Central Planning with Market Features

How renewable subsidies destroyed the UK electricity market

RUPERT DARWALL

WITH A FOREWORD BY SIR IAN BYATT

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GLOSSARY OF TERMS

CBI Confederation of British Industry

CCGT Combined Cycle Gas Turbine

CEGB Central Electricity Generating Board

CEPA Cambridge Economic Policy Associates

CfD Contract for Difference

DECC Dept. of Energy and Climate Change

DTI Dept. of Trade and Industry

DSR Demand-Side Response

ECO Energy Companies Obligation

EMR Energy Market Reform

ETS EU Emissions Trading Scheme

HVDC High Voltage Direct Current

kW Kilawatt

kW Kilawatt Hour

MW Megawatt

MWh Megawatt Hour

NAO National Audit Office

NEA Nuclear Energy Agency

OECD Organisation for Economic Co-operation & Development

Ofgas Office of Gas Supply

Ofgem Office of Gas and Electricity Markets

Ofwat Water Services Regulation Authority

PFI Private Finance Initiative

TWh Terawatt Hour

SUMMARY

The story so far

Energy policy represents the biggest expansion of state power since the nationalisations of the 1940s and 1950s. It is on course to be the most expensive domestic policy disaster in modern British history. By committing the nation to high-cost, unreliable renewable energy, its consequences will be felt for decades.

Yet it wasn't so long ago that Britain led the world with electricity privatisation and liberalisation – the last big policy achievement of the Thatcher years – cutting bills and driving huge gains in capital and labour productivity, gains which are now being reversed.

- What went wrong?
- What are the costs?
- What can be done?

The re-imposition of state control is not because privatisation failed. As the Government concedes, 'historically, our electricity market has delivered secure supplies, largely due to competitive

markets underpinned by robust regulation.'[1] Instead, state control is the result of imposing an arbitrary form of decarbonisation involving an extremely costly European target for renewables generation (principally wind and solar energy) which Tony Blair negotiated at his farewell European Council in 2007. The result is that the privatised electricity sector is being transformed into a vast, ramshackle Public Private Partnership, an outcome that promises the worst of all worlds – state control of investment funded by high-cost private sector finance, with energy companies being set up as the fall guys to take the rap for higher electricity bills.

The Government justifies the return of state control on the presumption that the price of fossil fuels will rise continuously, a view now rapidly overtaken by falling coal prices and the halving of oil prices in the space of five months.

What went wrong: Key errors in the decision-making process

Initial conditions. The key decisions and overall design of electricity privatisation withstood the test of time. Its one major flaw was creating a generating duopoly to enable nuclear power assets and liabilities to be transferred to the private sector. In the event, these liabilities were too large and uncertain. But it took more than a decade for the regulator and the market to break the duopolists' pricing power. This delayed the benefits of privatisation reaching consumers' pockets.

1 DECC (2012), *Electricity Market Reform: Policy Overview*, Annex C, p.8.

Policy Lesson #1

> There is a big political premium in getting the initial conditions right. Although privatisation worked, uncompetitive initial conditions helped create the impression that the benefits went overwhelmingly to shareholders. Securing competitive conditions at the outset improves the post-privatisation politics, reducing the political incentives to intervene.

Shift to corporatism. With the exception of the Windfall Tax, which had been fuelled by this perception, New Labour retained the basic architecture of privatisation. However, there was a philosophical shift to using regulation to deliver wider public policy objectives. This turned the market from being an arena of competing firms to viewing them as the public sector's corporate partners.

Policy Lesson #2

> Using economic regulation as a tool of government policy is incompatible with having a competitive market. Instead, economic regulation should be tightly focused on expanding competition and providing a substitute for competitive pressure via periodic price cap reviews.
>
> A better approach is to treat electricity as if the sector were entirely competitive and use standard policy instruments such as taxation, welfare, public spending and traditional forms of regulatory interventions and not using the utility regulator's tool box.

Energy security. Other than the Windfall Tax, New Labour's first intervention was occasioned by the 1997/98 'coal crisis', when the expiry of coal contracts threatened the closure of a small number of pits. 'Energy security' was invoked to justify slowing down the 'dash to gas'. Energy security is a powerful excuse to justify market-distorting policy interventions, although the miners' strike in 1984-85 showed the efficacy and low cost of stockpiling and using moth-balled generating capacity.

Policy Lesson #3

> There needs to be a compelling justification to override the economics of free trade. Historically, appeals to energy security have resulted in the very energy attaining shortages such security was meant to avoid. In the case of Energy Market Reform and its precursor policy, the absence of stockpiling as a means of boosting energy security is evidence that energy security is used as a cover for other objectives.

Foundational Error. The turning point which led to the demise of the market was not proceeded by extensive policy appraisals or analysis of alternatives to the market, but from the adoption of the renewables target at a European Council meeting. Target-driven policy objectives are inflexible. They prevent exploration of trade-offs. The more compressed the deadline, the higher the costs. The overriding focus on meeting the target narrows the field of vision, so that emerging difficulties from other countries, notably Spain and Germany, were ignored as evidence for reappraising the target.

Policy Lesson #4

> Setting a target before analysing the costs, operational implications and likely unintended consequences, without considering alternatives constitutes the foundational error in the entire process from which, in one way or another, subsequent errors flowed.

Target-driven policy-making. Cost, efficiency and affordability were subordinated to the goal of meeting an arbitrary target. Instead of seeing the market as a price discovery mechanism to reveal the lowest-cost producer, policy sought to disguise (socialise) the true costs and implications of renewables to minimise the apparent cost of the policy.

Policy Lesson #5

A policy framework to encourage renewables that systematically conceals their true costs will result in higher costs and higher electricity bills for the same quantum of renewable capacity.

Form over function. Having decided to adopt a renewables target, there has been no comprehensive analysis of its costs, benefits and implications for the market. In particular, decision-makers did not ask what exactly electricity consumers get in return for the use of high cost private sector capital and whether it represented value for money for them.

Policy Lesson #6

Before adopting EMR, policymakers should have evaluated it against a public sector comparator so that the net cost/benefit of using private sector capital is identified and quantified, rather than being implicitly assumed.

What are the costs: Renewables' hidden costs

The costs of intermittent renewables are massively understated. In addition to their higher plant-level costs, renewables require massive amounts of extra generating capacity to provide cover for intermittent generation when the wind doesn't blow and the sun doesn't shine. Massively subsidised wind and solar capacity floods the market with near random amounts of zero marginal cost electricity. It is therefore impossible to integrate large amounts of intermittent renewables into a private sector system and still expect it to function as such.

To keep the lights on, everything ends up requiring subsidies, turning what was once a profitable sector into the energy equivalent of the Common Agricultural Policy. Worse still in a highly capital intensive sector, because prices and therefore revenues are dependent on government interventions, private investors end up having to price and manage political risk, imparting a further upwards twist to costs and prices.

Without renewables, the UK market would require 22GW of new capacity to replace old coal and nuclear. With renewables, 50GW is required, i.e. 28GW more to deal with the intermittency problem. Then there are extra grid costs to connect both remote onshore wind farms (£8 billion) and even more costly offshore capacity (£15 billion) – a near trebling of grid costs.

Including capacity to cover for intermittency and extra grid infrastructure, the annualised capital cost of renewables is approximately £9 billion. Against this needs to be set the saved fuel costs of generating electricity from conventional power stations. For gas, this would be around £3 billion a year at current wholesale prices, implying an annual net cost of renewables of around £6 billion a year. The cost of renewables is even higher compared to coal (which is being progressively outlawed).

What can be done: The worst of both worlds

Intermittent renewables destroy markets. You can have renewables. Or you can have the market. You cannot have both. The hybrid of state control and private ownership is far from optimal and inherently unstable. At no stage has there been any published analysis demonstrating that the use of private capital delivers better value for money than a public sector comparator.

There are two options to align ownership and control:

- If renewables are a must-have – although no government has made a reasoned policy case for them – then nationalisation is the answer; or

- the state cedes control, ditches the renewables target and returns the sector to the market.

Nationalisation removes political risk thereby cutting the sector's cost of capital. Together with the savings from abolishing retail competition, it would cut average bills by around £72 a year now, and £92 from 2020. By contrast, ditching the renewables target and returning the sector to the market would save households around £214 a year, assuming gas replaces renewable power. The saving would be greater using coal, which is now around 45 per cent cheaper than gas. This option would depend on securing a permanent opt-out from the EU renewables directive and any successor policy imposing targets on individual member states.

The speed with which these savings could be realised depends on how quickly the extra costs of renewables can be flushed through the system. This would involve using all legal means to cut renewable subsidies, allocate extra grid costs related to the renewable projects that gave rise to them and internalising extra capacity costs with a compulsory wholesale Pool.

FOREWORD

Rupert Darwall's timely paper shows the financial and institutional cost of pursuing a dash for decarbonisation at the expense of a well-regulated electricity market.

A rapid switch to high-cost renewable energy may be in compliance with the Climate Change Act, although unilateral action by the UK will have a negligible effect on global warming. And the reversal of the progress made since privatisation of the electricity industry, under the pretence of improving the functioning of markets, is a major step backwards into a world of command and control, where business decisions are taken by politicians.

Right across the infrastructure sector, concentration on methods of financing projects is leading to inadequate or bad analysis, where superficially attractive projects are no longer subject to proper cost/benefit tests, nor designed in the most cost effective way. Investment in infrastructure is essential, but individual projects need to be carefully appraised and not regarded as intrinsically desirable. Results matter; not all investment produces adequate returns.

Ministers have discovered a credit card which enables them to spend the people's money without the disciplining effect of raising additional taxes. This card was first used by Chris Patten in the early 1990s when he realised that water privatisation enabled him to finance environmental projects by placing obligations on water companies without going to the Treasury, leaving the regulator the duty to ensure that the additional expenditure could be financed by raising prices to customers.[2]

Ofwat responded by starting a "cost of quality" debate[3] and achieved regular discussions with Ministers, including the Treasury and No. 10, about what obligations were essential and affordable. Time has shown how necessary it is to continue this debate in public, in particular to analyse the cost of quality **before** Ministers take decisions.[4]

Initially Ministers specified objectives, many of them derived from EU Directives, but left companies to choose solutions, subject to meeting the regulator's price limits. But in the case of stormwater drainage in London, Ministers are now specifying a solution in the form of a £4 billion tunnel, although the objectives could be met much more modestly.[5] There are other infrastructure solutions looking for problems. In the case of HS2, we see the objectives

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2 Byatt, I. (2012) *Water: Supply, Prices, Scarcity and Regulation,* IEA Current Controversies Paper No. 37.

3 Ofwat (1992) *The Cost of Quality: A Strategic assessment of the prospects for future water bills*; Ofwat (1993) *Paying for Quality: the Political Perspective.*

4 Walker, A. (2009) *The Independent Review of Charging for Water & Sewerage Services,* See esp. Chapter 5 of Final Report.

5 Binnie, C. (2014) *Thames Tideway Tunnel Costs and benefits analysis*; Binnie, C. (2014) *Thames Tideway: Measures to protect the river environment from the adverse effects of waste water discharges.*

shifting to justify a pipe-dream. In energy, there is the cost, not only of nuclear and wind generation, but the cost, not properly attributed, of additional investment in the transmission grid and extra generating capacity to deal with intermittent wind.

All of these projects will be financed by some combination of customers and taxpayers. Financing them through the private sector is typically more expensive, justified only where incentives to efficiency outweigh the higher cost of capital. When Ministers specify inputs, such incentives rarely exist. And private funds, especially private equity, are seeking quick returns and guarantees to cover exceptional risks.

The National Audit Office and the Public Accounts Committee are now taking an interest in these matters and have been looking at the impact of growth projects on customers' bills in individual cases and across the board. I hope they intensify their investigation of projects in their early stages, **before** large sums are committed.[6]

Darwall shows that, in the case of electricity, the failure to conduct objective cost/benefit analyses by assuming ever-increasing fossil fuel prices has been compounded by destruction of the incentives created by the privatisation of the electricity industry. Competition in generation had shown large benefits in the form of cost reduction. Through the abolition of the Pool and the failure to prevent oligopolistic practices, this has now been replaced by a flawed attempt to increase competition in the household retail sector.

Ministers have destroyed the emerging electricity market while talking of how it could improve competitive processes. They and

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6 Report by the Comptroller and Auditor General HM Treasury, Department for Environment, Food and Rural Affairs (2014), *The Water Services Regulation Authority Thames Tideway Tunnel: early review of potential risks to value for money.*

their advisers have not understood that effective competition proceeds from the right structure of suppliers and works in innovative, not predictable ways.[7]

The independence of the regulator has been overridden, making Ofgem an agent of ministerial whim. Nationalisation of regulators has cost Ministers less than nationalisation of suppliers, although the cost to the nation is much higher. The steps taken in the 1990s towards establishing a fruitful separation of powers[8] have been reversed.

Good intentions in the form of a desire to save the planet have led to our impoverishment. We need better analysis, greater transparency and more effective discussion of social and environmental issues, not Whitehall playing shops. Rupert Darwall provides us with the tools for such discussions in the area of energy and, in his policy lessons, points us towards better approaches.

