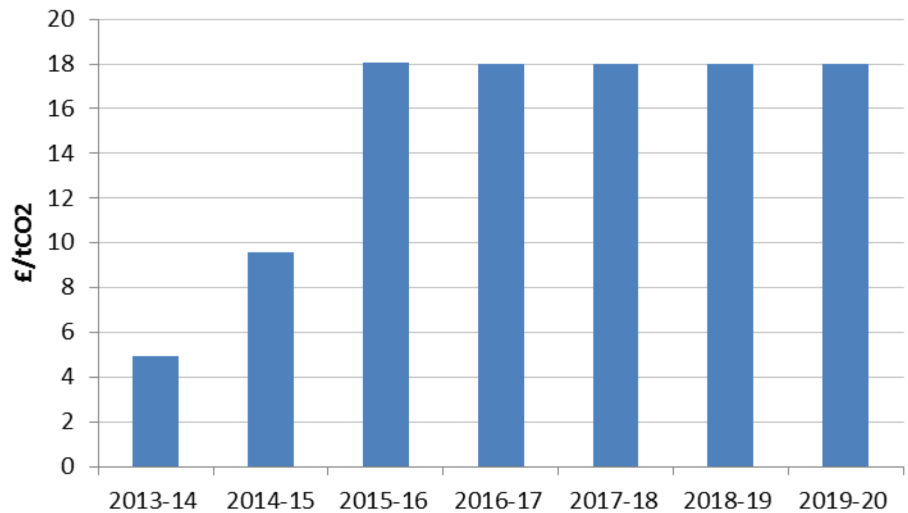
[9] Source: https://www.gov.uk/government/publications/excise-notice-ccl16-a-guide-to-carbon-price-floor/excise-notice-ccl16-a-guide-to-carbon-price-floor.

[10] Carbon Price Support is not levied in Northern Ireland.

FIGURE 41: RATES OF CARBON PRICE SUPPORT



Source: HMRC (2017), 'Climate Change Levy and Carbon Price Floor Bulletin', available at https://www.uktradeinfo.com/Statistics/Pages/TaxAndDutybulletins.aspx; HMRC (2014), 'Carbon Price Floor: Reform and Other Technical Amendments', available at: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/293849/TIIN_6002_7047_carbon_price_floor_and_other_technical_amendments.pdf.

Note: In 2020–21 the government is maintaining the cap on CPS rates at £18 t/CO_2, uprating this with inflation (HM Treasury (2016) Budget 2016).

35. There are exemptions. The government reimburses electricity-intensive companies to compensate for the impact of the CPS on the electricity prices they pay, on the same basis as relief for the indirect impacts of the EU ETS on electricity costs. BEIS manages this compensation scheme, which (along with EU ETS compensation) is expected to cost over £300m/year by 2020. Fuel used in CHP plants that meet the required quality standard is exempt from the CPF.

(v) CRC[11]

36. The CRC Energy Efficiency Scheme (formerly known as the Carbon Reduction Commitment) was introduced by the UK government in 2010. It is designed to improve energy efficiency and cut CO_2 emissions in private and public sector organisations that are high energy users. The CRC is based on CO_2 (equivalent) emissions from gas and electricity supplies.

[11] Source: https://www.gov.uk/government/collections/crc-energy-efficiency-scheme.

37. Some public bodies must take part in CRC regardless of how much electricity they use. These are called mandated participants and they include all UK central government departments and devolved administrations.

38. CRC operates in phases. Phase I ran from April 2010 until the end of March 2014. We are now in Phase II, which runs from 1st April 2014 to 31st March 2019, and its closure has been announced after the current phase (subject to devolved administration agreement).

39. There is a qualification year for each phase. The qualification year for Phase II was between 1st April 2012 and 31st March 2013. In each compliance year, an organisation that has registered for CRC needs to:

- collate information and submit a report about its energy supplies;
- buy and surrender allowances equal to the CO_2 emissions it has generated;
- inform the Environment Agency of any changes to its organisation that could affect its registration (designated changes);
- keep an evidence pack of records about its energy supplies and organisation.

40. There are exemptions. Energy already covered under CCAs and the EU ETS is not included in CRC; and businesses with less than 6,000MWh of electricity demand are outside the scope of the CRC.

41. In the current phase, participants have the option of buying allowances in advance in the lower-price 'forecast sale' at the start of a compliance year, or in a higher-price 'compliance sale' after the end of the year.

42. For the current phase, the following prices have been announced.

TABLE 25: CURRENT CRC PRICES

CRC scheme year	Forecast sale price	Compliance sale price
2014/15	£15.60	£16.40
2015/16	£15.60	£16.90
2016/17	£16.10	£17.20
2017/18	£16.60	£17.70
2018/19	£17.20	£18.30

Source: BEIS.

(vi) Climate Change Levy[12]

43. The CCL, introduced in 2001, is a tax on energy delivered to non-domestic users in the UK. Its aim is to provide an incentive to increase energy efficiency and to reduce carbon emissions.

44. It has a cross-sectoral application. Businesses in the following sectors pay the main rates of CCL:
- industrial;
- commercial;
- agricultural;
- public services.

45. There are exemptions on the main rate of CCL on certain suppliers to classes on energy users:
- businesses that use small amounts of energy;
- domestic energy users;
- charities engaged in non-commercial activities.

46. Electricity, gas and solid fuel are normally exempt from the main rates of CCL if any of the following apply:
- not used in the UK;
- if supplied to or from certain CHP schemes registered under the CHP Quality Assurance Programme;
- if the electricity was generated from renewable sources before 1st August 2015;
- if used to produce electricity in a generating station which has a capacity of 2MW or greater;
- not used as fuel;
- used in certain forms of transport.

47. There is a reduction in the main rates of CCL for energy-intensive businesses that have entered into a CCA with the Environment Agency. Energy-intensive businesses can get a 90% reduction for electricity and a 65% reduction for gas, LPG, coal and other solid fuel. These agreements yield another layer of regulation and administration.

48. The current CCL rates are set out below.

[12] Source: https://www.gov.uk/green-taxes-and-reliefs/climate-change-levy.

CURRENT CCL RATES

RATE FROM 1ST APRIL 2017–31ST MARCH 2018
Electricity (£/kWh): 0.00568
Natural gas (£/kWh): 0.00198
LPG (£/kg): 0.01272
Any other taxable commodity (£/kg): 0.01551

RATE FROM 1ST APRIL 2018–31ST MARCH 2019
Electricity (£/kWh): 0.00583
Natural gas (£/kWh): 0.00203
LPG (£/kg): 0.01304
Any other taxable commodity (£/kg): 0.01591

RATE FROM 1ST APRIL 2019–31ST MARCH 2020 (THIS RATE INCLUDES THE UPLIFT FOR CRC CLOSURE)
Electricity (£/kWh): 0.00847
Natural gas (£/kWh): 0.00339
LPG (£/kg): 0.02175
Any other taxable commodity (£/kg): 0.02653

Source: BEIS.

(vii) Climate Change Agreements[13]

49. CCAs, introduced in 2013, are a voluntary scheme that allows energy-intensive participants in 53 sectors to pay significantly reduced main rates of CCL in exchange for signing up to energy efficiency or carbon reduction targets. Hence it is in effect a tax exemption mechanism. Since it is voluntary, exemptions are not applicable.

50. The current scheme ends in March 2023 with energy targets set to the end of 2020.

51. Currently there is a buy-out element in the scheme whereby if a party does not meet its carbon-saving target it has to pay £12/tonne of CO_2e emitted over its target. Government consulted in 2016 to increase the buy-out to £14/tonne of CO_2e in line with RPI for target periods 3 and 4 (2017–20). A statutory instrument has been laid to provide for the new buy-out price.

52. CCAs are available for a wide range of industry sectors, from major energy-intensive processes such as chemicals and paper, to agricultural businesses such as intensive pig and poultry farming.

[13] Source: https://www.gov.uk/guidance/climate-change-agreements--2.

The case for tax simplification and harmonisation

53. The general taxation of energy is one part of the overall tax regime. It is not hard to describe a general optimal tax regime, which can be applied to energy. The key points are: there should be as few exemptions as possible; and if there are exceptions and different rates, these should be related to the elasticities.

54. A review of energy tax for a long-term framework will be forced on government in any event. The switch to EVs and the increases in fuel efficiency will erode the fuel tax yield, and consideration will have to be given to how to replace the revenue forgone. Beyond VAT, the government will not have a significant general tax yield without reform in the new emerging electricity and energy model I set out in section 11.

55. The case for harmonisation and universalisation of the carbon price is overwhelming. A uniform carbon price would:
    - provide common incentives across the economy, and bring in the agricultural, buildings, transport and other sectors fully onto the path to decarbonisation;
    - allow the market to find the least-cost solutions, rather than the CCC and government trying to forecast and model what these might be;
    - facilitate the abolition of the other tax measures;
    - greatly simplify the administration and regulatory burdens;
    - allow for specific measures to be aimed at energy efficiency;
    - raise significant revenue, including compensating for the loss of fuel duty.

56. Tax harmonisation is essential if the overall interventionist regime is to be simplified and a greater role in decarbonisation passed back to the market.

57. There are two ways of approaching carbon price and energy tax harmonisation: via a generalisation of fuel duty; or via the CPF and CPS.

58. In the fuel duty case, there could be an extension to include coal, oil and gas used throughout the economy. In principle, there might be three general rates for the three main fossil fuels, cutting through the complexity of the current scheme described above. In practice, this would require some further adjustments, but the key point is to move from a focus on roads and vehicles to one on a general tax. The weights for each of the three main fuels could be related to their carbon intensity.

This would encourage a switch between the fossil fuels, and between them and renewables, nuclear and other low-carbon options.

