

Towards a bright future

Transforming
the electricity market

“green
alliance...”



**Towards a bright future:
transforming the electricity market**

Edited and compiled by Rachel Cary

This report is a collection of essays on electricity market reform by leading experts. They offer valuable contributions to the general debate and comment on certain specific aspects of electricity market reform, but the collection does not attempt to represent all views. The views expressed in this publication remain those of the individual authors alone, and do not necessarily reflect the views of Green Alliance or their partners.

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Green Alliance

Green Alliance is an influential, independent organisation working to bring environmental priorities into the political mainstream. We work collaboratively with the three main parties, government, the third sector, business and others to ensure that political leaders deliver ambitious solutions to global environmental issues.

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Contents

Foreword Matthew Spencer	4
The case for reform and the challenges ahead Rachel Cary	5
The History of Wholesale Electricity Market Design in Great Britain Professor Stephen Thomas	10
What has retail competition achieved? Dr Nick Eyre	14
Price, quantity and the ‘middle ground’ in electricity market reform Tim Tutton	19
Seizing the opportunity: setting us on a path to a low carbon electricity system Simon Skillings	24
Does an Emissions Performance Standard have a role? Professor Jim Skea	28
Running a low carbon electricity system efficiently Phil Baker	32

Contributor biographies



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Foreword

Matthew Spencer, director, Green Alliance

At the heart of the energy market debate is the certainty paradox. This means that to secure investment certainty it is often necessary to go through a period of change and investor uncertainty. The fear of change should not inhibit us from making the decisions needed to create a sustainable and low carbon electricity system. For too long we have made incremental changes to the electricity system, resulting in one that is very complex and structurally weakened by regulatory risk to investors.

Our current electricity system has been good at sweating existing assets but poor at incentivising investment in new high capital cost generation. It cannot provide the certainty that investors need to make long-term investments in low carbon outcomes. Tweaking the system will not do the job. More ambitious reform is required to guarantee the timely delivery of a decarbonised electricity system. In addition, if government does not reduce the risk faced by investors the cost of the transition to a low carbon electricity system will be higher than it needs to be, increasing the burden on consumers.

We now have the opportunity to channel the reforming instincts of the Coalition Government to modernise our energy system, to drive new low carbon investment and to reduce demand for electricity¹. Energy market design may be fiendishly complex but ultimately it defines where we are going and what we care about. The contributions in this report reinforce the case for bold reform and identify how government might redesign the electricity market, and the policies that shape it, to work in our long-term interests.

1. The case for reform and the challenges ahead

Rachel Cary, senior policy adviser, Green Alliance



The government is currently in the process of assessing the need for reform of Great Britain's electricity market and the wider policy framework that shapes it, and is due to release a major consultation in autumn 2010. The aim is to ensure the market design is right for a successful transition to a low carbon economy: an opportunity that should not be missed.

The consultation comes after months of discussion about whether the current system is fit for purpose post-2020. Commentators from across the energy sector have suggested that whilst the current arrangements may have served us fairly well over the past decade, they are far from adequate to deliver the low carbon electricity system we urgently need to develop.

The pressure for reform started to grow in October 2009 when the Committee on Climate Change raised concern in its first progress report over the ability of the current electricity market to deliver the high volumes of investment in low carbon generation required to meet our carbon targets. Their analysis showed the need for a very different electricity sector in the 2020s where the only role for new unabated fossil plant will be to meet peak demand. This was followed by Ofgem's Project Discovery in February 2010 which questioned the ability of the current arrangements to deliver a low carbon and secure electricity system at a reasonable cost to the end user.

The case for reform

Many have pointed to the need for the rapid decarbonisation of the electricity sector by 2030 both to achieve direct emissions reductions from power generation, and to enable the decarbonisation of the heat and transport sectors through electrification. Early decarbonisation of the electricity sector is seen as central to meeting our 2050 greenhouse targets, and is a cost-effective way to meet the target.

Relying on the current arrangements to deliver a low carbon electricity system is highly risky. It is far from clear whether they will deliver the right type or the right volume of investment. Even if the

current arrangements do deliver the large volumes of investment required, the costs will be significantly higher due to the high risks currently faced by investors in low carbon technology.

The current market structure favours low capital cost power plants, and has many features that make low carbon investment unattractive or more expensive than necessary. The result is that most of the new electricity generation plants built under current arrangements have been gas fired. Uncertainty over whether developers will have customers for the waste heat produced from electricity generation has meant that most have been built as Combined Cycle Gas Turbines (CCGT) rather than as Combined Heat and Power (CHP) plants (which are more efficient and therefore lower carbon). Investment in renewables has been slow and the policy mechanism chosen to support large scale renewables, the Renewables Obligation (RO), has been expensive².