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7 Littlechild, S. (2012), *Protecting customers or suppliers? A response to Ofgem's consultation on its Retail Market Review – Updated domestic proposals.*

8 Vibert, F. (2007), *The Rise of the Unelected: Democracy & the New Separation of Powers,* Cambridge.

1. THE IMPACT OF ENERGY MARKET REFORM ON COMPETITION

Electricity privatisation in 1988, the advent of retail competition ten years later and the demise of the generating duopoly gave Britain the appearance and reality of having one of the world's most liberalised electricity markets. Appearances outlasted reality. From the turn of the century, the electricity industry underwent profound structural change:

> *First*, vertical and horizontal consolidation led to the emergence of today's Big Six energy companies;[9]
>
> *Then*, Government interventions to support investment in renewables created increasingly severe market distortions.

Political concern mounted that competition isn't functioning, to the detriment of customers. The current market investigation by the Competition and Markets Authority is predicated on the

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9 See Darwall, R (November 2014), *How to run a country: Energy policy and the return of the State.*

assumption that competition can be made to work. In reality, competition in the electricity supply market is a sideshow. Based on segmental data set out in Annex I and summarised in Table 1, in 2013 only 9.1 per cent of Big Six's supply costs were directly incurred in supply (what Ofgem confusingly calls 'indirect costs') and 88.1 per cent of costs are in essence pass-through costs ('direct costs'). These pass-through costs comprise fuel (53.1 per cent), network and transmission (24.1 per cent) and Government-imposed obligations (13.2 per cent), the latter two in large part driven by Government mandates on generating mix.

Table 1: Big Six Electricity Supply Cost Structure

	Costs (£m)	As % total costs
Fuel	15,212	53.1%
Network	6,906	24.1%
Environmental & social obligations	3,771	13.2%
Other direct costs	82	0.3%
Sub-total: direct costs	25,971	90.7%
Indirect costs	2,560	8.9%
Depreciation & amortisation	113	0.4%
Sub-total: indirect costs	2,673	9.3%
Total	28,644	100.0%

Source: Ofgem (August 2014), *Energy companies' Consolidated Segmental Statements for 2013.*

If the competitiveness of downstream supply is therefore a sideshow, competition in upstream generation is centre stage. Massive Government interventions to subsidise near-zero marginal cost output raises a fundamental question over the continued functioning of the electricity market. As Professor David Newbery of Cambridge University, an adviser to the Department of Energy and Climate Change (DECC), observed when Parliament was debating Energy Market Reform (EMR)

> 'One of the main concerns with the proposed Electricity Market Reform is whether it represents a retrograde step, replacing market-driven investment decisions with a single, possibly state-controlled, buyer model. The deeper concern is whether liberalised electricity markets are compatible with a low-carbon electricity industry.'[10]

However, the policy analyses produced by the Coalition Government and its predecessor did not pose, let alone answer, Newbery's questions. In fact, they took the diametrically opposite approach of the privatisation policy makers in the late 1980s. The economic objective of privatisation was cost discovery, thereby promoting efficiency. Rather an unstated objective of policy since adoption of the renewables target has been to hide the full cost and operational implications of renewables.

Although the UK has been reluctant to quantify the full cost of renewables, in 2013 Germany's environment minister said that Germany's transition to renewable energy could cost up to one

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10 Newbery, D. (2012), 'Reforming Competitive Electricity Markets to Meet Environmental Targets,' *Economics of Energy & Environmental Policy* Vol 1, No 1, p.71.

trillion euros (£800 billion) by the end of the 2030s.[11] Instead of asking how much they cost, the principal policy challenge was framed as:

> *How do we attract enough finance to fund investment in renewables to meet Britain's target in the 2009 EU directive?*

This approach means that critical issues involved in the rapid adoption of renewables were not systematically examined:

1) The full, system-wide implications of subsidising renewables, in particular their impact on the profitability and financing of conventional generation needed to cover for the intermittent and unpredictable nature of wind power, were not considered before the policy was adopted;

2) Because of 1), the Government still has little idea of the full cost of renewables. Although on coming to office, the Coalition put in place a Levy Control Framework (section 6.2), its coverage is incomplete and it is not capable of preventing cost escalation above the pre-set cap.

As a result – again, as distinct from the experience with electricity privatisation – the policy framework is the outcome of piecemeal changes. This makes further changes all but inevitable, illustrating the self-defeating nature of EMR as it compromises the objective of minimising political risk and giving investors certainty.

Although ostensibly adopted in furtherance of decarbonisation, renewables undercut the EU's Emissions Trading Scheme (ETS).

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11 Mac Matzen, M. (2013), "German 'green revolution' may cost 1 trillion euros – minister", *Reuters*, 20 February.

Because the renewables target was adopted without reducing the cap on CO_2 emissions, the effect of the renewables target is to displace emissions, not reduce them. For example, lower German emissions can be taken up by Italian coal-fired power stations. The high costs and perverse outcomes of renewables policy place a question mark over its longevity. According to Newbery,

> 'there must be serious concern that once voters realise that the high cost of additional renewable electricity will not lead to any reduction in EU CO_2 emissions, they are likely to call for an end to costly renewables support.'[12]

[12] Newbery, D. (2012), "Reforming Competitive Electricity Markets to Meet Environmental Targets", *Economics of Energy & Environmental Policy* Vol 1, No 1, p.72.

2. THE PROBLEM WITH INTERMITTENT RENEWABLES

It is hard to understate the implications of the UK's growing exposure to wind for its electricity. According to the Royal Academy of Engineering, which is sympathetic to renewables,[13] it requires 'a fundamental shift in society's attitude to and use of energy.'[14] Success, the Academy says, depends on the ability to manage demand to reflect the output from wind, going on to note that despite increasing efforts to research demand management techniques (to match consumption to the variability of the weather), 'there is still much uncertainty on how effective it will be and at what cost.' So called 'smart grids' will be vital, the Academy says, but their potential and effectiveness at scale 'are yet to be proven.'[15]

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13 Royal Academy of Engineering (2014), *Wind Energy: implications of large-scale deployment on the GB electricity system*, p.58.

14 Ibid. p.4.

15 Ibid. p.55.

Electricity has a set of uniquely demanding characteristics:

- It cannot be stored, except to a limited extent, with batteries and pumped hydro, and that storage is limited and incurs a cost;
- Supply must respond almost instantaneously to demand;
- If too little is produced, there is a danger of degraded quality and, eventually, of power cuts, which are costly to users;
- Too much production can damage the transmission system, leading to wires becoming deformed or even melting;
- Failing to equalise demand and supply can also lead to changes in the frequency of the power supply – too high, and it can damage appliances; too low, equipment can underperform.[16]

Wind and solar technologies pose huge integration challenges. They are difficult to predict, particularly wind, which is highly variable – on gusty days, wind speeds can vary enormously over a few minutes or even seconds. According to Malcolm Grimston of Imperial College, London, low wind speed tends to be weakly correlated with high power demand (cold, windless winter evenings and hot, windless summer days).[17] Depending on how wind-generated electricity is connected to the grid, large

16 Grimston, M. (2014), "The full costs of generating electricity", *Journal of Power and Energy,* Vol. 228, No. 3, pp.357-358.

17 Ibid. p.360.

amounts of wind power can reduce system inertia and make it less stable.[18]

The UK already has one of the largest installed wind capacities in the world at 10.4GW. Wind capacity under construction and consented will nearly double this to 20.7GW, with the UK having the largest installed capacity of offshore wind in the world.[19] Wind power's intermittency, unpredictability and variability mean that UK electricity supply is moving from industrial production, where, like a factory, output can be precisely calibrated and controlled by varying the inputs, to arable farming, where output is heavily dependent on the weather.

In some ways, renewables are more problematic than farming:

- The need for agricultural output is less time-critical but its timing is more predictable than for renewables and electricity;
- Even worse, the variability of farm output does not have an automatic knock-on effect on industrial output, prices, profits and investment as it does with renewables.

When renewables account for a significant proportion of generating capacity, the whole electricity system becomes exposed to weather risk as it has to cope with what an OECD/ Nuclear Energy Agency (NEA) report calls 'random amounts of intermittent electricity.'[20] The uncertainty inherent in farming is one reason why governments end up heavily subsidising farmers.

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18 Royal Academy of Engineering (2014), *Wind Energy: implications of large-scale deployment on the GB electricity system*, p.33.

19 Ibid. p.19 & Table 2.1.

20 OECD/Nuclear Energy Agency (2012), *Nuclear Energy and Renewables: System Effects in Low-carbon Electricity Systems*, p.23.

The logic of exposing all electricity generators to weather risk implies that the Government subsidises all forms of electricity generation, something wholly unanticipated by policymakers. MIT professors John Deutsch and Ernest Moniz remarked in a 2011 report that policies to encourage renewables have been successful in promoting large-scale deployment, before observing:

> 'It is becoming clear that the total costs and consequences of these policies were not fully understood.'[21]

In other words, politicians adopted pro-renewables policies with their eyes wide shut. Britain's target of deriving 15 per cent of its total energy consumption from renewables was agreed before the system-wide consequences had been analysed. Energy policy has been trying to play catch-up ever since. Renewables policy is truly a leap into the dark.

Policy Lesson #4

Setting a target before analysing the costs, operational implications and likely unintended consequences without considering alternatives, constitutes the foundational error in the entire process from which, in one way or another, subsequent errors flowed.

2.1 Impact on conventional generators

Wind power is a highly capital-intensive way of generating electricity as it relies entirely upon the substitution of capital for

[21] MIT Energy Initiative (2011), *Managing Large-Scale Penetration of Intermittent Renewables*, p.3.

fuel inputs.[22] This cost structure means wind has very low variable costs. Effectively the marginal cost is zero, although the average cost is, of course, far higher than for gas. At optimal wind speeds, the wholesale market is flooded with zero marginal cost power, forcing power generators with higher variable costs to rapidly reduce their output. This has adverse price, volume and cost impacts for investors in conventional thermal plants such as coal and gas:

- They have lower load factors, thus increasing the break-even price of electricity needed to recover capital costs;
- Wholesale electricity prices are lower and less predictable;
- They lose much of the benefit of the natural hedge whereby the higher input costs of say natural gas are passed through to wholesale prices;
- Cycling thermal plants to balance changes in wind power imposes higher maintenance costs (and offsets some of the presumed reduction in CO2 emissions from intermittent renewables);
- When thermal plants cycle – ramping up and down – and are operated at partial loads, fuel efficiency declines and the emission-intensity of output rises.

Wind and solar power investors are paid for the electricity generated by the weather (and in certain circumstances, are paid not to produce – a further feature that subsidised energy production shares with the Common Agriculture Policy). They do

[22] Hughes, G. (2012), *The Performance of Wind Farms in the United Kingdom and Denmark* (Renewable Energy Foundation), p.21.

not have a symmetrical obligation to supply, thereby transferring weather risk and system costs to the rest of the system. The system impacts of renewables mean, for example, that subsidies for nuclear power need to be higher and consumers also end up supporting Combined Cycle Gas Turbine (CCGT) and coal-fired power stations to keep the lights on.

2.2 The findings of Project Discovery

A 2009 report by consultants Pöyry highlighted the challenge faced by investors in the British energy market.

> 'If significant penetration of renewables is achieved, power stations which are built now will face a future of not only far lower load factors … but also dramatically increased uncertainty of revenues than at present.'[23]

The short version of this message was: renewables risk killing off investment in thermal generating capacity. Pöyry's report eas exactly right, load factors for CCGT have more than halved – falling from 71.0 per cent in 2008 to 30.4 per cent in 2012.[24]

In early 2009, Ofgem launched a study to assess the prospects for security of energy supplies over the next 10-15 years. Project Discovery's interim report (October 2009) avoided directly addressing the cost implications of renewables for consumers. In line with government and EU policy, Ofgem assumed consumption would reduce over time as prices rose and even suggested that 'significant upfront investment in renewables today might lead to cheaper energy bills later, since customers

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23 Henney, A. (2011), *The British Electric Industry 1990-2010: The Rise and Demise of Competition*, p.311.

24 Ibid. Table 4.1.

will to some extent avoid paying for (potentially increasingly expensive) fossil fuels.'[25] Of course, the higher the cost of fossil fuels, the lower the cost of decarbonisation. Conversely, shale gas and lower coal prices make decarbonisation more expensive. Either way, what consumers can't avoid paying for, however little electricity they use, is the much higher capital requirement of wind power.

According to Project Discovery, the capital cost of onshore wind is double that of CCGT. For offshore wind, the capital cost per kW is nearly five times higher – before accounting for the thermal (gas and coal) capacity needed to cover wind intermittency. For Project Discovery, Ofgem applied de-rating factors to adjust the nameplate capacity of different generation types to reflect better the probable contribution each is likely to make to meet peak demand. Therefore, wind assets have a significant de-rating to reflect the lower average availability and risks of correlated periods of low output.[26]

Table 2 below applies these to illustrate the capital cost for onshore and offshore wind compared to CCGT to meeting peak demand on the basis that CCGT is used as dispatchable capacity (i.e. which can be turned on and off when required). To derive the overall capital cost for each plant type, it applies Ofgem's de-rating factors, assuming the balance is met with additional CCGTs.