59. An alternative and potentially better route would be to generalise the CPF and CPS beyond the power sector to include all the other sectors in the economy. This would also lend itself to a border adjustment, applying the harmonised carbon price to imports from non-carbon-priced countries of origin, and exempting exports to countries without appropriate carbon prices.

60. The CPF and CPS do not currently apply to imported electricity through the interconnectors, and hence discriminate against domestic electricity generation. There are complications in extending it – notably the variable supplies – although these are not insurmountable. This is one further example of the need to apply the carbon price at the border.

61. The more general criticism is over the practicality of a border carbon price. But this is typically based on a claim about perfecting the measurement of all goods and services in continuous time, and the consequent large data flows required. Yet VAT adjustments already apply across borders and there are in practice a small number of key industries that are responsible for the bulk of carbon imports. It is a case of being practical and roughly right, versus being exactly wrong, and as a consequence having to develop a complex web of exemptions and subsidies to compensate for this.

62. It is further argued that the CCL has the advantage of capturing imported and domestic carbon because it is a downstream tax. This is a very poor argument since it does not address carbon directly, and is a catch-all to try to patch up the impartial coverage of carbon taxation elsewhere, and has multiple objectives beyond the carbon price – being both a way of compensating large companies exposed to international competition and promoting energy efficiency. It also requires its own calibration, which in turn requires a judgement about import competition, and hence does not escape the data problems identified above with a border carbon price.

63. It is notable that, in considering the various measures above, the range of carbon prices is quite narrow – between about £12 and £18/tonne CO_2e.

64. As part of a development of a long-term framework, I recommend that the Treasury carry out an audit of the costs of the complexity of the current energy and carbon tax instruments and consider the two options above for harmonising the carbon price across the economy.

Direct regulation of emissions

65. Direct regulation of emissions has worked alongside the CPF to undermine the economics of coal stations and bring forward their closure. It has an implicit price, and hence should be viewed alongside the explicit policy-induced changes in prices above.

66. The EU National Emissions Ceiling Directive sets a total emission ceiling for key air pollutants (sulphur dioxide, nitrogen oxides and dust (particulate matter)) which must be met from 2010 in the UK. A revised National Emissions Ceiling Directive that sets stricter emissions ceilings for 2020 and 2030 was adopted in 2016. Meeting these new ceilings is expected to require further action from all parts of the economy.

67. The Industrial Emissions Directive (IED)[14] came into force on 6th January 2011, and into effect in 2016 in relation to existing large combustion plants, and sets new emissions limits for key air pollutants. Three compliance options are available to plants:

   - To meet the emission limit requirements from 1st January 2016. Compliance is estimated to require investment of the order of £50m–£75m/500MW unit.
   - To participate in the Transitional National Plan, which allows certain older plants until July 2020 to meet the emission limit requirements described above. Plants in the Plan are subject to an annual emissions allocation within a declining overall UK maximum emissions ceiling. By July 2020 they must either meet the emission limit requirements, close, or continue to operate with a higher emissions limit but limited to 1,500 hours per year (ie, 17% annual load factor).
   - To utilise the Limited Lifetime Derogation, which limits plants to 17,500 hours of operation between 1st January 2016 and 31st December 2023, after which they must close.

68. The majority of remaining coal stations are participating in the Transitional National Plan and therefore have until mid-2020 to install the equipment needed to meet the emission limit requirements, close, or be limited to 1,500 hours a year (which may still require some investment to reduce emissions).

69. As part of the IED, large combustion plants must also apply Best Available Techniques (BAT). BAT is the concept used to identify the most effective technologies for reducing emissions of pollutants from industrial processes, including power generation.

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[14] See http://ec.europa.eu/environment/industry/stationary/ied/legislation.htm for more information on the IED.

70. The IED superseded the Large Combustion Plant Directive in 2016. The latter was an EU directive aimed at controlling emissions of sulphur dioxide, nitrogen oxides and particulate matter from plants rated over 50MW (thermal). Existing plants licensed before 1987 had three options:

- meet new emission limits which will require retrofitting of flue gas treatment equipment;
- opt-out limited-life derogation: 20,000 hours of operation between 1st January 2008 and 31st December 2015;
- close before 1st January 2008.

71. For new fossil fuel plants, an Emissions Performance Standard, as set out in the Energy Act 2013, applies to generating stations that are above 50MWe. It works on a 'mass basis' and sets an annual limit on emissions at a level equivalent to 450gCO_2/kWh for a plant operating at baseload. This is around half the level of emissions of unabated coal generation and is fixed until the end of 2044.

72. These are very much second-best approaches, through regulation rather than pricing. Once in this second-best world, it is worth considering the other direct regulation options, of which mandated closure of coal power stations could have a significant role to play. The case for a fast-track closure of coal is considerable – it produces multiple emissions, from particulates to methane, and carbon, and damages the health of those in the industry who inhale the coal-polluted air. Much of the above direct regulation could have been cut through by a defined coal closure plan.

73. The government has used the mandatory regulatory approach in its announced phase-out by 2040 of petrol- and diesel-only cars. The advantage of this sort of direct regulation is that it could facilitate a coordinated roll-out of the infrastructure to make EVs function effectively over the period, as discussed in section 6.

74. There is a high economic value in coordination from an element of policy certainty. In both the coal phase-out by 2025, and the diesel and petrol car phase-out by 2040, future governments may change their minds. To pre-empt this, and hence hold down the cost of capital for infrastructure and other investments which might otherwise become stranded, I recommend that the government consider legislating to prohibit coal generation from 2025 and diesel- and petrol-only car sales from 2040.

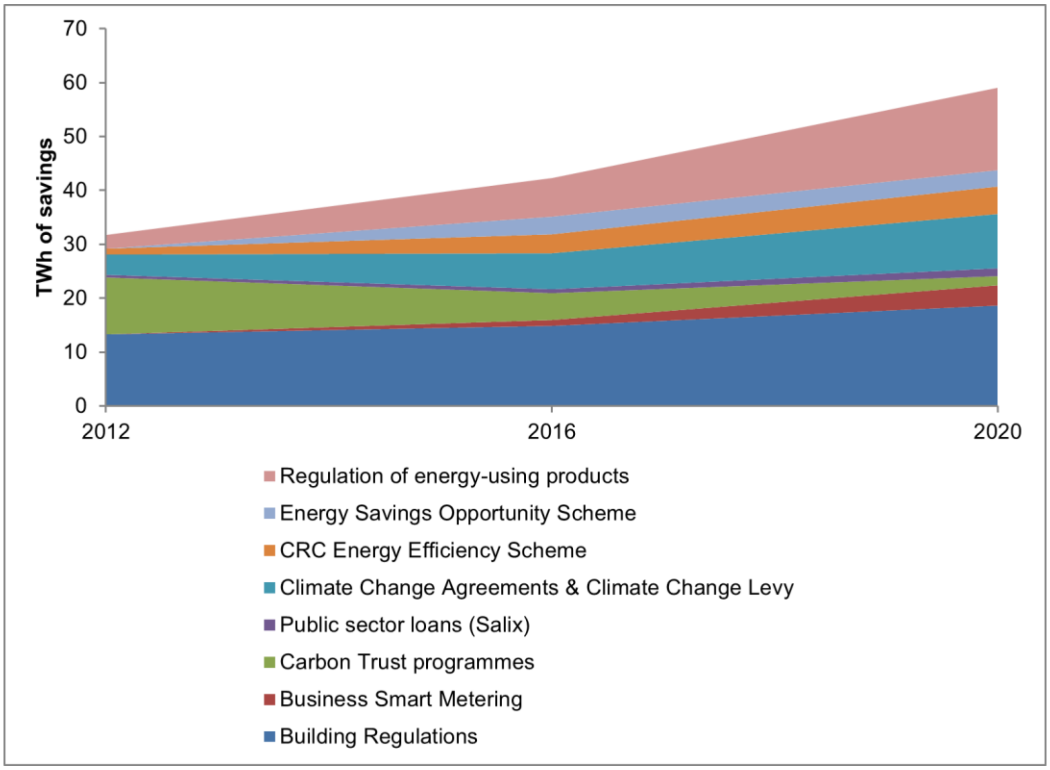
Other levies and costs: energy efficiency measures

75. To the immense complexity of the taxes and direct regulations are added a number of explicit and implicit levies and costs that fall on energy consumers, notably from the various energy efficiency

programmes and the smart meter roll-out. These are partly for the business sector, and partly for the domestic sector, though recalling the economic incidence discussion above, all of these costs and levies ultimately fall on consumers, workers and shareholders.