Redirecting investment so that it goes into low carbon supply and demand reduction and response will be essential. The current arrangements are unlikely to deliver the massive leap in quantity of low carbon generation needed, or achieve the high level of coordination necessary in the tight timescales involved. There are also insufficient incentives for end users to reduce their electricity use and make it more flexible, both of which will be required to minimise the cost of a transition to a low carbon economy and enable us to meet our reduction targets.

Investment levels need to increase to around three times the current levels. The size of the investments required is also an issue. Carbon Capture and Storage (CCS), nuclear and offshore wind are all expected to play a major role in our future electricity supply. All of these technologies require large chunks of capital that are over the capital limit of most companies, and deployment needs to be at a scale and rate of build beyond what can be delivered by the existing energy companies alone. New models

to share risk and pool capital will increasingly need to be deployed to get these large infrastructure projects under way.

To achieve the high levels of investment in low carbon generation required, it will be important to attract new types of investors and simplify the complex policy framework. All this needs to take place against a backdrop of low appetite for risk in the financial markets. This will be challenging given that many low carbon investments involve new or unfamiliar technology that is considered risky. Uncertainty over future electricity demand and price also significantly increases investor risk.

Maintaining security of supply and running the electricity system efficiently as we move to a low carbon system will become increasingly difficult under the current arrangements. The mechanism that provided a security safety net was removed during the last reform of the electricity markets and the wholesale price fails to provide a sufficient long term price signal to stimulate investment. Electricity prices will become increasingly volatile as the level of wind generation increases, which could have a negative impact on the incentives to invest in flexible back-up fossil fuel power stations.

The short term price signal in the current wholesale market will become increasingly inadequate at providing information on how best to run the system efficiently. There are a number of design features of the current system that penalise low carbon generation, such as the way in which supply and demand are balanced. As Phil Baker outlines in chapter seven, the rules under which the system operates will become increasingly unfit for purpose as the amount of low carbon generation increases.

What are the dilemmas/trade-offs?

Volume versus price? The various options discussed in both Project Discovery and the previous government's Energy Market Assessment (EMA) range from small tweaks to the current system to a radical breakup of the existing markets and a move to a model where a single agency procures all electricity. In chapter

four, Tim Tutton suggests that options where the volume of generation is set and the market determines its price may be more efficient than those where the price is set and the market delivers the volume. Greater certainty over volume may be required as the risks of under delivery are too great; we cannot risk security of supply or failing to meet our greenhouse gas targets.

Timing and resources. One of the major quandaries thrown up by the debate is whether to go straight for an enduring solution that will suit the medium to long term or whether we should pursue temporary fixes that are less disruptive. Some of the more radical options for reform may require significant resources to implement, both within government and across the energy sector. However we should not stick to the current model for fear of disruption if it will definitely not deliver the wider societal outcomes of electricity security and decarbonisation. Some commentators suggest that the costs associated with radical reform will be significantly offset by the resulting reduced cost of capital. In addition there are a number of ways to reduce the pain of any transition and prevent a major hiatus in investment.

Flexibility versus certainty. A careful balance will need to be achieved between designing a system or policy which is sufficiently responsive to unforeseen changes, such as major technology developments, and one which preserves investor certainty. A greater level of prescription increases the risk of getting it wrong but it reduces uncertainty and therefore investment costs.

Who is best placed to take risk? The right market design will place risk on those best able to handle it. The current arrangements place risk on private energy companies however commercial risk does not go away if it is borne by shareholders; consumers/taxpayers always end up paying through a higher cost of capital. Future electricity demand is highly dependent on government policy and it is hard to predict future demand and invest accordingly. Government may be better placed to take on

some of the volume risk arising from its policies. It will however be important to apply competition to the parts of the process where developers are best able to handle risk, ie construction and operation.

System efficiency versus reducing investment risk. Many investors may want mechanisms that reduce their exposure to electricity price risk and are simpler to understand, for example a standard feed-in tariff (FIT) rather than a premium FIT³. However to run the system efficiently you may want to expose generators to system price signals so they operate their electricity generators in a way that helps the overall system. Given the need for lots of investment now, the short term focus might need to be on attracting investment, and we may want to optimise the operation of the system later. In addition, there is no point in exposing certain operators to price risk if they cannot respond to it; many low carbon electricity generators have limited control over the time and amount of electricity they generate. The degree to which actors are exposed to price signals also has implications for the demand side. This will be an important consideration when considering the use of quantity instruments which could dampen price signals in the electricity markets and reduce the amount of demand response. If we decide to continue to rely on price signals alone we may need to change the electricity trading and retail arrangements to make prices more transparent and cost reflective.

What are the critical success factors?

For a successful and affordable decarbonisation of the electricity sector in the timescales required we need to:

1. Consider ambitious reform. Options that involve a tweaking of the current system will not deliver the necessary volume of low carbon and back-up generation, nor keep existing peaking plant on the system; market signals may not work and unplanned volume will be very expensive. If we stick with the status quo there will be a need for greater regulation and we

could end up with an even more complicated framework; this will not be attractive to investors. A carbon floor price alone will be insufficient. Carbon price risk is only one of a number of risks faced by developers; swings in gas price have been significantly higher than those in the carbon price.