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25 Ofgem (2009), *Project Discovery Energy Market Scenarios*, p.12 & p.51.

26 Ibid. p.39.

Table 2: Capital Cost per kW adjusted for Ofgem 2009 De-rating Factors

Plant type	Cost per kW (£)	De-rating factor (%)	Cost per kW of additional (dispatchable) capacity (£)	Total cost per kW (£)	Capital cost per kW as multiple of CCGT
CCGT	600	95	32	632	n/a
Onshore wind	1,200	15	510	1,710	2.7
Offshore wind	2,800	15	510	3,310	5.2

Source: Ofgem (2009), Project Discovery Energy Market Scenarios, p.90.

2.3 Cost and capacity implications

Since 2009, the relative cost of CCGTs to wind has fallen. DECC's 2013 estimate of the 'overnight' capital costs of onshore wind (i.e. excluding capitalised interest) at £1,600 per kW compares to £610 per kW for CCGT. Thus the capital cost of onshore wind has risen from being twice as expensive as CCGT to 2.6 times in just five years. The costs of offshore wind have also worsened. Based on analysis of actual build costs in the US and adjusting for higher UK offshore construction costs, Edinburgh University's Professor Gordon Hughes estimates 2013 prices would be at least £3,300 per kW compared to Ofgem's 2009 assumption of £2,800 per kW – a rise of 17.9 per cent.[27]

The need for intermittent renewable capacity to be twinned with dispatchable capacity drives a colossal investment requirement.

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27 Gordon Hughes email to author, 3 September 2014.

For the same peak electricity demand of 60GW as today, which was met by 85GW of capacity in 2011, the Government estimates the UK will need 113GW of capacity in 2025 – an increase of 28GW. Because the Government did not seek a derogation from the EU Large Combustion Plant Directive, 12GW of coal-fired capacity will also need to be replaced plus 10GW of time-expired nuclear capacity, implying a total requirement of 50GW of new capacity, of which two thirds (33GW) is planned to be renewables.[28]

Thus meeting the UK's renewable target requires 28GW more capacity than if peak demand was met conventionally. Assuming a 50:50 split between onshore and offshore wind, on the basis of Project Discovery's numbers, this implies an additional capital cost of £56 billion. The additional cost of deploying the extra 5GW of renewables (33GW less 28GW) instead of CCGTs is £7 billion, implying a £63 billion extra cost of renewables to provide the same peak capacity as from conventional power stations.

Wind and solar also require heavy extra investment in transmission infrastructure. For onshore wind, proposed reinforcements of the transmission grid are of the order of £8 billion, which represents a doubling of the Regulatory Asset Value of National Grid's existing transmission network. This extra capital cost has a material impact on the underlying (and disguised) economics of wind, particularly in remote, windy locations. According to electricity industry expert Alex Henney, the implication is the cost of transmission of Scottish wind power is

[28] Grimston, M. (2014), "The full costs of generating electricity", *Journal of Power and Energy*, Vol. 228, No. 3, Table 1.

of the order of £500 per kW – making the capital cost of onshore wind 3.7 times higher than that of CCGT.[29]

Connecting offshore wind is even more expensive. The UK government estimates that it will cost £15 billion to connect the first three rounds of offshore sites and the British Wind Energy Association has estimated that it will need some 7,500km of High Voltage Direct Current (HVDC) cabling by 2020, compared to HVDC global production of around 1,000km a year.[30] With Germany needing over 8,000km of new upgraded transmission lines, supply bottlenecks could well lead to substantial cost escalation.[31]

29 Henney, A. (2011), *The British Electric Industry 1990-2010: The Rise and Demise of Competition*, p.322.

30 Ibid. pp.327-328.

31 Ibid. p.361.

3. SYSTEM COSTS OF RENEWABLES

The 2012 OECD/NEA report provides a systematic analysis of the system costs of integrating renewables, estimating total grid-level costs for six generating types across six countries at 10 per cent and 30 per cent penetration level for each technology (Table 3 on adjacent page). These costs come on top of the higher plant-level costs, including levelised costs (estimated unit cost of electricity generated over a plant's life-cycle), which are the focus of much misleading media commentary on the imminent cost-competitiveness of renewable technologies.

To put these numbers into context, according to Energy UK Trade Association, the average forward wholesale price of electricity for the year starting April 2013 was £51.80 per MWh.[32] As can be seen from the table, the system costs of nuclear, coal and gas range from 35p/ per MWh for gas to £1.96 per MWh for nuclear (a mark-up of less than 4 per cent on the wholesale price).

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[32] UK Energy (2014), *Wholesale Electricity Market Report – Winter Season to end January 2014,* p.2.

Table 3: UK grid-level system costs ($/MWh)

Technology	Nuclear		Coal		Gas		Onshore wind		Offshore wind		Solar	
Penetration level	10%	30%	10%	30%	10%	30%	10%	30%	10%	30%	10%	30%
Back-up costs (adequacy)	0.00	0.00	0.06	0.06	0.00	0.00	4.05	6.92	4.05	6.92	26.08	26.82
Balancing costs	0.88	0.53	0.00	0.00	0.00	0.00	7.63	14.15	7.63	14.15	7.63	14.15
Grid connection	2.23	2.23	1.27	1.27	0.56	0.56	3.96	3.96	19.81	19.81	15.55	15.55
Grid reinforcement & extension	0.00	0.00	0.00	0.00	0.00	0.00	2.95	5.20	2.57	4.52	8.62	15.18
Total grid-level system costs	3.10	2.76	1.34	1.34	0.56	0.56	18.60	30.23	34.05	45.39	57.89	71.71
Total grid-level system costs (£/MWh)	1.96	1.74	0.85	0.85	0.35	0.35	11.74	19.07	21:48	28.64	36.52	45.24

Source: OECD/Nuclear Energy Agency (2012), Nuclear Energy and Renewables: System Effects in Low-carbon Electricity Systems, Table ES.2. USD translated at $/£=1.585.

The contrast with renewables is stark:

- **Renewables impose much higher grid-level system costs.** Variable renewables generate system effects that are, in the words of the report, 'at least an order of magnitude greater than those caused by dispatchable technologies.'[33] For solar power in the UK, system costs at 30 per cent penetration of £45.24 per MWh are two orders of magnitude greater than that for gas, representing a near 90 per cent mark-up on the current wholesale price.

- **There are marked diseconomies of scale to deployment of renewables.** Whereas nuclear power exhibits grid economies of scale and the costs of coal and gas are unchanged at scale, all three renewable technologies show marked diseconomies of scale in terms of total grid-level systems costs. In absolute terms, in the UK, the three exhibit similar unit cost increases (£7.16 to £8.72 per MWh) as penetration rises from 10 per cent to 30 per cent. Thus renewables get even more expensive the more they are deployed.

Higher grid-level system costs represent only part of the increase in electricity costs caused by wider deployment of renewables and, as the OECD/NEA report notes, the plant-level generation costs of renewables are 'still significantly higher than those of conventional technologies.'[34] Table 4 brings together the extra plant-level and grid-level system costs for onshore and offshore wind at 10 per cent and 30 per cent penetration. Whereas higher plant-level costs are recognised with overt subsidies, the extra

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[33] OECD/Nuclear Energy Agency (2012), *Nuclear Energy and Renewables: System Effects in Low-carbon Electricity Systems*, p.13.

[34] Ibid. p.131.

grid-level system costs are hidden, understating the true cost of generating electricity from renewables.

Table 4: Increases in annual cost of electricity supply for the UK due to the integration of Onshore and Offshore Wind ($m)

	Reference case (conventional mix)	**10% penetration**		**30% penetration**	
		Onshore wind	Offshore wind	Onshore wind	Offshore wind
Annual cost	35,312				
Increase at plant-level		541	1,403	1,623	4,209
Grid-level system costs		668	1,223	3,258	4,891
Total increase		1,209	2,626	4,881	9,100
Percentage increase on conventional mix (%)		3.4	7.4	13.9	25.8

Source: OECD/Nuclear Energy Agency (2012), Nuclear Energy and Renewables: System Effects in Low-carbon Electricity Systems, Table 4.2B.

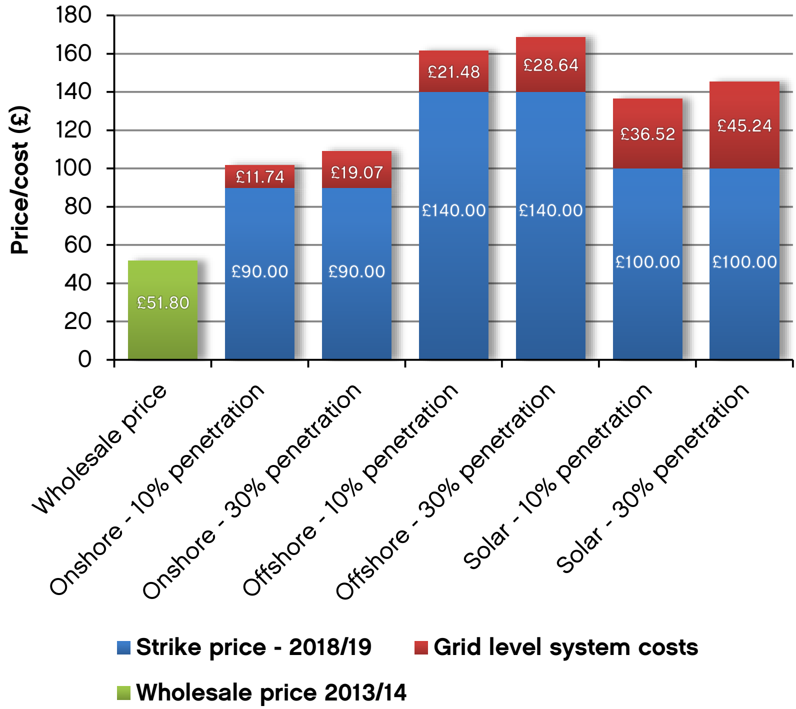
Table 4 shows that, except for offshore wind at 10 per cent penetration, the increase in (hidden) system costs of onshore and offshore wind at 10 per cent and 30 per cent penetration levels exceed the increase in plant-level costs, for which the subsidy and support regime is explicit. This implies that the cost of policies to encourage investment in wind capacity is likely to be at least double the sticker cost as they move above 10 per cent penetration.

Overall, the study estimates the total increase caused by integrating renewables ranges from between 3.4 per cent (10 per cent penetration of onshore wind) to 25.8 per cent (30 per cent penetration of offshore wind). On the basis of a 50:50 split between onshore and offshore wind and combined 20 per cent penetration, this implies around $4.4 billion (£2.8 billion) of annual cost for wind power, an increase of around 12.6 per cent.

3.1 Cost-push impact of renewables

The cost-push impact of renewables on electricity prices is illustrated in Figure 1, which layers on annual grid-level system costs from Table 3 to the 2018/19 strike prices announced by DECC against the 2013/14 wholesale price of £51.80 per MWh.

Figure 1: Renewable strike prices and grid-level system costs (£/MWh)



Source: OECD/Nuclear Energy Agency (2012), Nuclear Energy and Renewables: System Effects in Low-carbon Electricity Systems, Table ES.2. USD translated at $/£=1.585; DECC (2013), Investing in renewable technologies – CfD contract terms and strike prices, Table 1; UK Energy (2014), Wholesale Electricity Market Report – Winter Season to end January 2014, p.2.

The chart also provides a rough and ready cross-check on the generosity of the price supports given to renewables investors. On the basis of the OECD/NEA estimate in Table 4 on page 19, the ratios of additional plant-level costs to grid-level costs is roughly 1:1 for onshore and offshore wind at 10 per cent penetration, rising to 1:2 for onshore wind at 30 per cent penetration (i.e. the increase in grid-level system costs should be twice that of the increase in plant-level costs). Taking the 2013/14 wholesale price of £51.80 per

MWh as the benchmark, the increase in plant-level costs from wind at 10 per cent penetration (the £90 strike price less the £51.80 wholesale price) is over three times that of the £11.74 increase in grid-level costs. If the OECD/NEA analysis is accurate, it implies the DECC strike prices are exceptionally generous and the rapid deployment of onshore wind suggests investors are being handsomely over-incentivised.

3.2 Incentive and market-distorting effects

All too often, policy interventions create unintended distortions that require further interventions. The electricity market is especially vulnerable because, as the OECD/NEA study notes, it is one interconnected system, where all production and consumption pass through the same transmission lines and everyone's production and consumption instantaneously interact with everyone else's.[35] The influx of random amounts of heavily subsidised intermittent electricity has profound effects on the market. It depresses the profitability of existing conventional and nuclear generators, and prospective returns from investing in the replacement capacity necessary to maintain continuity of supply are lower and more difficult to predict.