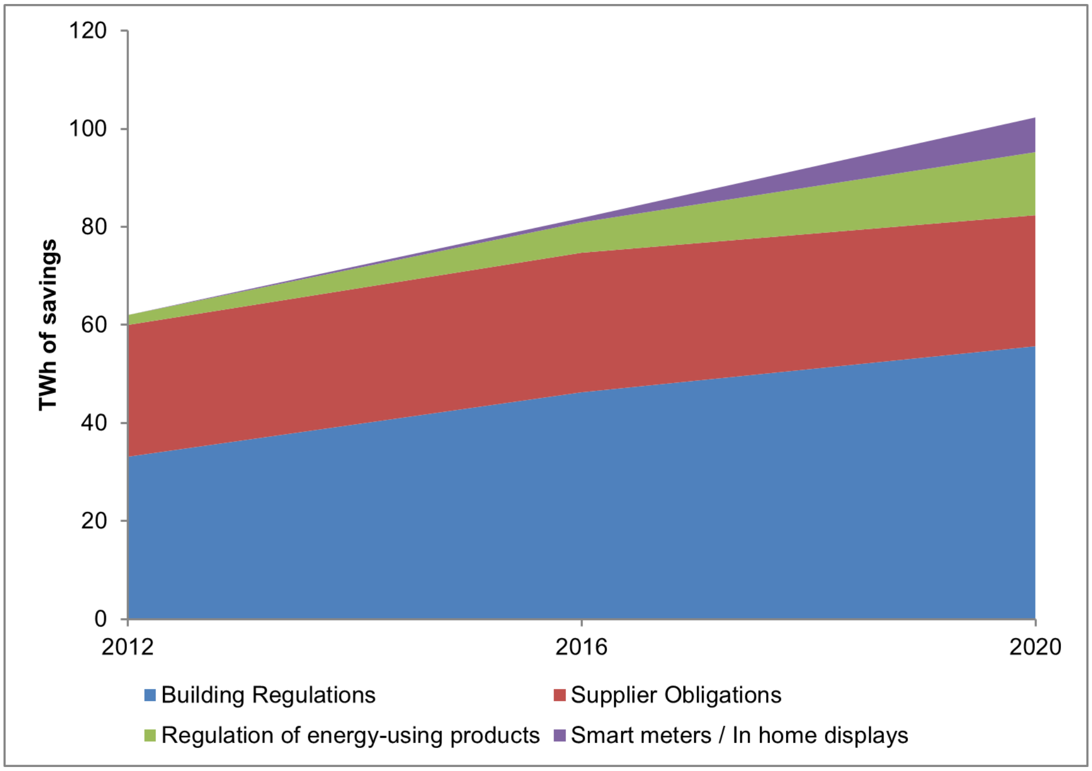
76. The chart below illustrates the UK's energy efficiency policy landscape, excluding transport, and how it is entwined with the energy tax system. Building and product regulations dominate. Their expected impacts on energy saved are set out below. The sheer scale and complexity, and their overlaps, is beyond the scope of this review.

FIGURE 42: ENERGY EFFICIENCY POLICIES IN THE NON-DOMESTIC SECTOR



Source: UK National Energy Efficiency Action Plan, 28th April 2017, available at https://ec.europa.eu/energy/en/topics/energy-efficiency/energy-efficiency-directive/national-energy-efficiency-action-plans.

FIGURE 43: ENERGY EFFICIENCY POLICIES IN THE DOMESTIC SECTOR



Source: UK National Energy Efficiency Action Plan, 28th April 2017, available at https://ec.europa.eu/energy/en/topics/energy-efficiency/energy-efficiency-directive/national-energy-efficiency-action-plans.

77. There have been numerous energy efficiency schemes, from the CCL and CCAs through to the ECO for domestic customers.

78. The ECO is a supplier obligation which began in 2013, replacing earlier schemes. Government sets targets for the delivery of energy efficiency measures in homes that energy supply companies then have to meet. The companies recover the costs of installing measures from all their customers.

THE ECO

The scheme, as extended from April 2017, requires suppliers to meet two targets before the end of September 2018. One (30% of the spend envelope) requires them to install energy efficiency measures in any home in order to achieve carbon savings at least cost. The other (70% of spend), while still achieving carbon savings, specifically requires them to install energy efficiency measures in a defined group of low-income homes (those otherwise unlikely to be able to pay) in order to reduce their energy costs. Of this group of low-income homes, an estimated 34% are living in fuel poverty – others are still low-income households struggling with the cost of keeping warm.

Further details are available at: https://www.gov.uk/government/news/more-people-to-receive-help-to-stay-warm-in-their-homes-thanks-to-new-energy-reforms. This includes January's announcement on the current ECO scheme and also the government consultation response.

	2013	**2014**	**2015**	**2016**
Total delivery and administrative costs	£1,132m	£1,327m	£540m	£511m

Source: https://www.gov.uk/government/statistics/household-energy-efficiency-national-statistics-headline-release-september-2017.

There are a number of reasons for the changing profile:

- The ECO was launched with assumed costs from the targets on suppliers of £1.4 billion per year, but there was an early policy decision to change this and a quick reduction of more than £0.5 billion. The Spending Review 2015 then set a lower annual cost profile of £640 million per year from 2017 to 2022.
- Contractors are not required to work to annual spending budgets. They have longer periods to deliver the targets they are set, and this flexibility can result in bunching of delivery.

The assumed annual cost of the current ECO scheme from April 2017 to September 2018 is £640 million. That results in a cost on bills of £27 per year. However, savings from the energy efficiency measures installed will continue over the lifetime of those measures which will be 30–40 years for insulation. BEIS claims that, in looking at the current ECO in isolation (ignoring the costs and benefits of previous and future supplier obligations), it will generate an average saving across all bills of nearly £10 per year from October 2018 from the £41 cost on bills over 18 months.

Source: BEIS.

79. The obvious question is why the costs of the ECO should fall on all customers when only some customers benefit, given that this is not the case for the Green Deal. This is further complicated by the fact that the ECO is to a significant extent less a pure energy efficiency measure and more a fuel poverty one. If maximising energy efficiency was the policy objective, it would probably be better to start with large houses and buildings, since small accommodation individually typically has quite low energy consumption, even if it is inefficient. In a general tax system, the principle of separating out efficiency from distribution translates into problems for welfare and welfare spending, and

those of addressing market failures. In the long-term framework, if energy policy is to be used as a means for distributional ends it should be made transparent. I recommend in the default tariff that the ECO is clearly identified on customers' bills.

80. The overall problem with energy efficiency issues is that they confuse market failures, and the appropriate market failure interventions, with levies, *and* they confuse energy efficiency with fuel poverty. This is also the case for the CCL and CCAs. The general principles should be: those who benefit should pay; and distributional policies should be directed through general welfare payments, not energy-specific subsidies. The use of standards and the other direct measures in the *Clean Growth Strategy* is a much more focused way of addressing market failures.

Taxation and the industrial sector

81. The various tax and carbon-pricing mechanisms have evolved different, and sometimes overlapping, exemptions and special arrangements for the industrial sector. The result is complex, bureaucratic, and ineffective. As noted, the CCL is a particular example which muddles up energy efficiency policies with trade policies.

82. There are two ways of addressing the industrial competitiveness problem which arises from the unilateral nature of the UK's carbon production target associated with trade with countries without carbon prices. The first is to properly define the affected sectors of the economy and create a set of measurements and weights to calibrate the impacts, and then to extend all exemptions on the same basis. The problem with trying to define which companies are affected is that all are affected once the full economic incidence is considered. All businesses are affected by potential and actual international competition, although they might not realise it.

83. The second is to apply the carbon price at the border. In the presence of a unilateral production carbon target, a border carbon price is the only comprehensive way in which a country can go faster on decarbonisation on a unilateral basis. A border carbon price neutralises the trade effects.

84. Neither of these mechanisms is perfect, and both involve an element of complexity. The border carbon price also raises issues of general trade policy, and World Trade Organization (WTO) rules. As the UK starts to negotiate new trade arrangements post-Brexit, a level playing field involves all countries taking carbon emissions into account on a fair and common basis. Not to have a carbon price is a trade distortion. There is considerable scope to pursue carbon price harmonisation in

these future trade negotiations. The WTO rules in particular explicitly reference environmental measures.

85. Even if the first option continues to be pursued, it can and should be radically simplified.

86. With a proper carbon price in place across the whole economy, there remains a question about the legacy costs identified in section 5. As noted in section 3, industry is already largely exempt from many of the FiT- and CfD-related costs. A simple and effective way of addressing the industrial competitiveness question is to exempt all industry from the legacy costs. These would then either fall exclusively on the domestic sector, or could be securitised and socialised by the government.

87. For future renewables, the long-term framework integrates these into the mainstream through the EFP auctions, and they get the credit for their low carbon emissions through the carbon price. With the gradual abolition of ROCs, FiTs and low-carbon CfD supports, the question of the allocation of this legacy burden gradually diminishes in importance. The option of socialising them always remains.

88. The first-best package for industrial customers therefore contains: a uniform UK carbon price; exemption from the legacy costs; the gradual closure of the CCL and other specific taxes and measures; and a border carbon price. This is the simplest and most competitive framework. Anything else is second-best, and raises the cost of energy for any competitive benchmark.

MAIN FINDINGS AND RECOMMENDATIONS

- The Treasury and BEIS should conduct a detailed review of all the different explicit and implicit carbon prices with a view to identifying major simplifications and harmonisations.
- The Treasury should analyse two possible generalised carbon prices – a generalisation of the fuel duty to all three fossil fuels; and a generalisation of the CPF to the whole economy.
- The government should consider whether a mandatory coal closure programme would be more cost-effective than the various schemes, costs and regulations currently affecting the coal power stations.
- Industry should pay the harmonised carbon price.
- There should be a border carbon price in the context of the CCA unilateral carbon production target.
- The Treasury should consider the general future of the CCL in a long-term framework in the context of a border carbon price.
- Industry should be exempt from the legacy costs.
- Consideration should be given to socialising the legacy costs.
- Energy efficiency should be addressed primarily through standards and other non-tax and non-levy measures.
- The ECO confuses fuel poverty and other welfare and distributional issues with market failures in the take-up of energy efficiency opportunities. It should be explicit in household bills.

PART III

THE WAY FORWARD

11. A Long-term Framework

1. A long-term framework requires a set of principles, an identification of the key parameters, and then a set of policies to achieve the twin objectives of security of supply and the carbon targets. It is a framework that needs to be able to integrate the new and emerging technologies, and it requires an institutional structure within which least-cost solutions can be found in an evolutionary way. In this section I set out each of these components of a stable and efficient long-term framework.

2. At the core of a long-term framework for the electricity industry lie three key design principles, all of which are violated by the current structures. These are:

- simplification rather than ever-greater complexity;
- the assignment of decisions to those best able to make them;
- choosing market prices and auctions wherever possible, over administered decision-making and trying to pick winners.