2. Learn from past mistakes. We need to learn from previous reforms to the electricity market as discussed by Stephen Thomas in chapter two, and not be afraid to revisit options that may have failed in the past. New entrants are required to deliver innovative new services and provide additional sources of finance. Community level ownership also needs to increase to overcome the massive planning barriers that currently exist and enable end users to benefit from the transition to a low carbon electricity system. However new entrants face considerable barriers to entry, one of which is the lack of liquidity and transparency in the market. This and other barriers will need to be addressed if we are to bring in new entrants.

3. Reduce the cost of low carbon investment. Any reform needs to address the fundamental problems associated with low carbon investment so that the cost of capital is reduced. As Simon Skillings discusses in chapter five, government can reduce investor uncertainty by specifying what it actually wants and by taking some risk, for example on future electricity volume, away from the market. In addition, an independent Green Investment Bank (GIB) would be highly desirable to leverage private sector investment at the scale that is required.

4. Prepare for EU integration. Integration with European electricity markets will be vital to ensure that the costs of the transition to a low carbon economy are minimised and the United Kingdom exploits the economic opportunity associated with its low carbon resources. We therefore need to ensure that our electricity market design is compatible with integration into a wider European electricity market and make strategic decisions about the way we develop our electricity networks.

5. Promote demand side measures. It will be vital to ensure any arrangements promote demand side measures that could be used now and in the future (eg domestic time of use tariffs). Any quantity instrument or contracting process should recognise and promote energy efficiency and demand response projects, as well as those that supply electricity. As Nick Eyre outlines in chapter three, we must consider the role of the retail market as well as the wholesale market if we are ever to achieve the required level of reduction in electricity use for existing services.

6. Provide cost effective support for renewables and CCS. Technology specific support for renewables is required. It is simple for investors to understand and has been shown to effectively bring down the cost of renewables in other countries. The renewables obligation is increasing complex and is being made to behave increasingly like a FIT. Better options for large scale renewables are a premium feed-in tariff or some form of long-term contract. Simple, standard FITs may continue to be the best option for small scale renewables and government should consider raising the capacity threshold to enable greater community ownership. CCS will need targeted Government support in the short to medium term to demonstrate the technology, and some form of mechanism that facilitates deployment in the long-term.

7. Not provide public subsidy to new nuclear. Support for new nuclear is a highly political issue given the government's commitment to not provide public subsidy. However the definition of what constitutes a subsidy is under debate and is becoming increasingly ambiguous. The Secretary of State has recently suggested that nuclear should receive any benefits given to other low carbon generation through market reform. Options such as an extension of the renewables obligation to nuclear and CCS (the simplest form of a low carbon obligation) are considered by many to be a direct subsidy as it would give nuclear generators additional revenue above and beyond

that resulting from the wholesale electricity and carbon price. The RO was designed to give new technologies additional support, whereas nuclear is a mature technology that has already received billions of pounds over the last two decades. Anything that goes beyond correcting the lack of a carbon price would therefore constitute a form of direct subsidy. A low carbon obligation, linked to the carbon floor price, may conform to the new definition suggested by the Secretary of State but differentiating between carbon price correction and technology support will be challenging.

8. Ensure arrangements provide greater certainty over 2030 decarbonisation target. Promoting investment in low carbon electricity generation or technologies alone may not ensure a sufficient reduction in carbon emissions from the electricity sector. As Jim Skea discusses in chapter six, an emissions performance standard (EPS) could provide a useful back-stop. The adoption of a flexible 'bubble approach'⁴ is one possible solution. An EPS would however need to be designed carefully, include gas and be combined with sufficient incentives to ensure it promotes CCS and does not deter investment.

The following chapters make the case for reform and explore some of these issues further.

2. The History of Wholesale Electricity Market Design in Great Britain

Professor Steve Thomas
University of Greenwich

The reforms to British electricity in 1990 were made under the promise that an efficient wholesale electricity market could be created in which electricity generators would be forced to compete with each other 'every hour of every day'. The reforms targeted electricity generation as it represents the largest element of an electricity bill, typically comprising at least half the total price. The logic for reform was that competition would reduce the cost of generation and consumers would see real price benefits.

In an efficient wholesale market, the price of electricity must be set either directly through sales through a visible spot market or indirectly by providing a reference price that contract sales can be indexed to. It must also provide long-term price signals that will stimulate investment in new generation capacity and have at least six participants if it is not to fall into the category of 'concentrated' and uncompetitive.⁵ In the 20 years of its existence, the wholesale electricity market in Great Britain has never met any of these criteria.