There are even examples of negative wholesale prices in Denmark, Germany, Canada and California, i.e, at these times, their output is worse than worthless – like garbage, someone has to be paid to take it away. At periods of low demand in systems with high renewables penetration, there are extended periods in which the electricity produced by renewables exceeds demand.[36] 'These distortions are prognosticated to become even more

[35] Ibid. p.34.

[36] Ibid. p.132.

pronounced in the future as new wind and solar capacities are being installed,' the OECD/NEA study notes.[37]

The study delineates two linked effects of renewables on the market and on incentives to invest in dispatchable capacity:

- **Compression effect.** Investors in conventional generating assets are exposed to lower and more volatile wholesale prices, an effect amplified by reduced load factors when weather conditions are favourable for renewables;

- **Pecuniary effect.** Because wind and solar investors are subsidised (mostly in the form of guaranteed prices and forced buyers for their output), they are isolated from the effects of their output on the market price whereas conventional producers will never affect the renewable producer, who will generate electricity as a function of the weather, regardless of market conditions. This asymmetric treatment, the study notes, 'will lead to underinvestment in dispatchable technologies and thus increase security of supply risks at times of low renewable production due to unfavourable meteorological conditions.'[38]

The impact of the compression effect on dispatchable output depends on the variable cost structure of the dispatchable technology. Based on data from the French electricity market, the OECD/NEA analysis shows that for 30 per cent wind penetration, gas-fired plants experience an overall load reduction of about 80 per cent (87 per cent in the case of CCGT), whereas the reduction for coal is about 60 per cent relative to production without

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37 Ibid. p.37.

38 Ibid. p.37.

renewables. Thus perversely of all fossil fuels, renewable subsidies displace the most efficient in terms of carbon dioxide emissions and, in relative terms, benefit coal. (In the short term, nuclear is less affected, with a load reduction of less than 20 per cent).[39]

Aside from the implications of this analysis for the efficacy of renewables in actually reducing CO_2 emissions, the distortion of wholesale prices raises the question as to whether the wholesale market is so severely damaged as to be functionally worthless. Indeed, the OECD/NEA report asks whether the wholesale electricity market is 'the relevant instrument for matching supply to demand and for co-ordinating investment decisions.'[40] The growing wedge between wholesale prices and the income received by investors in renewable capacity puts a question mark over 'the very role of the marketplace to provide adequate signals for power generation investors,' the report states.[41]

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39 Ibid. p.135.

40 Ibid. p.37.

41 Ibid. p.33.

4. MACRO-ECONOMIC IMPACTS

After a prolonged period of falling living standards and the UK running large current account deficits, expanding renewables has wider economic impacts. In addition to the direct squeeze on living standards from higher electricity bills are indirect effects of higher energy costs on businesses, which are passed through to consumers in higher prices of goods and services.

In terms of competitiveness, the UK is not well-positioned to absorb the cost increases imposed by expanded renewable capacity. According to the OECD/NEA analysis, the UK has the highest unit cost electricity (excluding renewables) of the six nations analysed in the report – the others enjoying a cost advantage ranging from 17.9 per cent in the case of Germany to 35.1 per cent for South Korea (Table 5).

Table 5: Cost of electricity supply – conventional mix

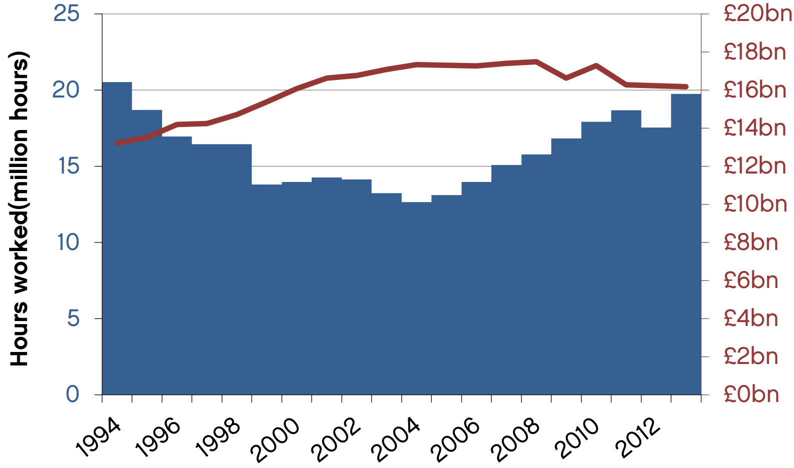
	Cost per MWh ($)	Cost advantage over the UK (%)
UK	98.3	n/a
Germany	80.7	17.9
Finland	75.9	22.8
France	73.7	25.0
US	72.4	26.3
South Korea	63.8	35.1

Source: OECD/Nuclear Energy Agency (2012), Nuclear Energy and Renewables: System Effects in Low-carbon Electricity Systems, Table 4.7.

The UK has also experienced an unprecedentedly long period of labour productivity weakness. Sector data suggest that the energy sector is partially responsible for the UK's poor productivity. Between 1994 (the earliest year for which consistent data are available) and 2004, the Electricity, Gas, Steam and Air Con (as defined by the Office for National Statistics) recorded huge gains in labour productivity. Output rose by 31.1 per cent and hours worked fell by 38.4 per cent, leading to a more than doubling in output per hour.

After 2004, those gains began to be reversed: From 2004 to 2013, hours worked rose 56.1 per cent whilst output declined by 6.7 per cent, leading to a 40.2 per cent decline in output per hour (Figure 2). By contrast, the decline in output per hour from 2008 to 2013 for the whole economy was only 3.2 per cent.

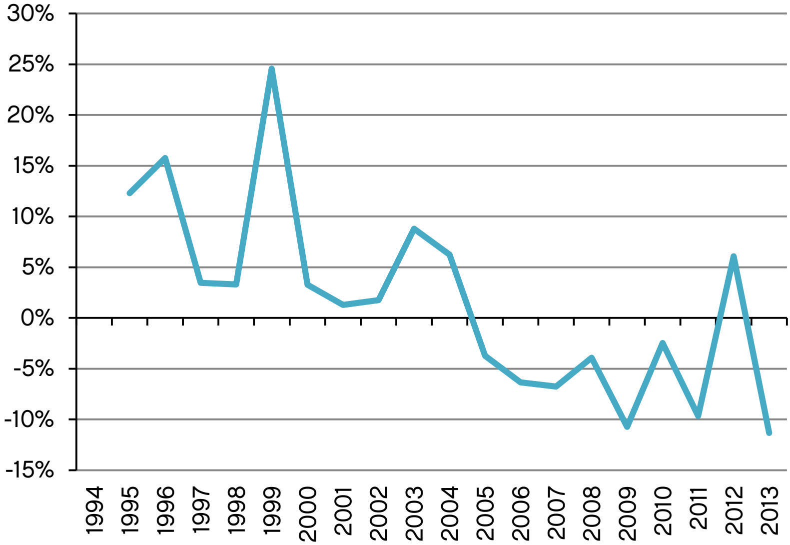
Figure 2: Output and Hours for Electricity, Gas, Steam and Air Con. (Industry D) at constant prices



Source: Office for National Statistics.

Despite billions of pounds of capital (which in a competitive market would indicate capital being substituted for labour), there was only one year (2012) in the nine years since 2004 when labour productivity growth was positive (Figure 3). As a result of the sector's negative productivity growth, by 2013 three quarters of the productivity gains recorded between 1994 and 2004 had been lost.

Figure 3: Electricity, Gas, Steam and Air Con - Annual percentage change in labour productivity



Source: Office for National Statistics.

Thus recent productivity performance of the energy sector has been disastrous. The 40.2 per cent decline in energy sector labour productivity since 2004 warrants analysis to assess the reasons causing it and the energy sector's contribution to explaining the conundrum of the UK's poor labour productivity. However, the evidence strongly suggests that the sector and the huge capital requirement caused by renewables are detracting from UK total factor productivity and therefore harming the economy. Due to energy policy, diversion of capital into less productive investment in renewables will tend to lower the rate of productivity growth, the growth in living standards and act as a drag on the UK's economic performance.

5. HOW WE GOT HERE: ASKING THE WRONG QUESTIONS

A consistent pattern of all policy appraisals conducted by the current and previous governments is to underplay, or even ignore the implications of swamping the wholesale market with heavily subsidised intermittent energy. Policy analysis under both the Labour and Coalition governments has failed to ask the right questions:

> *'What are the system-wide operating and cost impacts of integrating large amounts of intermittent electricity?'*
>
> *'Can the market survive the heavy subsidisation of near zero marginal cost capacity and remain an efficient signal setter?'* and
>
> *'What is the best way of minimising the cost to consumers of political risk?'*

As noted above, instead the challenge was primarily viewed as one of funding:

'How do we induce private sector investors to fund the huge increase in renewable capacity required to meet the UK's target?'

Because these issues were not systematically analysed, however unwelcome the answers might be, policy evolved in a piecemeal, patch-and-mend fashion that has worsened the problems it was trying to solve:

- The policy framework is subject to change, creating additional investor risk and uncertainty.
- As long as the problem is not fully scoped, the full costs of renewables will not be known, will not be controlled and be controllable.[42]
- Future security of energy supplies is imperilled because of the lack of investment in CCGT dispatchable capacity in a framework where genuine market signals are being replaced by a patchwork of policy interventions.

5.1 Policy Appraisal Stage One – Post-Project Discovery

In February 2009, Ofgem released its Project Discovery assessment. As the sector regulator, Ofgem should have been better placed than Whitehall departments to expose the fundamental issues created by the influx of renewable capacity. Its headline conclusion did catch Whitehall's attention, identifying a number of specific concerns that led Ofgem to conclude that

> 'there are reasonable doubts as to whether the current arrangements will deliver security of supply and

[42] The Levy Control Framework, discussed in Section 8.2 below, only caps the cost of one element.

> environmental objectives, at least not without consumers paying substantially more than they would otherwise need to.'[43]

First on its list of concerns was the cost and availability of finance, noting that

> 'uncertainty surrounding future carbon prices and subsidy levels are key risk factors facing investors. A perception of heightened policy and uncertainty, particularly given the long term nature of the investments required, may also push up the costs of financing them.'[44]

However, it thought that this higher cost of capital would disproportionately disadvantage low-carbon technologies and that uncertainty around future carbon prices would encourage investment in CCGT capacity, making decarbonisation over the longer term more difficult. Ofgem did concede, however, that additional CCGT capacity might be needed during the latter part of the decade, pointing to what the OECD/NEA report calls the compression and pecuniary effects and dubbed by Ofgem consultees as the 'missing money' effect:

> 'As an increasing proportion of the market receives revenues via subsidies this will place downward pressure on the profitability of gas powered generation and thermal plant will operate at lower load factors to accommodate the variable output patterns of wind and other renewables. Flexible thermal plant will increasingly

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[43] Ofgem (2010), *Project Discovery: Options for delivering secure and sustainable energy supplies*, p.14.

[44] Ibid. p.16.

> rely on either [sic] high prices in periods of system tightness to make an adequate return.'[45]

Ofgem expressed concern that electricity prices might not rise sufficiently during periods of scarcity, presenting 'a material risk to security of supply.' [46] As the UK moved to a system with a growing penetration of renewables,

> 'it will become increasingly important that the short term price signals lead to the most efficient dispatch of the market and elicit the necessary responses on both the supply and demand sides when periods of low renewables output coincide with periods of high demand, or when the supply/demand balance shifts rapidly and unexpectedly.'[47]

Thus Ofgem was betting that energy security could be assured by transferring weather risk to potential investors in CCGT and other dispatchable capacity on the basis of them guessing correctly the level and fluctuating duration of peak electricity prices years into the future. Without asking how investors might do this, as Project Discovery's top key message, Ofgem stated that electricity supplies could be maintained 'provided that market participants respond adequately to market signals broadly as they have in the past.'[48] In other words, Ofgem was expecting the market to find a cure for the profound market distortion created by government interventions in the energy

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[45] Ibid. p.18.

[46] Ibid. p.10 & p.19.

[47] Ibid. p. 9.

[48] Ibid. p. 11.

market in order to insulate renewables investors from the costs and risks they impose on the system. Ofgem is to be faulted for giving policy makers false reassurance based on a continuation of market responses when market conditions were being severely distorted by Government policy.

Although Ofgem put heightened risk/perception of risk at the top of its specific list of concerns, it shied away from asking the key question:

> *'Why should private investors be better at managing political risk than the Government?'*

Instead, Ofgem set out five possible policy options, the most radical being a central energy buyer. But none of them changed the allocation of political risk arising from doubts about the political sustainability of high and rising electricity prices between the party creating the risk (the public sector) and the parties expected to manage and price it (private investors).

One month after the publication of Project Discovery, shortly before the 2010 election, the Brown Government produced a joint Treasury/DECC *Energy Market Assessment.* Following Ofgem's lead, the Treasury and DECC mistakenly thought the real problem was attracting investment into renewables, believing such investment was less attractive than in gas-fired capacity.[49] 'Investment in low-carbon generation is the central issue,' the *Assessment* asserted and expressed anxiety that volatile gas prices would lead to periods of low electricity prices during the life of any low-carbon investment when 'the electricity generated cannot be sold at a price that covers the costs of investment,' i.e.