3. A long-term framework starts with the key parameters:

(i) rapid technological progress, including digitalisation, smart technologies, new storage options, an active demand side, and new materials and advances in basic science (especially for solar);

(ii) electrification of transport;

(iii) the growth of zero marginal cost low-carbon generation and the decline of the wholesale market.

Decarbonisation and the carbon price

4. The least-cost way of achieving the carbon budgets and the carbon targets requires a common carbon price across the economy. Put another way, any other approach raises the costs of meeting the carbon objective. Indeed, there is always a carbon price – the question is whether it is explicit and efficient, or implicit in the myriad technological and other interventions, and inefficient. If the aim is to minimise the cost of energy, then the carbon price has to be explicit.

5. A carbon price is necessary but not sufficient to meet the carbon objectives, since there would also still need to be R&D and innovation measures, and appropriate networks.

6. The case for a common carbon price has long been made and is well researched. It can apply to agriculture, transport and buildings, as well as to electricity generation.

7. With a carbon tax set at the level necessary to achieve the carbon budgets, the market integrates this price, leaving the allocation of resources, and in particular the investment and the operation of the existing systems, to play out.

8. At present, the UK has multiple carbon prices, some explicit and some implicit, as noted in section 10. These include the CPF, the EU ETS price, the CCL implied carbon price, and fuel duty. There are two inefficiencies here: they are inconsistent, causing substitution effects; and none is set relative to the carbon budgets or the 2050 target. In addition, none has an efficient adjustment mechanism.

9. Over time, the government should first harmonise carbon prices and then move to a carbon price that reflects the CCA target. This results in a radical simplification: in addition to replacing the FiTs and low-carbon CfDs, the CCC would no longer need to model different sectors and come up with detailed prescriptions in the carbon budgets. Indeed, in principle, the CCC would need to come up only with the total allowable carbon budget, and nothing much more.

10. A second simplification is that the EFP capacity auction outcomes can be selected on bid prices for decarbonisation purposes, because these endogenise the carbon price. The other relevant functions for selecting outcomes relate to non-carbon issues, such as cyber security and the fuel mix for security of supply reasons, though this too can be reflected in the EFP market design I recommend.

11. Harmonisation and the carbon price-setting and adjustment process raise a number of transitional issues as the existing interventions are revised and brought together. The carbon price can evolve from the current CPF or by moving from a fuel duty to a carbon duty, applying a carbon price to oil, gas and coal inputs. This review does not recommend any detailed tax changes, and each of the existing measures has its own historical rationale.

12. The carbon price for an open economy needs to be applied domestically, and on a similar basis on the border, to avoid offsetting domestic reductions in carbon production by increasing carbon consumption from imports. There is no way around this if the UK is to continue with a *unilateral* carbon production target in the CCA. All the exemptions and special measures to protect industry are substitutes for a carbon price at the border. The simple approach of using a common carbon price both internally and at the border is the most efficient, and all implementation mechanisms need the same informational bases. To gauge how much to subsidise industry is to gauge how big the carbon price effect would be.

Security of supply and the equivalent firm power auctions

13. The problem of security of supply is all about having enough power generation capacity on the system to meet demand. It is about the capacity margin, properly measured. It is about firm power. The rapid development of new DSR options and storage and the impact of EVs change the dynamic of the required margin, and how it is measured. But the basic – and simple – problem does not go away.

14. The private market, left to its own devices, will not deliver a sufficient capacity margin. Security of supply is a system public good and it requires a clear market instrument to deliver it.

15. A single, unified EFP auction delivers security of supply for any given capacity margin for the system as a whole.

16. An EFP auction brings renewables and other capacity together into a single market. It is single (merging the FiTs and CfDs and the existing capacity auctions); it is unified (on the common basis of EFP); and it is a market through which all capacity goes (and hence it is the only way to attain capacity contracts). It is equivalent in that it focuses on the de-rated capacity value to the system of the different forms of generation. As the cost of addressing intermittency falls with DSR and storage, so the de-rating factors lessen.

17. The EFP proposal is a radical departure from the current arrangements. Firm power privatises what is currently government-administered decision-making. Intermittent generators are currently awarded separate FiTs, and do not face the full transmission, distribution and back-up capacity costs they impose on the system.

18. These costs do not go away simply by being disguised within the system. In the current model, the intermittent generators have no incentive to minimise these costs. Indeed, they are so opaque that the exact size and impacts are matters of hypothesis rather than fact.

19. In an EFP single unified auction for capacity, those that cause system costs will have to bear them. Intermittent generators will have to seek contracts to back up their intermittency so they can offer EFP to the system to improve their de-rating factor. They have the advantage of holding better and more detailed information about their technology and costs.

20. The result will be a much enhanced and more efficient market in back-up supplies, flexibility and the relevant ancillary services. The market place will bring together intermittent generators with those able to offer storage, fast back-up and DSRs. This will be through the balancing and flexibility

of energy markets and through the RSO auctions. For some, like solar, the intermittency has considerable predictability. Wind intermittency does not follow the time of day. Nuclear offers considerable uncertainty about the project construction period and the timing of entering into the generation market. The various renewables and low-carbon technologies offer different intermittency challenges, and require different solutions to translate intermittency into EFP. The new technologies offer alternative and increasingly effective solutions to these problems.

21. The market in back-up already has lots of players. Technological progress is developing rapidly. There are major advances in batteries, and electric transport offers up lots of opportunities to manage storage in car batteries. Smart technologies are empowering the demand side of the market, and much better information from smart meters and from new apps and energy management services has become available.

22. This rapid technical progress keeps catching the government (and others) by surprise. In the first rounds of the capacity auctions, the winners – small diesel generators and OCGs – were not what was anticipated (CCGTs were assumed to be the likely winners). The prices also turned out to be much lower that BEIS expected.

23. The EFP auctions bring to an end the increasingly hopeless task of trying to second-guess how the new technologies will evolve, and what their costs will be. Rather, there will be competition through this secondary market to best meet the intermittency from the renewables (and nuclear delivery), as intermittent generators try to internalise these impacts.

24. As with all market design questions, there is a choice between leaving these markets to develop spontaneously, and actively setting up the rules in advance. In the secondary market, there is a strong case for allowing the markets to develop against the backdrop of the wholesale market and the balancing mechanisms. Provided the EFP contracts are enforceable, and there are strong penalties for non-delivery, and in the absence of FiTs and low-carbon CfDs, the intermittent generators have strong incentives to contract and trade in the markets for back-up and flexibility, and where appropriate to directly invest in reducing their intermittency. They will want to participate in these secondary markets to reduce their de-rating in the EFP auctions.

25. Penalties for non-performance can either be imposed centrally by the NSO and RSOs for the EFP auctions, or by having a short-term clearing market for distress and emergency back-up supplies. This builds on the cash-out rules Ofgem imposed. There is the legal liability: those that offer contracts for back-up could be pursued by the usual legal contract enforcement and damages route.

26. The key and overriding point here is that this is not a secondary market that the government tries to second-guess, and aside from rule-setting and usual market oversight activities, it should have little if anything to do with government and regulators. (I return to the NSO and RSO role below.)

27. The EFP auctions are for a given amount of capacity, and that capacity has to meet the two overriding objectives: it must be consistent with the carbon budgets, and the security of supply requirements.

28. Provided the government sets the carbon price at whatever level is necessary to achieve the carbon budgets, there is no problem in meeting the carbon budget caused by the EFP auctions.

29. On the cost-competitiveness question for current renewables (and nuclear), and even where there is a scored auction because the carbon price is not high enough, the EFP auctions will reveal if and to what extent there remains a competitive gap and how it differs between the alternative forms of generation. This in itself is extremely valuable market information. It reveals whether the lobbyists are right when they claim that renewables of specific types are, or are likely to be, able to operate without subsidies and be grid-competitive once the carbon price has been fully taken into account.

30. In the absence of a proper carbon price, and while a competitive gap remains, the single auction can take the emissions into account in selecting the winners. Bidders might, for example, be required to state their emissions as part of their bids, and to commit to these emission profiles over the life of the EFP auction. The capacity requirement can then be met by reading down the supply curve to get the least-cost result for the given carbon budget.

31. The second set of questions concerns how to determine the amount of capacity to auction, how frequently to auction, and what the term structure of auctioned contracts should be.

32. There are two ways of going about this: the NSO could decide from time to time as events unfold in a discretionary way; or there could be regular fixed auctions with quantities set in advance. An intermediary approach is to set out the principles and rules by which the fixed quantities will be decided and then to mechanically apply them.

33. The case for discretion is twofold. First, this is how a purchaser of services of this kind would operate in other markets, because the uncertainty is great and new information is valuable in recalibrating the requirements, in part because of the specific very rapid technological advances. Second, the

uncertainty about the scale of plant retirement and the new demands from the digital economy (notably EVs) is significant.

34. Discretion would be operated by the central buyer – this is the NSO and eventually the RSOs, to which I return below.

The pricing of networks

35. The EFP capacity auctions deal with the intermittency in delivering capacity. They do not address the costs to networks of intermittency and location. This requires nodal pricing, and here new smart technologies open up a much bigger prospect for considerable advances.

36. It is obvious that the system costs depend not only on the plant intermittency, but also on the location of the generating plant. Smaller-scale renewables tend to be in more remote locations, and these require transmission and distribution networks to cope with them. Similarly, nuclear power tends to be on the coast, and away from the populations that need the electricity.

37. In the past, the British electricity system has been centrally planned around a relatively small number of large power stations. In the 20th century, these were overwhelmingly coal (80%) and nuclear (20%). Because coal is both heavy and bulky to transport, the power stations tended to be near the coal fields, and the transmission system was developed to cope with the necessary power flows to the centres of demand.

38. Connecting, say, 30 large power stations is a relatively straightforward exercise, especially when the power stations and the grid were both centrally planned – and indeed when the nuclear and coal industries were all within the umbrella of common public ownership.