The Power Pool: 1990-2001

The decision to privatise the electricity market was taken in 1987. Shares from the monopoly generator for England and Wales, the Central Electricity Generating Board (CEGB), were sold to private companies over the course of five years. Initially there were ambitious plans to create a 'double pool' with generators bidding against each other to sell their electricity in one pool and with wholesalers (and potentially users) bidding against each other to buy electricity in the other.⁶ This plan had to be abandoned because the development of the new design was too slow for the privatisation timetable. Since then, the wholesale market has never had a 'demand side' so it has always been half of a complete market.

The newly privatised system used an adapted version of the old software used by the CEGB. This software dispatched plants according to their marginal cost of generation so that the given electricity demand would be met as

cheaply as possible. In the new system, marginal generation cost was replaced by the price that different generators bid into the 'Pool'.

There were features in this software that might have made sense in a monopoly market but which would inevitably fail in the new competitive market. For example, there were capacity payments paid to all bidders, successful or not, that were meant to provide extra income to peak load plants that would be required for no more than a few hours per year, if at all, in order to maintain security of supply. The payment was determined by the gap between estimated demand and capacity built.⁷ This mechanism invited, and got, abuse by the generators who simply had to withdraw some capacity at key times to dramatically increase the amount they were paid for all the electricity they bid. There were however two even bigger problems:

- The post-privatisation generation structure was totally uncompetitive. The CEGB was split up into only three generation companies: Powergen, National Power and Nuclear Electric, which was the subsidised publicly-owned nuclear generator. Nuclear Electric was a price-taker, ie it had to bid below other generators to ensure it would run, because its plants were too inflexible to be able to risk unsuccessful bids. With only two bidders it would have been remarkable if the market had been competitive and it was not.
- The second issue was that while all generators had to place a successful bid to be dispatched into the Pool and retail suppliers had to buy from the Pool, they could sign bilateral hedging contracts (two way contracts for differences) that meant both parties were fully insulated from the Pool price. The Pool price was therefore of no interest to buyers and sellers for the vast majority of trades. Over the period 1990-97, less than 2 per cent of electricity supply was not covered by hedging contracts or price-taking nuclear electricity.

By 1997, a large volume of new generation projects entered the market. The owners of these so-called ‘merchant’ power plants thought they would be able to survive in the market without contracts by simply bidding into the wholesale market. A large gap in the market appeared to be opening: the Powergen/National Power hedging contracts were due to expire in 1998 and the nuclear volume was declining as old plants were retired and not replaced. It therefore seemed that, for the first time, the Pool would be guaranteed ‘liquidity’, ie there would be lots of real trading and there would be an opportunity to test the new competitive market to see whether it could actually work. For this to have happened however, the software would have had to have been updated and the capacity payment mechanism replaced by something less prone to abuse.

A particular advantage of the Pool was that it should, if working well, offer low barriers to entry for new entrants. Any new generation or retail company could easily enter the market. A new generator would know that, provided their electricity was priced competitively, it would be sold and a new retailer would know it would be able to buy its wholesale supplies at the same price as its competitors. Some argue that the advantages of a compulsory Pool are so strong that it was a serious mistake to abandon the Pool without ever testing it properly.⁸

New and better markets?

However, the decision was taken to introduce a completely different market design. This was initially called the New Electricity Trading Arrangements (NETA) and then British Electricity Transmission and Trading Arrangements (BETTA) when it was expanded in 2005 to include Scotland as well as England and Wales. The capacity payment mechanism was abandoned without replacement and participation in the market was no longer compulsory; generators could sign confidential bilateral contracts with retailers that completely bypassed the wholesale market. This left the visible market as a clearing mechanism for

generators with surplus electricity to sell to retailers needing to top up their supplies. The regulator who oversaw the design of the market assumed the liquidity of the market would be around 10 per cent. In practice, this has proved grossly optimistic and as before, the liquidity hovers around 2 per cent. The decision to allow generators to own retail businesses, known as vertical integration, in 1998 has meant that most electricity is bought and sold at prices that are only known to the generator and the retailer.

Once the government allowed vertical integration, it was clear that independent retailers would not survive long. Within three or so years, all 14 retail businesses in Great Britain were in the hands of just five generation companies. They were joined by the dominant gas company, British Gas, which bought generation capacity and sold electricity and gas as a package, making just six vertically integrated companies.

NETA was finally introduced in 2001 at a cost to consumers of about £760m.⁹ By then the Enron bubble had burst and the ‘merchant plants’ that could have supplied liquidity were being sold to integrated companies or abandoned. The visible wholesale price fell dramatically, by about 40 per cent, but to little or no benefit to consumers as none of this price reduction was passed on. By 2002, about 40 per cent of Britain’s generation capacity was owned by failed companies, and a consortium of banks that had lent money to merchant operators became the second largest generator in the UK with about 10GW of capacity (which equates to around a seventh of the total capacity of the UK electricity system).