49 HMT/DECC (2010), *Energy Market Assessment* (March 2010), p.3.

the Treasury and DECC were far off the mark as to the impact of the compression and pecuniary effects on CCGT investment.[50] Thus the *Assessment* did not assess the implications of highly subsidised, low marginal cost renewable energy flooding the wholesale market on incentives to invest in dispatchable capacity.

On the critical issue of political risk, the *Assessment* promised more than it delivered. It acknowledged an enhanced role for what it called 'the strategic state' and mentioned the possibility of 'changing the balance of delivery between the private and public sectors and using the public balance sheet to support the financing of investment.'[51] Having raised it, this possibility was not systematically compared to other options; indeed, it wasn't put forward as an option at all. Of the *Assessment's* five options, the most radical was Ofgem's single buyer agent.

Neither did the *Assessment* systematically analyse the problem of political risk. One of the five options (regulate to limit high carbon generation) was assessed as resulting in a high cost of capital, on the grounds that

> '[t]here is significant risk that investors would not have sufficient confidence that government would maintain the policy and allow prices to rise and remain at a sufficiently high level that makes low-carbon investments attractive.'[52]

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50 Ibid. p.19 & p.21.

51 Ibid. pp.3-4.

52 Ibid. p. 2.

In reality, this objection is common to all the options considered by the *Assessment:* Investors need certainty that a future government will not renege on policies that cause energy prices to rise. As long as investor returns are exposed to energy prices, which in turn are products of policy interventions manipulating those prices, investors are exposed to political risk. The higher the retail prices resulting from such interventions, the greater is the political risk.

The logical solution is for the public sector to finance and own investment in such assets. Instead, the *Assessment* indulged in policy jingoism, calling Britain's electricity system 'one of the most liberalised in the world', with 'strong, independent economic regulation' – features of the past, not the present.[53] Indeed, the key analytical weakness of the *Assessment* is its presumption that a properly functioning competitive market can co-exist alongside subsidised renewable capacity. Thus it dismissed a central buyer option because it would have to take decisions on optimum levels of capacity and generation mix

> 'which may not be straightforward. The agency's decisions are important because it would control all investments through their tendering process … [T]here is a high risk that the agency may not be as well placed as suppliers in a competitive market to correctly determine the need for generation investment.'[54]

5.2 Policy Appraisal Stage Two – Electricity Market Reform

Ironically the Coalition took energy policy in the statist direction that its Labour predecessor had hinted at, but feared to go. In its

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53 Ibid. p.32.

54 Ibid. pp.35-36.

July 2011 EMR White Paper, the Coalition Government took two decisive steps towards state control:

- Adoption of the central buyer model, which had been rejected in Labour's final months; and
- Creation of a government-run Capacity Market.

Energy Secretary Chris Huhne's White Paper was less than forthcoming about the real reason why the latter was deemed necessary, claiming that it was due to the 'unprecedented nature of the challenge' and blaming the expectation of price caps for the 'missing money' at times of system tightness.[55] There was more than an element of political dissimulation in this – consumers do not see peak wholesale prices, but are exposed to rising prices caused by the costs of renewable capacity.

By 2012, DECC was more open about the real reasons for having a Capacity Market, even if it had to blame the market rather than its own policy:

> 'In theory, a perfectly functioning energy market should provide sufficient incentives for investment in new capacity. In this case a Capacity Market should not bring forward additional capacity to what the market would have anyway provided and so should have a minimal impact on prices and bills.
>
> 'In practice we think there is a risk of market [sic] failure in the current GB market. Incentives for investment in new capacity may be insufficient as electricity prices cannot

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55 DECC (2011), *Planning our electric future: a White Paper for secure, affordable and low-carbon electricity, CM 8099,* p.9 & p.66.

> rise sufficiently at times of scarcity (the "missing money" problem), and because flexible plants with higher running costs will run less often in a system with more intermittent (wind) and inflexible (nuclear) low carbon generation. In this environment a Capacity Market could have a small impact on bills.'[56]

Thus with EMR, energy policy reached the endpoint in its journey from the market to state control, where the Government or its agent:

- Sets prices for low-carbon generation;
- Decides on the overall level of generating capacity and determines the mix of generating technology.

As a result,

- All forms of electricity generation deemed part of the Government's strategy will end up supported by subsidies in one form or another, i.e. investor returns are dependent on the maintenance of those support arrangements; and
- Prices are not the outcome of competition but are driven by government policy.

An additional feature of EMR is its treatment of planned cuts in consumption, what it calls Demand Side Response (DSR) as equivalent to increases in capacity. Dependence on intermittent renewables makes provision of peak capacity more expensive as the need to balance peak loads becomes more frequent and less predictable. Whilst it is common for large energy users to benefit

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56 DECC (2012), *Electricity Market Reform: Policy Overview*, Annex C, p.15.

from the lower prices offered with interruptible supply contracts, EMR takes this to a new level by encouraging them to bid in the Capacity Market auctions.

In this sense, DSR represents the *reductio ad absurdum* of renewables policy: by building weather risk into electricity supply, it turns customers into suppliers; it transforms the electricity sector from being an enabler to a disabler of economic activity; by increasing the cost of supplying peak electricity, it pays businesses to stop producing and workers to stop work. All in all, vastly increasing the exposure of the economy to the variability of Britain's weather is an eccentric response to meeting the UK's productivity challenge.

5.3 Implications of the Capacity Market auction

In the event, the first Capacity Market auction, held in December 2014, resulted in a damp squib for DSR, which was provisionally awarded less than 0.4 percent of the total capacity being contracted.[57] Worse still, new build capacity amounted to only 2.6GW, little more than five percent of contracted capacity.[58] Furthermore, more than half the capacity (8.8GW of CCGT) that entered the auction then exited during it.[59]

This is a double disaster for Government policy:

- CCGT is meant to be the transitional generating technology and the Government wants more of it rather than less; and

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57 National Grid (18 December 2014), 'Provisional Auction Results: T-4 Capacity Market Auction 2014,' Table 1

58 Ibid. Table 1

59 Ibid. Table 6

- The Capacity Market failed to incentivise new investment on anything like the scale required.

With so much capacity slated for closure and the inherently unreliable nature of renewable capacity creating demand for additional dispatchable capacity, the Government faces a big problem. In the short term, it might be able to keep the lights on, but longer term Britain faces a capacity crunch. To avert it, a new approach will be needed.

6. THE WORST OF BOTH WORLDS

Having reached the destination of state direction of the electricity sector, the question arises as to whether EMR mix of state control and private ownership is optimal. It is, to invert the official ideology of the Communist Party of China, central planning with market features. Thus EMR is a novel hybrid – it preserves the forms of privatisation and it uses the language of competition and markets while the state acts as ringmaster.

In effect, EMR turns the electricity sector into a vast public/private partnership and its closest analogue is the Private Finance Initiative (PFI). Indeed, the structure of CfDs shares several key features typical of PFI projects:

- renewables developers must demonstrate significant financial commitment;
- there are timetables to complete and commission the asset;
- they have change of law provisions modelled on PFI contracts.

DECC also examined the case for a public/private sector profit sharing mechanism on project refinancing but rejected it on the grounds of lack of administrative resource.[60]

Unlike PFI, EMR exists in a twilight zone between the market and the public sector, where the state exerts control but is not financially accountable for a project's costs because these costs are borne by consumers not taxpayers:

- **Absence of cost control and effective accountability**. Unlike PFI, CfDs are not allocated by competition and the costs (the strike price) are decided by the Government, not the market, so the benefits of contestability are absent. Whereas the cost of PFI projects are assessed in value money appraisals in accordance with the Treasury Green Book, are scored as departmental spending, and subject to Treasury spending control, EMR costs are not systematically scrutinised and are not properly capped;
- **Absence of benefit from using private sector cost of capital**. The rationale for the PFI was that the higher cost of capital of private finance would be more than offset by giving the private sector freedom to lower total costs of delivering public sector specified outputs, as compared to the traditional public sector approach of prescribing inputs. Because under EMR, the public sector is prescribing inputs, it raises the question as to what are the efficiency benefits of using private sector capital to offset its higher cost which can't be delivered by a properly designed and executed procurement strategy.

60 DECC (2012), *Electricity Market Reform: Policy Overview*, Annex A, p.64.

Thus EMR incurs the cost of the market without its disciplines and combines that with the inefficiency of state direction without public sector financial control and accountability.

6.1 Poor cost control

There is always a high risk with target-driven policy objectives that considerations of cost and efficiency are subordinated to attainment of the target. As part of the Coalition Agreement, in 2010, the Government asked the Committee on Climate Change about the desirability of raising the target. In response, Lord Adair Turner, the then chairman of the Committee, advised against changing the target, informing the Government that it 'pushes the limits of what is likely to be feasible, and that a higher level of renewable generation is unlikely to be achievable.'[61] Significantly, in a 13-page document, there is not a single mention of the cost of attaining the 15 per cent target, or the cost of an even more demanding one. The issue was framed in terms of practicality, not cost.

Part of the explanation for renewables' poor cost visibility is that the total costs were not well understood. A bigger reason is the role of political and commercial incentives:

- The political consensus in favour of renewables and decarbonisation would be undermined if their costs were widely known;
- The scramble to install sufficient capacity to meet the 2020 target creates highly profitable opportunities for financial investors and other rent-seekers;

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61 Adair Turner letter to Chris Huhne, 9 September 2010.

- Although renewables depress the profitability of conventional generating capacity, tighter capacity margins raise prices and higher electricity prices benefit the Big Six's cost plus supply business;

- National Grid's underlying profit growth is driven by expansion of its Regulatory Asset Value and subsidising wind and solar capacity requires more grid infrastructure.

This situation is exacerbated because, in terms of the public/private sector demarcation, EMR is neither one thing nor the other. Thus EMR's costs are not subject to the discipline of the market whilst being beyond the reach of conventional public spending controls.

6.2 Levy Control Framework

In its first spending review, the Coalition Government decided to introduce a Levy Control Framework to monitor and control the costs of the levy-funded energy scheme overseen by a joint DECC/Treasury board. However, the Framework's coverage is not comprehensive and the controls are weak:

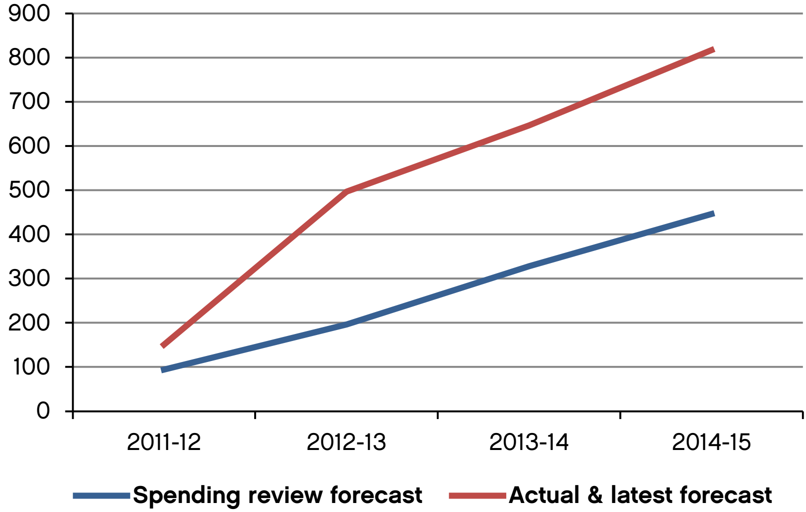
- It only covers plant-level renewable subsidies, so excludes higher grid and balancing and back-up costs. Based on the OECD/NEA analysis, this implies that at 20 per cent wind penetration, around half the overall costs of intermittent renewables are not covered by Levy Control Framework. Thus spending by National Grid on offshore wind connections is excluded, as are the costs of the Capacity Market mechanism;

- It excludes levy-funded schemes such as the Energy Companies Obligation (to fund energy efficiency schemes) and welfare schemes like the Warm Home Discount;

- Levy costs are difficult to control and, in the case of CfDs, impossible to control as their costs are driven by the divergence between pre-set CfD strike prices and future wholesale prices.

A November 2013 National Audit Office (NAO) report highlighted some of the deficiencies of the Levy Control Framework. It pointed to out-of-control spending on Feed-in Tariffs, where take up had been much faster than expected. DECC anticipates that in just four years, cumulative Feed-in Tariff spending will be £2.1 billion, nearly double the £1,064 million originally forecast (Figure 4).