39. The new world of decentralised and small-scale generation presents a very different challenge. So far, the share of renewables and small-scale generation has been low enough to be absorbed within a system designed for large-scale power stations. But this will not be the case for long.

40. In a decentralised world, supply and demand can be met locally in a way it could not in the old world. Indeed with the coming of batteries and other forms of storage, and the smart technology to back it up, some have already started to consider the possibility of opting out of the networks altogether and becoming partially self-sufficient.

41. There are two responses to this. First, there needs to be a new focus on opening up the regulatory model, and I recommend the development of the RSO model (see below). Second, the new ability

to use smart meters, smart networks and, more generally, smart systems means that the pricing of networks, and especially nodes, can play a much bigger role.

42. One version of nodal pricing in networks is to consider the use of auctions, notably when enhancements to networks are proposed. Any investment in upgrading a network can be offset by investing in generation, storage and demand-side measures instead. The RSO can use auctions before new investments are made. This will reduce the costs for the system as a whole. There is a core role for both the NSO (for the national transmission system) and the RSOs (for regional networks) in this auctioning process.

The institutional structures: the role of the NSO and RSOs

43. In the above market design, and with fixed capacity contracts gradually taking over from energy contracts, a number of questions arise as to who is in charge (and whether anyone needs to be in charge). The capacity world is still one where there is a system role and hence some aspects of the central buyer model remain. Security of supply is, as noted above, a system property. The firm power world is one where the central buyer does the minimum necessary to make sure the security objective is met.

44. The central buyer is one part of the system operator function, and this role has been conflated with the conventional one of operating the system at each point in time. The central buyer is concerned with the system operator functions over time. These should be clearly split out. For the avoidance of confusion, when I refer to the system operators, I do not mean the day-to-day operations.

45. The greater role for the system operator was developed as a consequence of EMR. EMR left the prospects for further investments in gas exposed, with no obvious mechanism to ensure that sufficient new capacity would be built to handle the retirement of coal and the gradual closure of most of the nuclear power stations. The intermittent generation undermined the economics of CCGTs in particular.

46. National Grid as system operator was given these extra responsibilities, notably the organisation of capacity auctions. It also has a role in advising government on various dimensions of the electricity systems and the required capacity margins.

47. The adoption of EFP auctions as described above strengthens the case for a fully independent NSO.

48. Decentralisation means that a number of system security issues are devolved to the regional level. This suggests that each region should have its own system operator function. Whereas the NSO organises the firm power auctions for the system as a whole, the RSOs are responsible for the integrated development of the local networks and the local generation, distribution and supply, including the auctioning of network developments.

49. The RSOs can take on a number of functions that are currently in the DNO licences. RSOs should be given the duty to secure regional supplies, and with this the oversight of the necessary investment in distribution, currently regulated by Ofgem. These local system requirements would not be carried out by the RSOs, but rather contracted out. These contracts could be for specific enhancements and maintenance, or for the complete network service. The RSOs can invite a much wider range of options to secure regional supplies. This contracting would take the place of periodic reviews and price caps.

50. With the core responsibilities given to the RSOs, the distribution companies could in effect become contractors, and one among many competitive suppliers. There would remain the need to address time-inconsistency and ensure that the investments are properly remunerated. This would be through contracts with the RSOs, which would ensure that the monies can be recovered through allowed contract charges. The RSOs would have the contractual obligations to the investors, the revenues for which would be recovered via the RSO system charge to customers. This would in effect be a version of the duty to ensure that functions can be financed, by making sure that they are paid for. The RABs become contractualised in a more disaggregated way.

51. Several subsequent changes would follow which would further reduce the role of regulators and increase competition. In this RSO world, where the RSOs have the obligation to ensure that the functions are carried out, the distinction between distribution, supply and generation licences would be gradually dismantled. This, for example, would sort out the misallocation of the smart meter programme to supply and not distribution (as in almost all other EU member states). The allocation problem could be solved by abolishing the regulatory distinction. The meters themselves would be backed by RSO contracts, and hence effectively be put into the RSO guarantees, given similar RAB protection.

The role of Ofgem and government

52. In the NSO and RSOs model, much of the detailed periodic review regulation withers away. Instead of five- or eight-year price caps, the DNO revenues would be determined by the value in competitive contracts. This might be for all or part of their existing functions, and DNOs could bid for contracts against incumbent DNOs to the relevant RSO.

53. To the extent that a role for Ofgem in periodic reviews remains, this could be carried out by a general utility network regulator. There would be roles for industry competitive oversight, for representing customers, and for appeals mechanisms.

54. In this new model, the role of government is confined to the setting and revision of the major objectives – the climate change and security of supply objectives – and the provision of guidance to the NSO and RSOs. In the case of the climate change and carbon budgets, this has been delegated to the CCC, and hence government's role is limited to the analysis of the carbon budgets proposed by the CCC and the decisions about whether each is accepted or an alternative is brought to Parliament. Government would also be responsible for setting and revising the carbon price. Beyond this, it obviously has a role in international negotiations on climate change.

55. There would remain a major role for government in R&D and innovation. The private markets are widely understood to have weak incentives to conduct certain types of R&D, and there may too be a case for subsidising new technologies in their initial roll-outs. To date, this has been wrapped up in the separate FiTs and low-carbon CfDs for different technologies, on the premise that some are infant and immature technologies and need customers to pay higher prices to make the transition to markets.

56. The facts undermine this argument. The differentials in the FiT contracts do not closely reflect the degrees of immaturity, and none has a target date for maturity. Rather, the differential FiTs have ushered in considerable scope for lobbying, and this has been exploited by the various vested interests.

57. The design of R&D and innovation policy is beyond the scope of this review. However, it is worth noting a number of desirable features. These include: the need to avoid picking winners (or losers); the focus on generic technological advances; the role of independent scrutiny; the widespread risk of capture; and the fact that R&D is an international rather than a purely domestic activity. In deployment, if, for example, Germany decides to engage in a large-scale, first-generation solar roll-

out, and if China invests and subsidises large-scale solar panel manufacture and wind turbines, there is little added value in the UK replicating the same spending patterns. R&D needs to focus on those areas that others are not pursuing and for which there is a reasonable prospect of UK success. The current plurality of institutions and interventions in energy R&D might merit some amalgamation and consideration of a UK Energy Research Laboratory.

58. By separating out R&D and innovation from the FiTs and CfDs through the EFP auctions, the government would instead make its public expenditure decisions directly, and not via the differential inflating the prices for chosen technologies. It would then be open to the government to charge these extra subsidies to R&D directly to electricity consumers via the system charges or through general taxation. The R&D policy would form a key part of the *Industrial Strategy*.

59. The government has a central role in setting other targets and ensuring that the necessary infrastructures are in place. These include EVs, the regulation of vehicle emissions, and air quality targets. The decision to phase out petrol and diesel cars (except hybrids) by 2040 necessitates a new battery-charging infrastructure and working out who should pay for it.

60. Many new infrastructures are initially left to the market to develop, and then rationalised *ex post*. This was true of railways and electricity in their early days, and has been the case for broadband, mobile phones and the internet.

61. The difference in the transport case is that EV battery-charging impinges directly on an existing and regulated infrastructure. It is a role for government to decide what *ex ante* investments in what sort of charging systems might be required. This can be done in conjunction with the NSO and RSOs discussed above. But there is also clearly a role for the National Infrastructure Commission and its long-term statement of infrastructure needs.

62. The final set of decisions for government relates to the allocation of the system fixed costs. As noted in section 9, these costs cannot be switched from, other than by opting out of the system completely. How these are allocated is critical in terms of social objectives, fuel poverty and industrial policy and competitiveness. In the new capacity, firm power and fixed-cost world, it is for government to choose the principles of how these costs should be allocated. This is a long-term issue as more and more zero marginal cost generation comes onto the market, but already there are practical questions which it is the role of government to address. Some of these are immediate and are developed in the next section.

Summarising the new model

63. The merits of the new model are that it maximises the scope for auctions and competitive bidding; enables a fully private competitive market in back-up, storage and demand-side measures; and uses the market to identify the full and true costs of all the technologies, especially intermittent ones. It opens up the decentralised market opportunities, gets rid of the licence distinctions between supply, distribution and generation at the regional level, and moves on from the periodic review regulatory model for DNOs.

64. The new model is much simpler and it enables much of what Ofgem and BEIS currently do to be dismantled. It is the model which meets the principles: it is simple; it places responsibility for costs on those who cause them; and it maximises the use of auctions and competitive processes. Most importantly the new model goes with the flow of the big technological changes. It embeds storage, DSR and zero marginal costs, and maximises the chances that these great new opportunities will continue to drive down the cost of energy.

12. A Road Map: What to Do Now

1. The long-run destination is a competitive electricity market, with a uniform carbon price and auctions determining investments on an EFP basis; markets in storage; demand-side measures and back-up supplies; a withering wholesale market; an NSO and RSOs ensuring the security of supply and opening up the networks to competition; and a much-reduced role for regulators and the government.

2. This is a comprehensive package for the determination of the least-cost ways of achieving the climate change and security of supply objectives in the long run.

3. Most of the steps necessary to get from here to there can be put in place in the near term. Some of these measures will require legislation, notably changing the licences and creating the NSO and RSOs, and giving them statutory powers and duties. Government should start the preparatory processes now – and specifically prepare a white paper.

4. Many of the measures to get to the long-term framework do not require legislation, and where they do, they may not require a new Energy Act. Harmonising carbon prices is in large measure a matter for Budgets and the annual cycle of Finance Bills.

5. In addition to these road map measures to get from here to there, there are some immediate problems with the cost of energy identified above which need to be urgently addressed to provide some much-needed relief to households and industrial customers.