The government and the regulator were too busy congratulating themselves on introducing a market design that had had such a strong influence on prices to ask hard questions about the source of the price reductions. There was little scrutiny given to the lack of benefits passed onto consumers, nor the fatal blow vertical integration dealt to merchant operators.

The government saved the bankrupt nuclear generator – privatised in 1996 – at a cost to taxpayers in excess of £10bn and took a controlling stake in the company as payment. The bankrupt fossil fuel power stations were mostly bought by the integrated generators at a low price. Électricité de France (EdF), one of the integrated companies, bought the last state-controlled nuclear generator in 2008. From 2004 onwards, the market in Great Britain has been increasingly dominated by integrated generator-retailers, with the few surviving merchant operators contracted long term to the integrated companies.

The barriers to entry for a new generator or retailer are now massive. Even if we assume that the integrated companies would not force new entrants out of the market through predatory pricing, who would a new generator sell its output to and who would a new retailer buy its supplies from? So while the Pool and NETA were apparently dramatically different in design, their effect was the same: 98 per cent of electricity was bought and sold at prices not related to the market and the barriers to entry were high.

Given that the vast majority of electricity is bought and sold at prices that are not known except by the two parties involved, the wholesale price lacks both credibility and transparency. When retail electricity prices increase as they have done in recent years – they have nearly doubled in the past six years – it is difficult for customers and the regulator to know how justified the price increases are.

Learning from the past

Before we go forward with yet another attempt to ‘fix’ the failed market, we need to make a judgement about whether the market is fixable or whether there is something fundamental about electricity that means it is not well suited to a free market design. We should not let our past experiences of pools and capacity mechanisms cloud our judgment of what may be appropriate going forward. The Pool was never given a proper chance and included a

badly designed capacity mechanism that was open to manipulation.

When considering options for market reform we must acknowledge problems that had been evident since 2002 and have arguably existed since 1990, and address them so that the barriers to new entrants can finally be reduced.

3.

What has retail competition achieved?

Nick Eyre

Retail markets provide the link between the energy industry and energy users. In delivering policy objectives to reduce energy demand they are potentially critical, particularly in the built environment where households and small businesses without energy expertise are the dominant energy users.

The explicit objective of retail energy market liberalisation in the last electricity market reform in 1998 was increased competition and therefore reduced prices. This provides a reduced incentive for energy efficiency, and it seems very likely that such an effect has indeed occurred. However, quantifying this with any accuracy is difficult, as it depends on two factors: the actual effect of liberalisation on prices and the price elasticity of energy efficiency, neither of which is straightforward.

One fear at the time of the last energy market reform was that liberalisation would lead inevitably to the death of regulatory driven programmes. This has proven entirely unfounded; regulated energy efficiency programmes have been a relative success story in the liberalised market. The programmes in Great Britain, the current Carbon Emission Reduction Commitment (CERT), have become comparable in scale to the largest in the world. However, it is difficult to claim that this is because of liberalisation, indeed, one might argue it is more in spite of it. Political willingness to regulate for energy efficiency coincided with full retail liberalisation and has been the critical factor. Liberalisation has not meant deregulation; regulation has continued and, as far as energy efficiency is concerned, increased.

The existing retail market is certainly not unproblematic, nor is it particularly popular. Economic efficiency gains from customer switching are now largely played out, with 'non-switchers' left on the higher incumbent tariffs now arguably bearing all of the costs and gaining less of the benefits of competition. The market is essentially an oligopoly of large, vertically integrated energy companies. This

structure is largely driven by the needs of retailers to hedge risk, and this acts as a barrier to market entry. The result offers little diversity to consumers. The emphasis on price competition delivered by a strong focus on cost reduction is not conducive to innovation in service delivery, certainly not in the building services required to secure a sustainable energy transition in the built environment. Past systemic changes, for example natural gas conversion would have been much more difficult to deliver within this market structure, and therefore there must be concerns about its appropriateness for future systemic change.

The challenges of the new agenda

The new context for UK energy policy is an increased emphasis on energy security due to the decline in indigenous oil and gas production, as well as more stringent and legally binding targets for carbon emissions reduction. Neither of these had the salience that they have now within the policymaking community at the time of the previous energy market reform. In particular, the objective of reducing UK greenhouse gas emissions by 80 per cent by 2050¹⁰ implies more radical changes to the energy system than were then contemplated.

Most policy attention has focussed on the need for 'close to zero carbon' electricity. However, this alone will be insufficient to meet our emissions reduction targets; significant reductions in energy use and decarbonisation of heat and transport, most likely by electrification, will also be required.

The implications for energy demand policy are very significant. Marginal improvements in energy efficiency through low cost measures will be insufficient. More substantial investments will be needed, for example, through 'deep retrofits' of buildings. Moreover, the predominant end use fuels – oil products in transport, gas in buildings and industry – will need to change. Some analyses point to wholesale electrification of transport and heating systems. Although these are certainly technically feasible by mid-century, they

potentially pose huge social, organisational and political problems. It therefore cannot simply be assumed that they will happen just because they appear to give the least cost solution to the low carbon problem. To the extent that full electrification is not achieved, the pressure to reduce energy demand will be further increased.