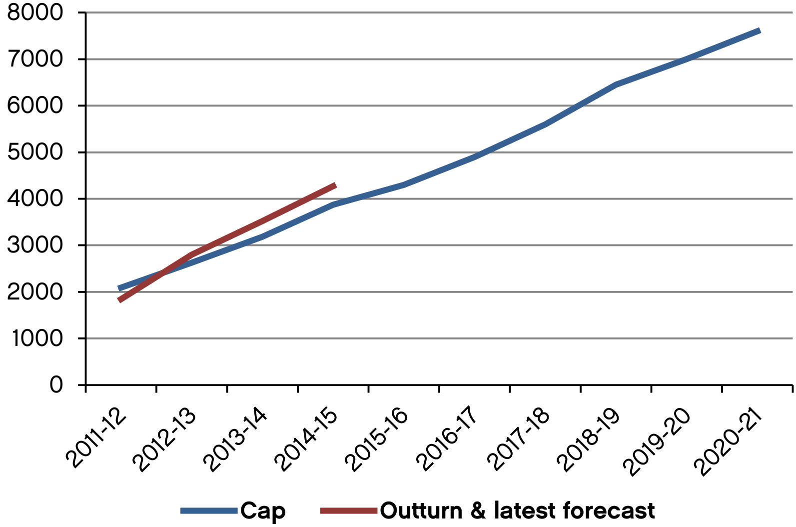
Figure 4: Feed-in Tariff spending – Spending review forecast vs. Outturn and latest forecast (£million nominal)



Source: National Audit Office (2013), The Levy Control Framework, Fig. 8.

Overall, spending covered by the Levy Control Framework is expected to rise from £1.8bn in 2011-12 to £7.6bn in 2020-21 (Figure 5). So far, cumulative spending has exceeded the Framework cap by 6 per cent, but in the last two years has been running at a 10 per cent overspend).

Figure 5: Levy Control Framework spending – caps vs. Outturn and latest forecast (£million nominal)



Source: National Audit Office (2013), The Levy Control Framework, Figs. 2 & 3.

For the ten years to 2020-21, DECC forecasts cumulative levy spending of £48.3 billion. By any standard, this is a large number, which predominantly goes to subsidise the capital costs of wind and solar capacity. Yet DECC has not presented a straightforward metric of the proportion of the capital cost of wind and solar capacity represented by this spending. Without such basic data, the public can have no idea whether the spending represents value for money or provides excess returns to renewables investors.

Under the Framework, the joint DECC/Treasury board is required to develop action plans if forecasts suggest spending will exceed the spending caps, 'with particular urgency if forecasts exceed caps by a specified extent – currently 20 per cent.'[62] However, the Government has stated that it is committed to maintaining support levels for existing investments where it has said it would do so. Unlike some jurisdictions, Spain being a notable example, it has ruled out making retrospective changes.[63] Over time, this position increasingly limits the Government's ability to control costs: once embedded, changes in costs are driven by factors outside its hands.

The NAO made a number of criticisms and recommendations of the Levy Control Framework:

- **Poor reporting.** DECC does not report aggregate actual spending against the Framework cap (limiting proper public and parliamentary scrutiny of costs to consumers and outcomes are not reported alongside costs).[64]

- **Lack of transparent forecasting.** Because CfD costs are a function of the number of contracts awarded and the difference between their strike prices and future prices, DECC should provide up-to-date and transparent forecasts of levy costs and outcomes.[65]

- **Failure to link spending to outcomes.** In its deliberations, the governance board has not 'strongly linked' spending to outcomes.[66]

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62 National Audit Office (2013), *The Levy Control Framework*, p.5.

63 Ibid. p.4.

64 Ibid. pp.9-10.

65 Ibid. p.9.

66 Ibid. p.10.

- **Incomplete coverage.** If DECC should decide not to extend coverage of the Framework to include the ECO and Capacity Market mechanism, 'it should explain how it will control the aggregate costs of consumer-funded schemes' and assess spending to attainment of policy objectives.[67]

Overall, the NAO warned that, as consumer-funded spending rises,

> 'the Department needs to assure Parliament and the public that it has robust arrangements to monitor, control and report on all consumer-funded spending, and the outcomes it is intended to secure.'[68]

6.3 Hiding the extra grid costs

The NAO report did not consider the hidden grid connection, extension and reinforcement costs of renewables. Based on the OECD/NEA numbers in Table 3 above, additional grid costs amount to between 37 per cent (onshore, 10 per cent penetration) to 52 per cent (offshore, 30 per cent penetration) of total grid-level system costs. (Grid costs for solar are even higher).

Rather than make the additional grid costs of renewables transparent, DECC chose to hide them. In 2009, Ofgem asked the Government to instruct it as to what criteria should be used for determining the terms for accessing the grid. If economic efficiency were the criterion, renewables projects would bear the associated grid costs. That way, the location of wind and solar capacity would be optimised. Locating wind farms on windswept hillsides in the Scottish highlands may generate more electricity,

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[67] Ibid. p.10.

[68] Ibid. p.10.

but they are more costly to integrate into the grid than sites closer to where demand for electricity is located. Instead, the Government's key criteria included incentives for investment in new generation and meeting renewable energy targets.[69]

After the election, DECC came down in favour of a 'connect and manage socialised cost' model, i.e. grid costs are to be shared among all users of the network and ultimately borne by consumers so that locational price signals are erased:

> 'DECC considers that socialising all constraint costs is the most appropriate approach to encourage new generation, sending a clear positive signal to all new investment without penalising new investment or investment in constrained parts of the network, particularly in Scotland, where we want to see good renewable energy resource harnessed.'[70]

Not only are the grid costs of renewables concealed, they are not known. When it set National Grid's current 8-year price cap, Ofgem excluded projects to strengthen and extend the network because of 'uncertainty around the timing and extent' of some large transmission projects.[71] Ofgem noted that transmission owners had identified some 'very large' projects totalling

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69 Henney, A. (2011), *The British Electric Industry 1990-2010: The Rise and Demise of Competition*, p.319.

70 DECC (2010), *Government Response to the technical consultation on the model for improving grid access*, p.10.

71 Ofgem (2013), *Guidance on the Strategic Wider Works arrangements in the electricity transmission price control, RIIO-T1,* p.4.

approximately £8 billion, but whether they will actually be needed depended on 'generation market developments.'[72]

Policy Lesson #5

A policy framework to encourage renewables that systematically conceals their costs will result in higher costs and higher electricity bills for the same quantum of renewable capacity.

6.4 Cost of capital and political risk

Driving down the cost of capital was a key objective of the 2011 EMR White Paper. It estimated that around £75 billion might be needed in new electricity generation capacity and £35 billion for electricity transmission and distribution. However, the cost of capital savings identified in the White Paper were hardly commensurate with the policy upheaval. Estimates prepared by DECC's economic consultants, Cambridge Economic Policy Associates (CEPA), suggested that using Contracts for Difference (CfDs) would result in only modest reductions in the cost of financing renewables compared to existing support mechanisms (primarily the Renewables Obligation).

72 Ibid. p.9.

Table 6: Estimated reductions in cost of capital from use of CfDs

Technology	Reduction due to CfD (percentage points)
Onshore wind	0.0 to 0.3
Offshore wind	0.5 to 0.8
CCGT with carbon capture & storage	0.1
Coal with carbon capture & storage	0.4
Nuclear	1.5
Biomass	0.5

Source: DECC (2011), Planning our electric future: a White Paper for secure, affordable and low-carbon electricity, CM 8099, Fig. 7.

According to the White Paper, these reductions in the cost of capital for all low-carbon technologies (i.e. including biomass, nuclear and carbon capture and storage technologies, as well as wind) from using CfDs total around £2.5 billion in the period 2010 to 2030.[73] The implied average annual saving of around £125 million compares to the £2.8 billion a year of additional costs incurred achieving 20 per cent wind derived from the OECD/NEA estimates report (see Section 6.4 above) – little more than a rounding error in the £110 billion of capital identified in the White Paper and associated financing costs.

[73] DECC (2011), *Planning our electric future: a White Paper for secure, affordable and low-carbon electricity*, CM 8099, p.41.

However, neither the 2011 White Paper nor the 2012 EMR policy overview explicitly addressed:

- What consumers would be getting in return for using private sector capital rather than using the Government's balance sheet to fund the capacity that the Government wants; and
- The impact of political risk on the cost of capital.

Instead, the CEPA analysis, published alongside the 2011 White Paper, focused on the tightness of existing sources of funding. The supply curve for finance was 'necessarily upward sloping,' CEPA observed. Because utility balance sheets were too small relative to the funding requirement, much of the finance would have to draw in new investors, including private equity and institutional investors, who do not have an operational interest in the investment or a strategic need to invest. On the supply of credit, CEPA noted that implementing Basel III would raise the cost of bank-financed projects.[74]

Such constraints do not apply to government debt. Experience since the 2008 banking crisis suggests that, in practice, the price of government debt barely changes with volume of issuance. Whilst official analyses have yet to quantify the benefits of using private sector capital over and above those which can be obtained from competitive procurement processes, using private sector capital incurs additional cost in the form of political risk.

In assessing the returns they need from investing in generating assets (their cost of capital), investors will incorporate an extra

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[74] CEPA (2011), *Note on Impacts of the CfD FIT Support Package on Costs and Availability of Capital and on Existing Discounts in Power Purchase Agreements,* pp. 5-6.

element to compensate for the risk that the arrangements are not maintained over the life of the asset. Thus consumers are being charged an insurance premium by investors to cover the risk to investors of a future government acting to reduce prices, but consumers only gain from paying the cost of investors' political risk premium if that's what a future government actual does.

Policy Lesson #6

Before adopting EMR, policymakers should have evaluated it against a public sector comparator so that the net cost/benefit of using private sector capital is identified and quantified, rather than being implicitly assumed.

7. THE CHOICE

Appearing before the House of Lords Select Committee on Economic Affairs in November 2013, Lord Lawson asked Dieter Helm: 'So if you were Secretary of State for Energy, what would you do now?' Helm replied,

> 'I would probably emigrate as quickly as possible; I would hate to perform such a task. The obvious answer is that when you are in a hole, the first thing you do is stop digging. Many things are currently being pursued that would make things significantly worse.'[75]

This dead-end has come about because policymakers ignored the likely effects of subsidising high fixed cost/near-zero variable cost intermittent energy on the functioning of the energy market before adopting the policy. Attempting to mitigate the damage by subsidising the provision of capacity, the Government is taking control of electricity generation, but not taking ownership of it.

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75 House of Lords Select Committee on Economic Affairs (2013, unrevised transcript), "Inquiry on the Economic Impact on UK Energy Policy Of Shale Gas and Oil", p.24.

This outcome represents the worst of both worlds. The American economist Thomas Sowell has written that profit is the price of efficiency;[76] with EMR, profit becomes the return from rent-seeking. In particular, the allocation of political risk to the private sector is deeply problematic and highly inefficient. In terms of consumer welfare, state control without state ownership only makes sense if a future government reneges on its commitment to making electricity more expensive, because otherwise consumers get nothing in return for being charged the cost of insurance against political risk. For this reason alone, EMR is inherently unstable and unlikely to be sustained.

There is an additional dimension which has already been touched on. As DECC acknowledges, CfDs represent public spending[77] and the levies used to fund them operate as a tax on electricity consumers.[78] Yet there is no parliamentary vote on the award of CfDs and Parliament has no say in the amount of levy taxation they give rise to. Indeed, CfDs have been designed to be beyond the purview of parliamentary assent and, being off-balance sheet, the Treasury is inevitably less concerned about the costs of EMR than if the policy were funded by taxation.

The inherent contradictions of EMR create additional uncertainty and political risk. EMR can most charitably be characterised as a work in progress, not a final destination. It lacks the structural coherence achieved by the designers of electricity privatisation. Policy design in the late 1980s had been facilitated by having all

76 Sowell, T. (2000), *Basic economics: a citizen's guide to the economy,* New York, NY: Basic Books, p. 75.

77 DECC (2012), *Electricity Market Reform: Policy Overview*, Annex A, p.28

78 Ibid. p.75.

the assets in the public sector, so there were no shifts in value from or to any particular group of private investors. Privatisation benefited from having a clean sheet of paper which is a superior approach to a series of incremental interventions when a sector is undergoing profound policy-induced change.

It would be understandable if concerns about value-shifting dissuaded policymakers from adopting a more radical approach, but it would overlook the value destruction of existing generating assets caused by subsidising renewables. In turn, this could explain the tolerance for so long of the vertically-integrated Big Six: super-profits on their supply business help offset losses on their thermal generating assets, thus helping preserve their balance sheets so they can play their part in funding renewables.

Using the credit card Ian Byatt describes in the foreword means higher electricity bills, worse value for money, poor transparency and attenuated accountability. The bottom line is if the state wants renewables, it should do it properly and get out its cheque book.

In reality, there are two choices:

(1) If meeting the UK's renewables target is the over-riding policy goal, then the most efficient solution is using the Government's balance sheet to directly finance investment in generating assets and buy out existing assets, i.e. full or partial renationalisation; or

(2) Abandoning the renewables target, isolating the market from the price-destructive effects of embedded renewable capacity and setting a clear path to return the sector to the market.

Either would result in substantially lower electricity bills than where they are heading under EMR and 2) would enhance the UK's economic performance.