6. Unless these measures are introduced, the widespread suspicion of the conduct of companies will continue to undermine trust, and thereby further exacerbate the costs of decarbonisation and erode the public's willingness to pay for the necessary decarbonisation investments. The status quo is unstable, and on an increasingly inefficient pathway.

7. There are a set of immediate actions which can be taken by BEIS, the Treasury, the CCC and Ofgem. These include the following.

(i) The creation of a 'legacy bank' for the out-of-the-market contracts for renewables and for nuclear – to be separated out from the industry costs and explicitly billed (section 5).

(ii) Consideration of securitisation of the legacy bank contracts, to drive down the cost of capital (section 5).

(iii) Exemption of industry from the legacy costs (section 9).

(iv) Setting out the capacity auction volumes necessary to address the coal and nuclear closures and uncertainty about Hinkley timings for the period through to 2030, and urgently contracting for the necessary capacity to overcome the coal closures (section 7).

(v) Setting out a road map to move to EFP auctions (section 7).

(vi) Ofgem to consider options for addressing the outperformance of transmission and distribution within the current period (section 8).

(vii) Replacement of the price caps for networks with the NSO/RSO model by the end of the current periods in 2021/23 for transmission and distribution (section 8).

(viii) Full separation of the NSO (section 8).

(ix) The publication of a default tariff for household electricity bills, based on the underlying costs, with published margins (section 9).

(x) In response to the draft legislation, Ofgem should consider a maximum regulated margin for suppliers as part of the default tariff in the development of an SVT price cap (section 9).

(xi) Consideration of harmonising the various explicit and implicit carbon prices (section 10).

(xii) The CCC should calculate the marginal costs of carbon reductions in agriculture, identify a least-cost economy-wide decarbonisation strategy, and consider the implications for the electricity sector of a more efficient overall decarbonisation profile (section 2).

(xiii) A gradual reduction in the size, scale and scope of BEIS's interventions, modelling and other activities (section 4).

(xiv) A gradual reduction in Ofgem's activities as the NSO and RSOs are developed, and eventually considering the merger of Ofgem with other network regulators (section 11).

(i) The creation of a 'legacy bank' for the out-of-the-market contracts for renewables and for nuclear – to be separated out from the industry costs and explicitly billed (section 5)

8. The EU Renewables Directive has been a very costly way of making marginal reductions in carbon emissions, and a poorly targeted mechanism to increase R&D and innovation. After 2020, if not before, the UK will no longer be subject to the target.

9. The UK cannot, however, escape the costs that it has contracted for renewables and nuclear. These are legacy costs.

10. Legacy costs overhang the market and distort final electricity costs and prices to households and businesses. They are analogous to legacy out-of-the-market banking contracts following the financial crisis in 2007/08.

11. The government should transfer the out-of-the-market elements of the ROCs, FiTs and low-carbon CfDs into a new legacy bank.

12. The exact legacy costs are a matter of considerable dispute, and their calculation depends on assumptions about future wholesale costs, the price of carbon, and the costs of intermittency. For simplicity, looking backwards, the LCF costs are a practical measure. Looking ahead, future out-of-the-market costs will depend in part on whether a carbon price is established at the level necessary to meet the carbon budgets and the CCA target.

13. The fact that the exact numbers are open to debate should not hold up the separation. The key point is the importance of the clear separation and a set of principles to deal with any further out-of-the-market contracts. Certainty about what is included, and therefore what can be securitised, is what matters, not getting the definition precisely right.

(ii) Consideration of securitisation of the legacy bank contracts, to drive down the cost of capital (section 5)

14. Consideration should then be given to whether the private or public sectors are best able to securitise at the lowest cost of capital. Current securitisations of completed projects in renewables attract returns typically of 6–10%, as against a government cost of capital of below 2%. Given that the contracts are guaranteed by the government, there is potentially a very large saving to be had here, which could significantly reduce the burden on households and businesses.

(iii) Exemption of industry from the legacy costs (section 9)

15. Industry is already largely exempt from most of the legacy costs. There is a good case for making industry completely exempt from what is in effect a recovery of sunk and past contract costs.

(iv) Setting out the capacity auction volumes necessary to address the coal and nuclear closures and uncertainty about Hinkley timings for the period through to 2030, and urgently contracting for the necessary capacity to overcome the coal closures (section 7)

16. The UK faces a cliff edge in capacity in the period through to 2025 as the coal power stations close, followed by the retirement of most of the existing nuclear capacity. There are very real risks to security of supply, and a risk to the climate change agenda if, as a result, emergency measures are required to keep the coal stations available.

17. The government should set out what measures the system operator should take to mitigate the risks associated with the uncertainty of Hinkley starting to generate.

(v) Setting out a road map to move to EFP auctions (section 7)

18. The temporary solutions to the capacity shortfalls should be accompanied by a clear plan to move to EFP auctions from 2020, covering the period beyond 2025. This needs to be done now, so that the EFP auctions can be set up, and run virtually in advance, and so that there is time for the development of the secondary markets in storage, the demand side, and back-up generation.

(vi) Ofgem to consider options for addressing the outperformance of transmission and distribution within the current period (section 8)

19. The costs of transmission and distribution have fallen substantially compared with the assumptions made by Ofgem at the last periodic reviews. In a five-year periodic cycle there is scope for relatively rapid corrections, and the transmission and distribution companies would already be having their prices reset. Households and businesses would be getting immediate relief now. The eight-year period under RIIO is too long, and the divergence from expectations too great.

20. In advance of the development of the RSO model set out in section 8, Ofgem should consider the options, including: doing nothing; an agreement with the utilities to a voluntary approach; or a formal review process.

(vii) Replacement of the price caps for networks with the NSO/RSO model by the end of the current periods in 2021/23 for transmission and distribution (section 8)

21. BEIS and Ofgem should set out a preferred model for RSOs now, ahead of the scheduled periodic reviews in 2021/23, and should consider abandoning the periodic review due at these dates, to be replaced by a formal auctioned contracts regime, with the transfer of some licence obligations from the DNOs to the new RSOs.

22. There will almost certainly need to be a transition period both while the RSOs are being set up, and for an initial period thereafter, in which the DNOs will continue roughly as at present, with a gradual opening-up of auctioning. After the end of the current periods, the regulatory contract between the DNOs and the RSOs should not be a fixed-priced one, but should focus on the particular elements that make up the costs, notably the cost of capital, the CAPEX and OPEX. Ofgem should develop a transition process.

23. From the end of the current periods there should be no more fixed-price periodic caps. Any interim measures should be explicitly temporary.

(viii) Full separation of the NSO (section 8)

24. The current arrangements for an internal separation of the system operator within National Grid are unsatisfactory. The introduction of EFP auctions will make them unacceptable. National Grid has considerable opportunities to enter the markets for storage, demand-side measures, and even back-up generation. In some cases it already has. As a major centre of expertise and with a major role in the carbon transition and the development of decentralised generation and smart systems, National Grid should be freed from the potential or actual conflicts of interests that the ownership of the system operator may give rise to.

25. The NSO should be given explicit duties to ensure the security of supplies, both in generation through the capacity auctions and with regard to the transmission networks. These duties should,

where they apply and are relevant, be transferred out of National Grid. There will be an inevitable element of discretion in the public interest, which should not lie with a private company.

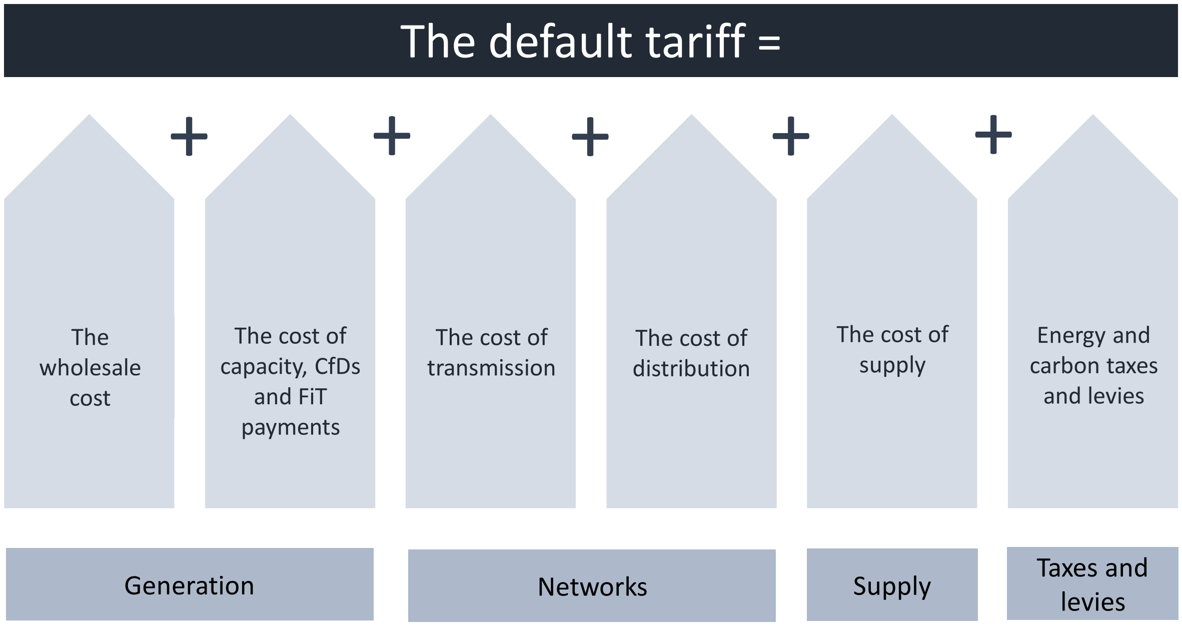
(ix) The publication of a default tariff for household electricity bills, based on the underlying costs, with published margins (section 9)

26. Households on the SVT have received a particularly bad deal as identified by the CMA, and competition has worked to the benefit of switchers often at the expense of non-switchers. Whereas in complicated and product-differentiated industries some of these practices might have a dynamic justification, they cannot and do not in electricity. It is unsurprising that there is a wide consensus that 'something needs to be done'.