The extent of the challenge to deliver a secure low carbon energy system is becoming more apparent to policy makers. The types of change previously considered to be too challenging are now viewed with apparent equanimity and more ambitious changes are projected even within the current decade. The targets for renewable energy in 2020 are probably the best known case. But the plans for energy use in the home are equally challenging.

Policy will need to encourage a rapid transition in which energy demand is both reduced and, at least largely, electrified. Current policy for the household sector has some ambitious aims but is rather light on detail. There is a continuing, rather naive, faith that market based solutions will deliver. The emphasis for policy intervention is on financing through the Green Deal and information via smart meters. These are both important elements but certainly not sufficient for the transformation of demand on the scale and at the pace that is envisaged.

We will need a package of policy tools, including information and incentives in order to reduce energy use to the extent required. But the key lesson of the last decade is that regulation is likely to be a central element. Much of the emphasis needs to be on stronger regulation in the building sector, especially to drive low carbon refurbishment. But, given the scale of the challenge and the nature of the transformation required, it would be a mistake to neglect the role of the energy sector. The lesson of the last decade is that assuming such large scale delivery via a private energy services model is unwise; regulatory mechanisms will be needed.

There are demand side opportunities in wholesale market reform...

The recognition that energy supply systems must change is being accompanied by some reflection on the adequacy of the institutional and market structures to deliver the required levels of investment, connection and use of low/zero carbon electricity generation technologies required.

With Project Discovery, Ofgem surprised many in accepting that competitive wholesale markets alone may be unable to deliver the necessary investment and by actively canvassing more interventionist approaches. Similar changes can be seen in the attitude of the last government in the Energy Market Assessment¹¹ which has now been taken forward under the new coalition's Electricity Market Reform project.

The recognition that electricity markets face new challenges from high levels of inflexible and intermittent generation has led to increased interest in smart grids and demand side participation (DSP) in wholesale markets. New electricity loads can potentially exacerbate and/or mitigate the problem, depending on their temporal characteristics and associated storage capacity. In general, it is expected that electrification of transport may form part of the solution because the high storage capacity and low load factors of electric vehicles should allow off-peak charging. On the other hand, electrification of buildings is likely to exacerbate problems as heat demand is strongly correlated with existing peak electricity loads and buildings typically have passive heat storage of only a few hours.

DSP is at present effectively limited to large energy users who can participate directly in wholesale markets or for whom – more often in gas – interruptible contracts are commercially attractive. Greater engagement of the mass market of electricity users will require more sophisticated arrangements and more substantial changes in retail markets. Current market reform options assume that the improved prospects for time of day pricing, via

smart metering, point the way forward. They are certainly likely to offer some new options, although the lessons from energy efficiency in existing markets are that an uncritical assumption of 'rational' consumer behaviour is unwise.

...But ignoring the retail market is unwise

Conceptualising the role of energy demand in energy market reform as being restricted to temporal load switching is flawed. Much of energy demand will remain – in wholesale electricity market discourse – non-dispatchable. But that does not mean it is fixed on longer timescales. Load shifting is only a minor part of the changes required; investment to reduce demand and shift it away from fossil fuels is a more important, and difficult, goal for energy market policy.

In contrast to wholesale markets, there has been little attention to the role of retail market structure in the delivery of energy security and climate change goals. Both Project Discovery and the Energy Market Assessment focus on potential changes to the wholesale market. The barriers to entry in the retail market and their links to vertical integration are noted and considered problematic for effective competition, but not for broader goals. Presumably it has been assumed that such problems are best addressed from above and that retail markets can have little impact upon them. If so, given the major changes required in energy use, this seems likely to be a serious misconception.

Most of the proposals from the Energy Market Assessment will have limited impact on energy efficiency markets. None foresees anything but the continuation of a competitive retail model. Most of the options canvassed leave retail markets largely unaffected. Only the 'single agency buyer model' seems to offer a significantly different environment for retailers by re-establishing a transparent wholesale market price for electricity. This should address some of the barriers to entry in the retail market by removing the competitive advantage of

vertical integration. Whatever the upstream implications, it seems the option most likely to promote innovation in retail electricity markets. Interestingly, in this context, it was excluded from further consideration by the Energy Markets Assessment.

Regulatory requirements on energy suppliers have been successful in delivering low cost measures through CERT. However, the business model of the dominant energy suppliers, largely driven by the existing retail market structure, makes them high turnover, low capital businesses with very limited engagement with physical infrastructure. This makes them unlikely candidates to be the driving force for high cost, site specific, construction projects needed in the required demand side transition. It is therefore unlikely that simply ramping up existing regulatory obligations will be an adequate strategy.