7.1 Cost reductions from nationalisation

There are four ways in which nationalisation would cut costs compared to EMR:

- **Lower cost of capital.** EMR uses expensive private sector capital which has to price in political risk. Economists argue that the cost of capital should be derived from the project's risk, not investors' cost of funds and that investing at the State's cost of funds leads to a misallocation of resources. In the case of renewables, the Government has already decided capital allocation. Any resulting capital misallocation is exogenous to the way the investment is priced by the capital markets. Operating risk (the asset generates less electricity than forecast and costs more to maintain) remains, however the asset is financed. This analysis assumes a 33:67 split between capital (financing efficiency) and operating risk, implying that two thirds of the interest cost saving from using the state's balance sheet is retained to absorb operating risk. On this basis, the annual saving is £1.1-2.1 billion. These are an order of magnitude higher than the £125 million reduction implied in the 2011 EMR White Paper.

Box 1: Cost of capital illustrative assumptions

1. **Private sector cost of capital.** In its 2011 advice to the department, CEPA estimated a post-construction return of 'perhaps even as low as 8 per cent.' CEPA's more detailed estimates for CfD-backed investment imply a blended rate of 9.9 per cent for onshore and emerging offshore

wind.[79] However the reality, according to Professor Hughes, is that investors won't settle for much less than 10 per cent in real terms. DECC's first capacity auction only brought forward 2.9GW of near capacity build. It is difficult to derive estimates of investors' required returns for investment in CCGT capacity under EMR, which would have less risk so 8 per cent real would be more realistic, according to Hughes. This analysis assumes 10 per cent nominal cost of private sector capital, which is more likely to be too low than too high.

2. **Capital requirement.** Project Discovery estimated a £75 billion capital requirement for new generating capacity by 2020.[80] Since then onshore and offshore wind capital costs have escalated by 33 per cent and 18 per cent respectively. A 20 per cent increase implies a revised capital requirement of £90 billion by 2020.
3. **Annual financing cost.** 10 per cent nominal return implies electricity users paying an average of £4.5 billion a year for use of private sector capital up to 2020 and £9.0 billion a year thereafter, when 100 per cent of the assets are operational. Using a blended rate of 2.94 per cent for a mix of 10 and 30 year gilts, the average pre-2020 public sector financing cost would be £1.1 billion a year and £2.1 billion a year after 2020, implying annual savings of £3.2-6.4 billion, of which £1.1-2.1 billion are assumed to flow from improved financing efficiency by removing capital risk.

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79 CEPA (2011), *Note on Impacts of the CfD FIT Support Package on Costs and Availability of Capital and on Existing Discounts in Power Purchase Agreements,* p.7 & Table 3.2.

80 DECC (2011), *Planning our electric future: a White Paper for secure, affordable and low-carbon electricity*, CM 8099, p.6, fn.3.

- **Elimination of the costs of competition**. Nationalisation makes apparent what EMR obscures: the reality of state control. Combined with regulatory interventions restricting tariff choice, it is challenging to identify net benefits from retail competition. In the 2008 Probe, Ofgem estimated the cost of competition as £730 million. If these costs were unchanged in real terms, the 21 per cent rise in the RPI since 2007 implies that costs of competition are currently around £883 million a year, all of which could be eliminated.

- **Lower regulated supply margin.** In 2012, Ofgem estimated that the Big Six had an average profit margin of 4.3 per cent in the domestic supply market.[83] This is considerably higher than the 0.5 per cent margin the MMC recommended in 1995 for Scottish Hydro or the 1.5 per cent margin set by Offer and Ofgas in 1998 'to reflect the increased risks associated with the competitive environment'.[84] With domestic supply turnover of £15 billion a year, each percentage point of suppliers' profit margin costs consumers £150 million a year. Setting a regulated supply margin of one per cent would leave consumers £510 million a year better off.

- **Improved accountability and transparency.** In the absence of market disciplines in allocating capital between various generating technologies, relocating electricity generation from EMR's public/private sector twilight zone gives the Treasury greater incentives and ability to control and scrutinise costs and improves transparency and accountability to Parliament. Whilst it is difficult to identify

83 Ofgem (2013), *The revenues, costs and profits of the large energy companies in 2012,* p.i.

84 Ofgem (2008), *Energy Supply Probe – Initial Findings Report*, p. 102.

> cost reductions *ex ante*, it is hard to believe that the same choices would have been made (e.g. the push for extremely high-cost offshore wind capacity) if the cost implications were recognised in the public sector's accounts and subject to value for money scrutiny.

These cost savings, summarised in Table 7 below, amount to around £2.5 billion a year, rising to £3.5 billion after 2020.

Table 7: Identified cost reductions from nationalisation

	£million a year
Lower cost of capital	1,100 – 2,100
Elimination of costs of competition	883
One per cent supplier margin	510
Total	2,493 – 3,493

Source: Author's estimates.

The benefits of the lower cost of capital are shared 50:50 with non-domestic electricity customers but 100 per cent of the savings from eliminating the costs of competition and reduction in supplier margins accrue to domestic customers. With approximately 27 million domestic meters, this implies an annual £72 reduction in the average domestic electricity bill compared to EMR rising to £90 once all the £90 billion of new generating capacity becomes operational. To put these in perspective, the £125 million a year average saving identified by DECC in its justification for EMR implies a reduction of £2.31 a year off the average domestic electricity bill.

7.2 Cost savings from abandoning the renewables target

Cost savings from abandoning the renewables target arise from the avoided capital costs of 33GW of renewables and 5GW of conventional capacity plus onshore and offshore grid connections and reinforcement. Insofar as some of this has already been undertaken, the savings will be deferred until the end of the assets' economic lives. For consistency with the estimated cost savings from nationalisation and to be consistent with the analysis supporting the Coalition's 2011 EMR White Paper, the savings from abandoning the renewables target also assume an 10 per cent cost of capital for renewables, although this seems improbably low given the types of investor in renewables and the speed of wind capacity build-out.

Annual capital costs (cost of capital plus depreciation) of the 28GW of renewable capacity and the extra capital costs of 5GW of renewables in excess of the costs of CCGT capacity are set out in Table 8. It also includes annualised capital costs in respect of £8 billion of onshore and £15 billion of offshore grid extensions and reinforcements. Altogether, these total to £14,646 million a year.

Table 8: Annualised additional capital costs of renewables

	Assumption	Source	£million a year
28GW renewable generating capacity:	£68.6 billion capital cost based on 50:50 onshore/ offshore	Section 2.3 & Box 1	
Cost of capital	10% on replacement value	DECC/ CEPA	6,860

Depreciation	15-year asset life	Prof Gordon Hughes	4,573
Extra cost of 5GW renewable generating capacity over CCGT	£9.2 billion	Section 2.3 & Box 1	
Cost of capital	8% on replacement value		920
Faster depreciation of renewable assets	CCGT 25-year asset life	Prof Gordon Hughes	920
£8 billion of onshore grid connections & reinforcement			
Cost of capital	4.55%real plus 2% inflation	Ofgem (1)	262
Depreciation	45 year asset life	Ofgem (2)	178
£15 billion of offshore connections			
Cost of capital	8%	Author's estimate	600
Depreciation	45 year asset life	Author's estimate	333
Total			14,646

Source: Gordon Hughes email to author, 3 September 2014; Ofgem (2012), RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas, (1) Table 3.1; (2) Table 2.1.

As shown in Box 2, the variable fuel costs avoided in return for £14,646 million of annual capital costs of renewables at the 2013 gas price is £3,069 million a year. The difference of £11,577 million is the annual cost of renewables, a figure which is rising with the fall in natural gas prices. Split 50:50 between commercial and residential customers, this reduction is equivalent to an average £214 saving a year per residential customer. With coal prices nearly two thirds lower than natural gas, the reduction would be greater were the market free to choose the lowest cost fossil fuel.

Box 2: Cost of fuel alternative to 33GW of wind capacity

Based on an average wind load factor of 27.7 per cent (2009-2013),[1] 33GW of wind capacity would generate 80.1 TWh of electricity a year. What are the fuel costs of foregoing supposedly free wind energy? Modern CCGTs are highly efficient at converting the energy in gas to electrical energy, achieving efficiencies of 60 per cent or more.[1] Assuming 60 per cent efficiency, to generate the same output as the 33GW of wind capacity requires 133.5TWh of natural gas. In 2013, electricity generators paid an average price of 2.299p per kWh (£22.99 million per TWh) – the highest price for natural gas in 20 years (in 2000, the average gas price was 0.595p per kWh).[1] At this price, the gas bill to generate 80.1TWh of electricity is £3,069 million.

7.3 Enhancing competition and protecting consumers

Intermittent renewables subsidised by levies on consumers have destroyed the effective functioning of the market for electricity. It therefore follows that the path to an effective market requires removing those subsidies and, as far as possible, ensuring renewables bear the system-wide costs and risks they give rise to.

Steps which would accelerate the return to market pricing include:

- Removing all price supports and other incentives in respect of planned renewable projects (similarly for nuclear);
- Deploying all legal means to remove price supports or reduce their level as well as obligations to purchase electricity generated by renewables;
- Taking the extra infrastructure costs of grid extensions and reinforcements out of National Grid's Regulatory Asset Value and allocating them to the renewables asset which gave rise to them; and
- Applying international experience to the design of a revised and updated Pool through which all generators must make binding bids to sell their output.

There are two benefits to reviving the Pool:

- A reinvigorated Pool would reduce barriers to entry in generating and weaken the market power of the Big Six; and
- By providing symmetrical right/obligation to sell at the Pool bid price, renewables operators would have to do deals with conventional generators, thereby internalising the intermittency costs of renewables and obviating the stated rationale for a DECC-run Capacity Market.

7.4 Institutional factors in choosing between the state and the market

We know British governments can create a successful electricity market. The benefits of the market were demonstrated in the first decade of privatisation. They include:

- Substantial investment in modern CCGT generating capacity with investors, not customers, taking risk;

- Not investing in high-cost nuclear capacity or the Central Electricity Generating Board's (CEGB) favoured new generation of big, coal-fired power stations;

- Lower prices following the breaking of the generating duopoly after the regulator acted to encourage new entrants; and

- Large gains in labour productivity.

By contrast, adoption of the renewables target has seen the market replaced by government control. This inevitably raises the question of whether DECC is up to the job. Two data points help provide an answer. The first is the rollout of smart metering, demonstrating both DECC's agenda-driven approach to cost-benefit analysis and poor cost control (Box 3).

Box 3: DECC's rollout of smart metering

The theory behind smart meters is to provide more accurate billing information that is and cheaper to collect for suppliers and to enable consumers to adjust their consumption in response to fluctuations in electricity prices through the day.

The EU has passed a Directive that requires Member States, *provided they are economic*, to introduce smart meters for electricity in a minimum of 80 per cent of homes by 2020 but require the installation of smart meters to be prefaced by a cost-benefit analysis. A 2007 impact assessment by consultants Mott MacDonald showed a net disbenefit of £4.5 billion, which by 2011 had been transformed by DECC into a net benefit of £4.9 billion. With the help of this £10.5 billion swing in the benefit appraisal, the UK has set itself more ambitious targets, aimed at equipping all suitable houses with smart meters for electricity and gas by 2018. This would entail the installation of 53 million smart meters.

Over objections from the Cabinet Office and despite highly critical reports by the National Audit Office and Public Accounts Committee, DECC is pushing ahead with a universal rollout at a cost of £11.3 billion for 53 million meters – £220 per meter, or £440 for a household with electricity and gas – costing households £23 a year. By contrast, a July 2013 report for the German Ministry of Economics and Technology concluded that a mandated rollout to all German consumers was not economically beneficial and recommended segmenting the market so that smart meters would be installed for heavy users and in new and renovated properties (at a cost of €90 per installation) and upgraded meters for the rest (€40 per installation).

Meanwhile, in the eight years it took DECC to devise but not implement the most complex smart meter rollout in the world, the Italian utility company ENEL designed and has already installed meters in around 90 per cent of Italian households at a cost per meter of £65.

Source: Henney, A. (2013, unpublished); Thomas, S. (2012), "Not Too Smart an Innovation: Britain's Plans to Switch Consumers to Smart Electricity and Gas Meters", Energy & Environment, Vol. 23, Issue 6/7, pp. 1057-1074; Reuters (2013), "Europe to follow Italy's lead on smart meters', 30 May.

The second data point is DECC's outsourcing of EMR delivery to National Grid, a private sector company, because the department itself lacks the required expertise (Box 4).

Box 4: Outsourcing EMR delivery to National Grid

Although DECC is notionally responsible for overall policy and policy costs of EMR, under the Energy Act, the role of EMR delivery body is outsourced to National Grid as the System Operator. In this role, National Grid is to:

- Administer the allocation of CfDs and run capacity auctions for the Capacity Market; and
- Provide evidence and analysis to inform the Government's decisions on policy parameters such as CfD strike prices.

DECC concedes that conferring the EMR delivery role on National Grid could create conflicts of interest and takes these concerns 'very seriously,' pledging that 'the Government fully intends to take whatever steps prove necessary to mitigate any conflicts of interest.' Ofgem will scrutinise National Grid's costs to ensure they provide value for money, which could include setting 'financial and reputational incentives.' Thus the demarcation between public and private sectors has become so blurred that a private sector company is discharging a public policy function the public sector can't do, itself funded from higher electricity bills.