27. These market power abuses are larger than reported for the full industry supply chain, since significant elements are outside the control of the suppliers, and are all the more surprising since the cost of electricity comprises clear and identifiable elements. These should be set out clearly and transparently for customers. Suppliers should not earn a significant margin on the large element of cost pass-through items.

28. There always is a default tariff, and the proforma structure of the tariff should be set out and all major suppliers should be required to offer it. The supply margin should be calculated on a common basis and published on the Ofgem website. Ofgem should produce a league table of margins so customers can instantly identify the cheapest supplier for the default tariff.

29. The suppliers would remain free to offer any other tariff they wished. Competition and especially competitive entry will be greatly enhanced by this default tariff. The main elements are as follows.



(x) In response to the draft legislation, Ofgem should consider a maximum regulated margin for suppliers as part of the default tariff in the development of an SVT price cap (section 9)

30. The focus of the debates about the design of price caps should be on the supply margin. In a period of rapid digitalisation, smart meters, and the intensification of competition in the offering of services around broadband hubs, any price cap on margins should be a maximum cap. The other elements in the default tariff ensure that only the exogenous costs – and nothing more – are passed through, and in the case of the wholesale costs this is the actual wholesale prices, with an error-correction mechanism. Past supply margins from the period when supply price caps were imposed are relevant to this consideration.

31. The default tariff is compatible with the government's draft legislation and the wider price cap it entails. All price caps are derived from the underlying costs, and the additional step to meet the government's objective is to cap the maximum allowed margin as part of the price cap calculation by Ofgem.

(xi) Consideration of harmonising the various explicit and implicit carbon prices (section 10)

32. The proliferation of explicit and implicit carbon prices is a cause of significant distortions, and these are likely to get worse as decarbonisation accelerates. The cost of energy is as a result higher than it needs to be to achieve the carbon budgets and the carbon target.

33. The carbon price should, where possible, be common across all activities in the economy. The Treasury should urgently conduct a review of the various numbers and measures of carbon to which the prices are applied.

34. Carbon pricing in transport should be reviewed as EVs grow in market share.

35. In reviewing these current various explicit and implicit carbon prices, consideration should be given to a long-term framework.

(xii) The CCC should calculate the marginal costs of carbon reductions in agriculture, identify a least-cost economy-wide decarbonisation strategy, and consider the implications for the electricity sector of a more efficient overall decarbonisation profile (section 2)

36. Carbon emissions are not confined to the electricity sector of the economy. Indeed, electricity contributes only 24% of the total. The CCC rightly argues that decarbonisation of electricity is critical to many of the other sectors, and hence has a special and leading role in decarbonisation.

37. Nevertheless, the importance of electricity should not detract from the fact that reductions in other sectors, such as agriculture, may be low-cost, and very much lower than the price of carbon implied by some or even all of the FiTs and low-carbon CfDs.

38. Agriculture is heavily subsidised already and has, net of these subsidies, a very small share in the UK economy. Many decarbonisation measures are ‘no regret’ even if the subsidies are left out, including the protection and enhancement of the soils, the protection of woodlands, and the general enhancement of natural capital.

39. The 25 Year Environment Plan and post-Brexit agricultural policies should consider the lower-cost opportunities for reducing carbon emissions and sequestrating more carbon in soil, woodlands and the like. The CCC should incorporate these considerations into its recommendations for the share and profile of the decarbonisation of electricity.

(xiii) A gradual reduction in the size, scale and scope of BEIS's interventions, modelling and other activities (section 4)

40. As the long-term energy policy framework takes shape, BEIS can gradually retreat and close down many of the activities it has taken on, on the back of the plethora of policy interventions.

41. BEIS should publish a consolidated list of all its current interventions in the energy sector, and set annual targets for the gradual removal of many of these, as auctions and markets take back the determination of prices, costs, outputs and investments.

42. As BEIS gradually reduces its activities and interventions, key tasks will remain. These are primarily in respect of the resetting of objectives – for climate change and security of supply. The government should give guidance to the NSO and RSOs on the capacity margins, and assist the Treasury in setting the carbon price. There should be an annual statement to Parliament summarising this guidance, building on the existing reporting lines.

43. BEIS should then be able to concentrate on its core *Industrial Strategy*, including the R&D and innovation policies which are important to the energy sector and the rest of the economy.

(xiv) A gradual reduction in Ofgem's activities as the NSO and RSOs are developed, and eventually considering the merger of Ofgem with other network regulators (section 11)

44. Ofgem was formed through the merger of two very small regulatory offices – OFGAS and OFFER. Initially OFGAS had around 20 people. Ofgem now has over 900 people (around one-third of whom administer various government schemes) and an annual budget of nearly £90 million.

45. Over the years, Ofgem has added more and more functions and become increasingly involved in the detailed regulation of both the markets and the networks. This is in line with the growth of regulation in water, transport and communications.

46. This growth will continue, unless checked by a move back to markets and auctions. The creation of the RSOs in particular provides an opportunity to gradually roll back Ofgem. The full introduction of EFP auctions and the transfer of certain licence functions and duties from the DNOs and National Grid to the NSO and RSOs will eventually facilitate Ofgem being merged into a single network regulator across all the utilities. The objective should be to return Ofgem to its former littleness, and as a result significantly reduce the regulatory burden and its costs.

13. Conclusions and Summary of Recommendations

1. The current level of detailed, multiple, overlapping and costly interventions is the unintended consequence of a host of *ad hoc* policy interventions including, but not limited to, EMR and the way it was implemented, as well as the addition of new objectives, and the general growth of regulation. These interventions keep on growing, as one measure is layered onto another, increasing costs and inefficiencies. The interventions have been wide open to pervasive lobbying and capture, and the result has been significantly higher costs. The current framework is not fit for purpose.

2. It is not stable: left alone it will get worse. Continuing down the current path will most likely result in ever-greater complexity and growing costs, independent of the changing technologies and cost structures identified in this review. At some stage the results will be sufficiently bad to motivate reform, but the longer this is left the greater the impact on the cost of energy, and the more the decarbonisation process will be inhibited.

3. The costs of energy are too high, and they should be going down. The opportunities ahead are exciting, and households and businesses should reap the benefits of the new technologies and the potential they bring. More investment should mean more profitable opportunities for energy businesses. Rapid falls in the costs of both renewables and intermittency as the demand side and storage play ever greater roles open up the prospect of a subsidy-free energy market – provided everyone pays the full cost of carbon required to meet the carbon budgets and the CCA target.

4. What is required, and what is set out in this review, is a radical simplification of energy policy, getting government back out of the detailed interventions it has become entrenched in. Government should do what it is best at and what it is necessary for it to do. It should set the objectives, and give guidance on the capacity margins. It should set the carbon price and the various taxes. It should stop picking winners and engaging in detailed investment decisions.

5. Markets work best within clear structures. They are the primary means to an end – ie, of providing the least-cost clean energy. The system questions will not be answered adequately by purely private markets. For this there needs to be a new architecture. The system operators are the right candidates for taking care of system requirements. As the new technologies usher in the prospect of decentralised generation, networks and supplies, and as new energy services models emerge, the RSOs are the best way to maximise the scope for these technologies, and especially to

incorporate EVs. Competitive auctions have already made a big difference to costs. They can achieve much more in the decentralised framework set out in this review.

6. The measures here comprise a package. While some – like the default tariff and the legacy bank – are worth doing anyway, the main ones fit together. Ending the FiTs and low-carbon CfDs makes sense only if there is something better to put in their place, and this includes the carbon price and the EFP auctions. The decentralisation opportunities work best in the context of RSOs and the ending of the licence boundaries.

7. Some of the measures recommended here will inevitably need legislation. When there are changes in technology on the scale described in this review, they render the cost structure, the industrial structure, the policies, the regulation and the institutions increasingly out of line with the underlying economics. The choice is stark: carry on with the current energy policy framework and there will be increasing barriers to the penetration of the new technologies, and the incumbents will be able to thwart entry; or embrace a new long-term framework.

8. Incumbents often argue against change because they claim it creates uncertainty. In any regime with multiple subsidies and other interventions there are powerful vested interests in the status quo. My recommendations challenge the transmission and distribution companies, the suppliers, and the owners of conventional generation. Periods of radical technical change are not usually good news for incumbents and my proposals are designed to speed the path to the new technologies. In any event the old certainties of the 20th-century model are a thing of the past. The coming of EVs, new renewables technologies, smart systems and new energy services are inherently uncertain. They are bound to be.

9. Some the changes I recommend are urgent. But the long-term framework needs careful consideration. This review is not a detailed blueprint. I recommend a framework. The task now is to fill in the details in a measured way.

Summary of main findings by section

PART I: The Building Blocks

SECTION 2: THE OBJECTIVES

- The CCC should give greater weight to the prospect of rapid technical progress in future carbon budgets and take into account the possibility of falling gas prices.
- The CCC should consider in more detail greater contributions from agriculture, and these should be integrated into the 25 Year Environment Plan.
- The government should consider how to develop and enhance integrated pollution control to bring greater consistency between the CCA targets and the other policy objectives.
- The government should set out in a formal annual statement its position on the security of supply margin, and this statement should constitute formal guidance to the system operators.

SECTION 3: CONSTRAINTS: HOUSEHOLD AND INDUSTRY BILLS, THE USO AND THE ABILITY TO PAY

- The government should create and monitor a more sophisticated set of price and cost comparators beyond the Eurostat approach.
- The broadband USO requirements should be assessed alongside the smart meter roll-out. BEIS and the Department for Digital, Culture, Media & Sport should coordinate the timings and scales of these investments.
- The government should consider the allocation of the system costs and, in particular, the option of providing for a basic block of electricity capacity at a lower fixed cost to address fuel poverty.