Market reform needs to allow the emergence of new actors with the capacity to take on the low carbon transition agenda. These will need to be closer to final energy users and focus on new energy services in buildings, not cost effective purchasing in wholesale markets. This tends to point to a greater emphasis on the role of distribution companies and new actors in energy supply.

Policy post liberalisation has tended to downplay an active role for distribution companies, but this needs to change. The case is most obvious for smart grids, but, in the context of radical energy efficiency improvement and electrification of heat and transport, the role of distribution companies in financing investment on the customer side of the meter is also in need of re-examination.

The current strategy seems to be just to wait to see how the retail market reacts to the outcome of wholesale market reform. But perhaps we also need to think about active reform of the retail market. If we would like energy suppliers to engage more actively with their customers' energy use, then the structure of the retail

market should be designed to achieve that. Competitive retail markets were established to deal with the perceived challenges of the 1990s: to cut costs and instil financial discipline. No-one would invent the existing retail market structure to deal with the problems we now face, with a need for major demand side investment, supply/demand interaction, citizen engagement and systemic change. Other countries do not feel impelled to adopt market structures that promote high churn, low customer loyalty, high rates of customer dissatisfaction and disengagement from the technical changes now needed. Different market structure options – local authority ownership, consumer co-operatives and private sector franchises – are perfectly possible. Achieving any of them may not be easy, but we should at least debate how to move forward, rather than assuming the current retail market is fixed in perpetuity.

4. Price, quantity and the ‘middle ground’ in electricity market reform

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(The views expressed in this article are those of the author)



The current interest in electricity market reform stems, in the main, from one concern: the concern that the market, left as it is, will not produce the desired volumes of generating capacity or demand response. More specifically, the worry is not just that the market will not produce the desired volume of MW per se but also that the market will not produce enough of particular types of generating capacity, whether that means ‘flexible’ generation (to allow the electricity system to function in the context of higher volumes of inflexible or intermittent low carbon generation) or low carbon generation (to meet government climate change objectives). Affordability co-exists with security of supply and decarbonisation in the trio of objectives for the electricity sector, but the affordability in question is the affordability of delivering the generation capacity volumes or demand-side response to deliver the other two objectives.

This point can be illustrated with reference to the various options for market reform produced by both Ofgem (Project Discovery) and by

HM Treasury/DECC (Energy Market Assessment, hereafter ‘EMA’). These are shown below.

For both Project Discovery and the EMA, the options are, in effect, ordered (from left to right) by the extent to which they give assurance that volumes of particular types of generating capacity will be delivered, with least assurance being offered on the left hand side and greatest on the right.

The combined implication of the Ofgem and Treasury documents is that the extremes of the diagrams would not deliver on the government’s objectives. The EMA concluded that greater price certainty alone would not result in sufficient low carbon electricity post-2020 and that the single buyer option would “lose the benefits of a market-based approach to energy policy in terms of driving efficiency, so would be expected to offer a worse deal for consumers.”¹² In other words, the left hand side would be unlikely to produce the desired volumes of low carbon generation and the right hand side would be too

The Project Discovery options

Source: Ofgem (2010), ‘Project Discovery – Options for delivering secure and sustainable energy supplies’, February.

A Targeted reforms	B Enhanced obligations (EO)	C EO & renewables tenders	D Capacity tenders	E Central energy buyer
Minimum carbon price				Central buyer of energy (including capacity)
Improved ability for demand side to respond				
Improved price signals				
	Enhanced obligations on suppliers and system operator			
	Centralised renewables market			
		Replace RO with renewables tenders	Tenders for all capacity	

expensive, not least because a central, and possibly not-for-profit, agency would be taking decisions which would otherwise be the responsibility of profit-driven and decentralised market participants.

In addition – and this is more explicitly recognised in Ofgem’s analysis than in the EMA – the problem is not just about encouraging the build of low carbon plant. To the extent that government policy is successful in encouraging the build of low carbon plant, this plant will, at least for the foreseeable future, tend to be intermittent and/or inflexible, increasing the need for flexible plant which will often operate at low levels of utilisation.

An ‘energy-only’ market, like the one in Great Britain, explicitly pays for energy supplied and not for available capacity. If an ‘energy-only’ market becomes increasingly dominated by low marginal cost, low carbon generation, investment in flexible and back-up generation becomes increasingly unattractive. This is partly about the so-called ‘missing money’ problem

which is said to characterise all energy-only markets. This results from the tendency of the system operator and/or the regulator to act in ways which stop energy prices rising to sufficiently high levels at times of peak demand. This, by itself, makes it hard for peaking plant to be adequately remunerated through energy revenue alone. But it is also about the prospective loss of opportunities for new gas-fired power stations to run at base load. Over the past two decades, new gas-fired plant has been able to look forward to some years of base load running before being bumped down the implicit ‘merit order’ of plant by newer, more efficient plant. In current conditions the distinction between energy-only markets and ones which pay explicitly for making capacity available is relatively trivial. However this distinction grows in a future world in which gas-fired plant would have to run at low levels of utilisation from commissioning and would be more exposed to the problems of getting high prices during the relatively few hours of peak time running.