Source: DECC (2012), Electricity Market Reform: Policy Overview, Annex C, p.6, p.10 & p.17.

7.5 Is there a policy rationale for renewables?

In principle, the renewables target is separable from the UK meeting its international decarbonisation commitments. According to David Newbery, the logic of the renewables directive 'is not to reduce the EU's CO_2 emissions, whose level is already determined by the ETS cap.' Member states' internal politics played an important role in formulating the EU position. According to a leaked DTI paper prepared after the Spring 2007 EU Council,

> 'Germany are strong proponents of the renewables target, i) given the sensitivity of nuclear in coalition politics, ii) a strong and growing renewables industry and iii) because Merkel personally championed it at the Spring [2007] Council.'[85]

Industrial policy was an additional rationale mentioned in the DTI paper – boosting the competitiveness of the European renewables industry. A 2014 study by the European Commission found that in 2012, the EU ran a €2.45 billion surplus in wind components, a level of performance that had been consistent since 2008. However, the EU ran a €12 billion trade deficit in solar energy components, which in 2010 had been €21 billion.[86] As industrial policy, the renewables target is a costly failure.

Instead, Newbery suggests the renewables target can be understood as a demand-pull instrument to encourage investment in renewable energy which is expected to lower the cost of future roll-out through learning-by-doing and induced innovation. Newbery characterises the case for EU action that, if successful, will encourage other countries to adopt these technologies when their costs fall sufficiently, thereby mitigating CO_2 emissions with universal benefit.[87]

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85 Accessed via Ashley Seager & Mark Milner, Revealed: cover-up plan on energy target, theguardian.com (13 August 2007).

86 European Commission (2014), *Energy Economic Developments in Europe: Part III Renewables: Energy and Equipment Trade Developments in the EU*, p.111.

87 Newbery, D. (2012), 'Reforming Competitive Electricity Markets to Meet Environmental Targets,' *Economics of Energy & Environmental Policy,* Vol 1, No 1, p.78.

Thus the EU renewables target can be viewed as a huge proof-of-concept exercise. The EU is incurring costs so that, if the experiment is successful, the learning experience can be made freely available to the rest of the world. Indeed, the 2009 directive implicitly recognises the onerous nature of renewables, as richer nations have higher targets than poorer ones. Consequently it is more advantageous to be a follower than a renewables pioneer:

- Followers do not incur learning costs;
- It leaves the pioneers to uncover the first mover mistakes; and
- If renewables prove costly to integrate, those costs can be totally avoided by sticking with conventional technologies.

Essentially, the choice is between renewables and the market. Choosing the market would require the UK to renegotiate its commitment to generate 15 per cent of its total energy from renewables under the EU's 20-20-20 Renewables Directive (2009/28/EC). The logic of this leads to the conclusion that the UK would be better off negotiating a permanent opt-out from the Renewables Directive and any successor, freeing itself to rediscover the benefits of a proper market in electricity.

Abandoning the renewables target and implementing the steps outlined in Section 7.3 would, over time:

- avoid the escalating costs and additional system disruption of putting more renewable capacity on the grid ('when in a hole ...');
- cut household electricity bills;
- improve business competitiveness;

- raise the electricity industry's capital and labour productivity;
- boost Britain's economic performance.

It would act like a broadly based tax cut, helping the least well off the most in terms of their monthly budget, without costing the Exchequer a penny and increasing the deficit.

8. A DESCENT INTO POLICY INCOHERENCE

In October 2012, soon after becoming Energy and Climate Change Secretary, Ed Davey told the Confederation of British Industry (CBI):

> 'Let's start by admitting that the current arrangements - phase zero, you might say - are actually quite dirigiste … There's a good case for that statist approach now.'[88]

Less than two years later, Mr Davey had a very different message. Boasting how he'd asked the competition authorities to do an assessment of the energy markets, Mr Davey told the CBI:

> 'Tackling these issues through independent competition authorities, rather than through ill-thought through electoral gimmicks like state-regulated price freezes, is a far better way to provide companies and investors with the confidence that future market reforms will be

[88] Davey, E. (2012), Speech at CBI breakfast, 18 October.

evidence-based, fair and just, and free from political interference.'[89]

These contrasting statements illustrate the policy incoherence of EMR. You cannot be dirigiste and pro-competition at the same time. You cannot have a statist approach and go on to claim that manipulating the energy market is 'absolutely unacceptable.'[90] Threatening to jail energy executives, as reported by the BBC, also illustrates the risky role of the private sector under EMR – to supply high-cost capital because the Government is unwilling to provide the capital itself and be set up as lightning conductors for public anger at rising energy prices caused by Government policies.

What of energy policy being 'evidence-based, fair and just'? Assessed against the Government's three objectives for energy policy, renewables policy is not remotely rational, fair of affordable:

- **Keeping the lights on.** Weather-dependent renewables are inherently poor at reliably generating electricity to meet demand. Indeed, the Government has acknowledged the 'significant challenge' represented by 'operational security (i.e. enough responsiveness to ensure real-time balancing of supply and demand)', though DECC couldn't bring itself to name the culprit.[91]

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89 Davey, E, (2014), Speech to the CBI Energy Conference 2014, 17 July.

90 BBC News (2014), "Energy price riggers to face jail under new proposals", 6 August.

91 DECC (2012), *Electricity Market Reform: Policy Overview*, Annex C, p.4.

- **Keeping energy bills affordable.** Self-evidently, setting strike prices for renewables (and nuclear) that are double the current wholesale price of electricity puts upward pressure on energy bills – and that's before taking account of the higher system grid level costs of renewables which the Government tends to ignore (Figure 3). If affordability really were a driver, nationalisation would provide a lower cost renewables route.

- **Decarbonising energy generation.** A 2014 Brookings analysis quantified the avoided carbon emissions per MW from wind displacing baseload coal generation at $106,697 a year and $69,502 a year for solar, based on a value of at $50 per tonne of carbon. By contrast, CCGT-generated electricity saves $416,534 of carbon per MW a year – nearly four times that for wind and six times that of solar in the US, where solar capacity factors are nearly double those in the UK.[92]

Overall, the Brookings analysis, which does not explicitly incorporate the extra grid infrastructure costs of renewables, found that wind and solar generated respectively annual net disbenefits of $25,333 and $188,820 per MW at a carbon price of $50 a tonne whereas CCGTs generated an annual net benefit of $535,382 per MW.[93] The conclusion is inescapable: ditching renewables and encouraging shale fracking is better economics and more effective at reducing carbon dioxide emissions.

Despite all the energy white papers, official analyses and the Government conceding that renewables are on course to cost

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92 Frank, C (2014), *The Net Benefits of Low and No-Carbon Electricity Technologies: Brookings,* Table 9A & p.17.

93 Ibid. Table 9A.

£48.3 billion (before extra grid and dispatchable capacity costs), the Government has yet to produce a document analysing the costs and benefits of intermittent renewables to justify its leap into the dark. Delay in changing course merely adds to wasteful spending on renewables capacity for which the Government has no objective policy case. Deciding to opt out of the EU's renewables target would take Britain off the escalator of higher energy bills and enable electricity supply and demand to be determined by the market, not central planners in Whitehall.

9. A LESSON FROM THOMAS EDISON

At 3pm on 3 September 1882, Thomas Edison switched on the first incandescent bulbs powered by his Pearl Street generator several blocks away. It was a huge technical accomplishment. In Edison's words:

> 'It was not only necessary that the lamps should give light and the dynamos generate current, but the lamps must be adapted to the current of the dynamos, and the dynamos must be constructed to give the character of the current required by the lamps, and likewise all parts of the system must be constructed with reference to all other parts, since, in one sense, all the parts form one machine, and the connections between the parts being electrical instead of mechanical.'[94]

Edison's brilliance was not solely that of an inventor. He was an entrepreneur who changed the world. According to the economic historian Thomas Hughes, from the start, Edison realised his

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94 Thomas P Hughes (1983), *Networks of Power: Electrification in Western Society 1880 – 1930* (The Johns Hopkins University Press, 1983), p.22

system would have to be economically competitive. Thus he conceived of the problem to be solved by invention as inseparably technical and economic. Every technical step was informed by the need to beat the economics of gaslight. An example of Edison's understanding of the integrated nature of electrical production, transmission and consumption is opting for high resistance filament light bulbs, otherwise the current required such large copper wires for mains distribution as to make it uncommercial.

When politicians decided to impose renewables on the electricity system, they took the opposite approach to Edison. Renewables didn't have to be cost competitive. They didn't have to be reliable. The extra costs they impose on the system were ignored. Politicians did not want to think about the wholly predictable destruction of the electricity market from their policies. The world would have to fit around their preferred generating technology.

Edison's approach ushered in the age of electricity. If central planning worked, the Berlin Wall would still be standing.

ANNEX I ***Big Six: Electricity Supply Cost Structure*** *(cont. on following pages)*

Year to 31 Dec 2013

£m	**Centrica**			**E.ON**			**EDF**		
	Domestic	*Non-domestic*	*Total*	*Domestic*	*Non-domestic*	*Total*	*Domestic*	*Non-domestic*	*Total*
Revenue	**3,497**	**1,951**	**5,448**	**2,573**	**2,883**	**5,456**	**2,013**	**3,506**	**5,519**
Fuel costs	1,554	1,010	2,564	1,125	1,735	2,860	906	2,114	3,020
Network costs	903	442	1,345	610	638	1,248	502	738	1,240
Environmental & social obligations	479	211	690	328	358	686	264	433	697
Other direct costs	-	28	28	4	1	5	2	17	19
Sub-total	2,936	1,691	4,627	2,067	2,732	4,799	1,674	3,302	4,976
Indirect costs	505	206	711	321	76	397	340	156	496
D&A	28	5	33	6	1	7	22	8	30
Sub-total	533	211	744	327	77	404	362	164	526
Total costs	**3,469**	**1,902**	**5,371**	**2,394**	**2,809**	**5203**	**2036**	**3466**	**5502**
Ebit	**28**	**49**	**77**	**179**	**74**	**253**	**-23**	**40**	**17**
Ebit margin	*0.8%*	*2.5%*	*1.4%*	*7.0%*	*2.6%*	*4.6%*	*-1.1%*	*1.1%*	*0.3%*
Mark-up on indirect costs	*5.3%*	*23.2%*	*10.3%*	*54.7%*	*96.1%*	*62.6%*	*-6.4%*	*24.4%*	*3.2%*

Big Six: Electricity Supply Cost Structure *(Cont.)*

Year to 31 Dec 2013

£m	**RWE**			**ScottishPower**			**SSE (Year to 31 Mar 2014)**		
	Domestic	*Non-domestic*	*Total*	*Domestic*	*Non-domestic*	*Total*	*Domestic*	*Non-domestic*	*Total*
Revenue	**2,091**	**3,180**	**5,271**	**1,804**	**888**	**2,692**	**2,697**	**2,387**	**5,084**
Fuel costs	892	1,864	2,756	795	490	1,285	1,269	1,457	2,726
Network costs	483	687	1,170	454	221	675	694	534	1,228
Environmental & social obligations	278	419	697	238	105	342	362	297	659
Other direct costs	-	-	-	-	-	-	-	30	30
Sub-total	1,653	2,970	4,623	1,487	816	2,303	2,325	2,318	4,643
Indirect costs	298	113	411	176	45	221	277	47	324
D&A	30	7	37	3	0	3	3	-	3
Sub-total	328	120	448	178	45	224	280	47	327
Total costs	**1,981**	**3,090**	**5,071**	**1,666**	**861**	**2,527**	**2,605**	**2,365**	**4,970**
Ebit	**110**	**90**	**200**	**139**	**27**	**165**	**92**	**22**	**114**
Ebit margin	*5.3%*	*2.8%*	*3.8%*	*7.7%*	*3.0%*	*6.1%*	*3.4%*	*0.9%*	*2.2%*
Mark-up on indirect costs	*33.5%*	*75.0%*	*44.6%*	*77.7%*	*58.6%*	*73.9%*	*32.9%*	*46.8%*	*34.9%*

Big Six: Electricity Supply Cost Structure *(Cont.)*

£m	**Aggregate Big Six**		
	£m	*% of revenue*	*% of costs*
Revenue	**29,470**	**100.0%**	
Fuel costs	15,212	51.6%	53.1%
Network costs	6,906	23.4%	24.1%
Environmental & social obligations	3,771	12.8%	13.2%
Other direct costs	82	0.3%	0.3%
Sub-total	25,971	88.1%	90.7%
Indirect costs	2,560	8.7%	8.9%
D&A	113	0.4%	0.4%
Sub-total	2,673	9.1%	9.3%
Total costs	**28,644**	**97.2%**	**100.0%**
Ebit	**826**	**2.8%**	
Ebit margin	*2.8%*		
Mark-up on indirect costs	*30.9%*		

Source: Ofgem (August 2014), Energy companies' Consolidated Segmental Statements for 2013

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