SECTION 4: CURRENT POLICY INTERVENTIONS AND FORECASTING

- The detailed mass of interventions is beyond the capacity of officials, regulators and companies to comprehend.
- Complexity encourages lobbying by vested interests in each intervention.
- Piecemeal reforms will almost certainly fail.
- BEIS should consider qualitative analysis of the long-run future of fossil fuels and fossil fuel demands as demand falls with decarbonisation.
- BEIS (and CCC), to the extent that it continues to use assumptions for the residual non-auctioned contracts, should consider a much wider range of scenarios, including a low and falling one for oil, gas and coal prices.

- The government should carry out a comprehensive review of statistical, scenario and forecasting activities in BEIS.

SECTION 5: THE LEGACY COSTS

- The government should adopt a low-carbon definition to replace the narrow EU renewables definition as a temporary measure for the renewables transition towards subsidy-free status.
- Legacy contracts should be grouped into a legacy bank. The bank should include all the outstanding ROCs, FiTs and low-carbon CfD contracts. These should be ring-fenced and separated, distinguishing between the competitive price of electricity going forward and what is in effect a tax on customers.
- Government should consider how it wants to allocate legacy costs between customers. This should be explicit and transparent in customer bills.
- It is likely that further nuclear projects will add to the legacy bank liabilities, as will Hinkley beyond 2030.

SECTION 6: TECHNICAL CHANGE

- Technology developments are changing the fundamental cost structure of the industry. An active demand side, storage and increasing zero marginal cost generation represent each and jointly a radical structural break with the past.
- The *Industrial Strategy* should set out a regulatory framework for EV charging.
- Government should conduct a fundamental review of the complex energy research funding and its institutional organisation.
- Government should consider amalgamations and mergers and the possibility of a new UK Energy Research Laboratory.
- Innovation policy should focus on designing a general capital grants and supportive tax regime rather than try to pick winners.

PART II: The Electricity Cost Chain

SECTION 7: ELECTRICITY GENERATION

On the wholesale markets

- NETA was a mistake, and in particular the loss of the compulsion to sell power through the wholesale market and the abolition of a capacity mechanism.
- Market power is nevertheless limited by the combination of the capacity market and the excess capacity margin it creates, and zero marginal cost renewables and nuclear.
- The wholesale market is already becoming less economically significant as a way of recovering the full costs of electricity generation.

On the capacity market

- The capacity market is the prime vehicle for ensuring security of supply.
- The initial capacity auctions have been broadly successful.
- The system operator should be separated from National Grid as a public interest body, the NSO.
- The NSO should have the duty to ensure adequate capacity and discretion in its delivery.
- The government should set the desired capacity margin, taking account of all the new DSR and storage options, through an annual statement to Parliament.
- The government should give guidance to the NSO on how to handle the uncertainty around the 13GW potential nuclear investment in the capacity auctions.

On the FiTs, low-carbon CfDs, and the unified EFP auction

- The FiTs and low-carbon CfDs and the capacity markets should be merged into a unified equivalent firm power market.
- EFP contracts should be auctioned by the NSO on an ongoing basis, with the NSO responsible for determining the timing, length of contracts, and amounts of capacity auctioned, subject to government guidance on the overall capacity margins for security of supply purposes.
- The EFP auctions should be primarily based on price, but the allocation of contracts should take account of the carbon impacts in the absence of a proper carbon price necessary to meet the CCA and carbon budget targets.
- The government to issue guidelines for the criteria for scoring bids.
- The NSO should examine the bids, and then take account of the carbon budget constraints, and make awards of contracts which are least-cost, subject to the carbon constraints.
- In the absence of a proper carbon price, where the gaps between fossil fuel and low-carbon bids are large, the NSO should consult with the CCC to identify whether there are greater value-

for-money savings in carbon which could be made in other sectors, notably transport, buildings and agriculture.

- Over time, the RSOs proposed in sections 8 and 11 should take on some of these auctioning functions in conjunction with the NSO.
- The market in the back-up for intermittency to assist the renewables should be further encouraged, so that the intermittency can be met through a portfolio of contracts. This market should further bring into play demand responses, storage and back-up generation. These suppliers of services will then be able to match up with the expected intermittency of the renewables generators. The renewables can then bid for less de-rated EFP contracts.
- Renewables will remain able to sell non-firm power, and to enter into long-term contracts with purchasers of non-firm power – for example, companies involved in vehicle-charging and energy services businesses.
- As with all such contractual arrangements, provision will need to be made for default and other failures, and these responsibilities should lie with the NSO and RSOs, as recommended in section 11.
- If the above first-best approach is rejected, and after all current commitments have been met in full, the FiTs and low-carbon CfDs should be restructured according to their three phases, with capital support and tax concessions in respect of the project development and construction phases, and then at completion a refinancing arrangement put in place. Long-term, fixed-priced energy contracts for the whole project life, or a substantial period of its life, should eventually be abolished.
- A closure date for the FiTs and low-carbon CfDs should be set.

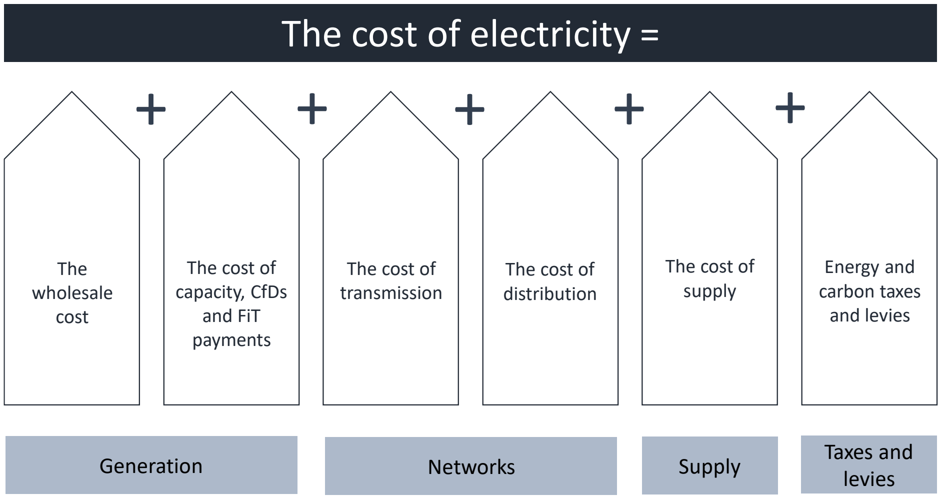
SECTION 8: NETWORKS

- Ofgem should carry out an assessment of the three options to tackle the scale of outperformance in the current periods – do nothing; arm-twisting; and a one-off resetting.
- The existing regulatory periods should be the last, and the conventional RIIO framework should be replaced when the periods come to an end, or after a shorter roll-over period, by a streamlined and much simpler model, bringing greater scope for competition and for markets to bear down on costs.

- The NSO should take on some of the duties in respect of the functions in the licences for transmission and including the duty to ensure the security of supply. A similar set of duties should be placed on the RSOs.
- The licence distinctions between distribution, generation and supply should be abandoned at the regional level, to be replaced by a single, simpler licence.
- The RSOs should determine the system requirements to ensure security of supply consistent with the carbon budgets and targets, and auction contracts for the delivery of required investments and services. These might be bundled together as in the existing DNOs, or disaggregated.
- The DNOs and suppliers can share smart meters, thereby significantly reducing their costs of capital. A regional RAB would remain, guaranteed by the RSO, and this could be securitised at a low cost of capital.
- DNOs would be free to engage in generation and supply, and hence incentivise choices between investment in new-generation capacity, including renewables, and networks.
- The role of Ofgem would be substantially diminished: there would be no further periodic reviews, and the NSO and RSOs would take on a number of regulatory functions currently performed by Ofgem.
- The NSO and the RSOs should jointly form an overarching council so that their respective activities can be coordinated.
- There would be residual regulatory roles to fulfil, and these could be absorbed into a single network regulator alongside those of water, transport and communications.

SECTION 9: ELECTRICITY SUPPLY

- There should be a default tariff as follows.



- The legacy costs should be clearly and separately identified on bills (see section 5).
- The supply margin should be published, so that customers and entrants can easily see the costs of supply that the supplier controls.
- In implementing new legalisation for a more comprehensive price cap to protect SVT customers, Ofgem should focus on setting a maximum supply margin, leaving the companies and entrants free to offer customers lower margins and any other tariffs they choose. The rest of the price cap can incorporate the other elements of the default tariff.
- To reduce the risks to suppliers, there should be explicit error-correction mechanisms in the default tariff.

SECTION 10: ENERGY TAXES, CARBON PRICES, LEVIES, AND REGULATIONS

- The Treasury and BEIS should conduct a detailed review of all the different explicit and implicit carbon prices with a view to identifying major simplifications and harmonisations.
- The Treasury should analyse two possible generalised carbon prices – a generalisation of the fuel duty to all three fossil fuels; and a generalisation of the CPF to the whole economy.
- The government should consider whether a mandatory coal closure programme would be more cost-effective than the various schemes, costs and regulations currently affecting the coal power stations.
- Industry should pay the harmonised carbon price.

- There should be a border carbon price in the context of the CCA unilateral carbon production target.
- The Treasury should consider the general future of the CCL in a long-term framework in the context of a border carbon price.
- Industry should be exempt from the legacy costs.
- Consideration should be given to socialising the legacy costs.
- Energy efficiency should be addressed primarily through standards and other non-tax and non-levy measures.
- The ECO confuses fuel poverty and other welfare and distributional issues with market failures in the take-up of energy efficiency opportunities. It should be explicit in household bills.