The Energy Market Assessment options

Source: HM Treasury/Department of Energy & Climate Change (2010), ‘Energy Market Assessment’, March.

A Greater carbon price certainty alone	B Support low carbon in the current market	C Regulate to limit high carbon generation	D Separate low carbon market	E Single buyer agency
Minimum carbon price guarantee at currently expected level, plus existing measures.	Additional incentives for low carbon generation above carbon price.	Regulate to drive decarbonisation	Long term payments to low carbon generators to provide revenue certainty and reduce barriers to entry	Single agency is the only purchaser of all electricity generation – all existing and new, low and high carbon – and only seller of this on to retailers.
Competitive market framework as today	Competitive market framework as today.	Competitive market framework as today	Conventional (and existing) plant trades in competitive market framework.	
Wider measures to reduce barriers to entry in wholesale and retail markets and to ensure security of supply may also be necessary. Under any set of reforms, government will need to ensure access to finance, promote switching, enhance consumer protection and rights and facilitate energy efficiency.				

Marrying this thinking with the government's own published analysis thus implies that the appropriate reforms of the electricity market will be in the 'middle' options put forward by Ofgem and DECC/Treasury. A policy of putting increased (volume) obligations on suppliers or of introducing a capacity payment mechanism, for example, would increase the certainty of relevant volumes being delivered while still leaving much of the decision making on how to deliver that capacity with the market. For those, therefore, who want to deliver the decarbonisation agenda at reasonable cost, and who are still committed to broadly liberalised markets, options in the middle are both politically and economically attractive.

Having said this, enthusiasts for the middle options need to be aware of some of the pitfalls which lurk there. For example, putting enhanced volume obligations on suppliers (Ofgem options B and C) would risk entrenching the position of the existing 'Big 6' vertically integrated generator-suppliers. This could prevent new non-vertically integrated generators entering the market, which would be unfortunate as they could help keep the market 'honest' without continuous and intrusive regulation. At the same time, putting enhanced obligations on the system operator in respect of flexible and back-up plant (Ofgem options B and C) could, in a world with large amounts of intermittent and/or inflexible low carbon generating plant, easily lead to the system operator becoming a de facto single buyer for a large amount of the required generation capacity, a problem for those (the authors of the EMA for example) who think that a single buyer would foster inefficiency.

However, probably the key question in identifying the most desirable options being discussed is whether the key target being aimed for is a volume target or a price target. Is the aim to set the prices/costs which consumers should ultimately bear, with the implied need to then accept the volume determined by those prices? Or is the aim to set the relevant volumes, with the implied need to accept the costs which will then be required to deliver those volumes?

As asserted at the beginning of this paper, and taking the Great Britain (and the broader European) debate about decarbonisation and security of supply at face value, it is clear that the dominant objective is volume or, more precisely, volumes. If the central question underlying electricity market reform is to find the cheapest way of delivering specified volumes, then it is likely that this will best be achieved by adopting mechanisms which are based on volume. Mechanisms based on price (feed-in tariffs or capacity payments based on the cost of new peaking capacity¹³) are likely to end up being more expensive.

This is for a number of reasons. First, because of the asymmetric costs and benefits associated with over-supply relative to power cuts, policy makers concerned with ensuring security of supply will rationally err on the side of prudence when setting prices to achieve a given volume objective, as well as being rationally prudent as to what that target volume should be. Second, policy makers trying to hit low carbon energy targets have an inclination for impatience, especially when the country in question (the UK, for example) is well down

the international league of low carbon energy producers. Third, and especially with power plants such as onshore renewables and nuclear, there are substantial non-price reasons why it may take some time for plans to be turned into commissioned plant – which scratches the itch of policy makers' impatience and makes them more likely to increase the prices on offer. Fourth, driving capacity mechanisms from price, rather than required volume, will increase the exposure of policy makers to rent-seeking procrastination by developers, for example, threats to delay or not go ahead with projects unless the subsidy is increased.

The result of all of this is that price-based mechanisms will have a systematic tendency to err on the side of over-generosity leading to the sort of debates which have been held in various European countries (Spain, Germany and Ireland being examples) about whether success in achieving volumes of MW per se or MW of low carbon generation has been achieved at too high a cost. Driving a mechanism from required volumes and letting competition – between suppliers or through a centrally-run competitive tender on behalf of suppliers – determine the price would be more likely to produce better value for money, subject of course to there being a reasonable amount of competition.

This would argue for the type of mechanism used by the PJM market in the US,¹⁴ for example. In the PJM mechanism, the system operator procures through an auction the difference between (a) the MW which the system operator itself estimates will be required to meet peak demand three years ahead and

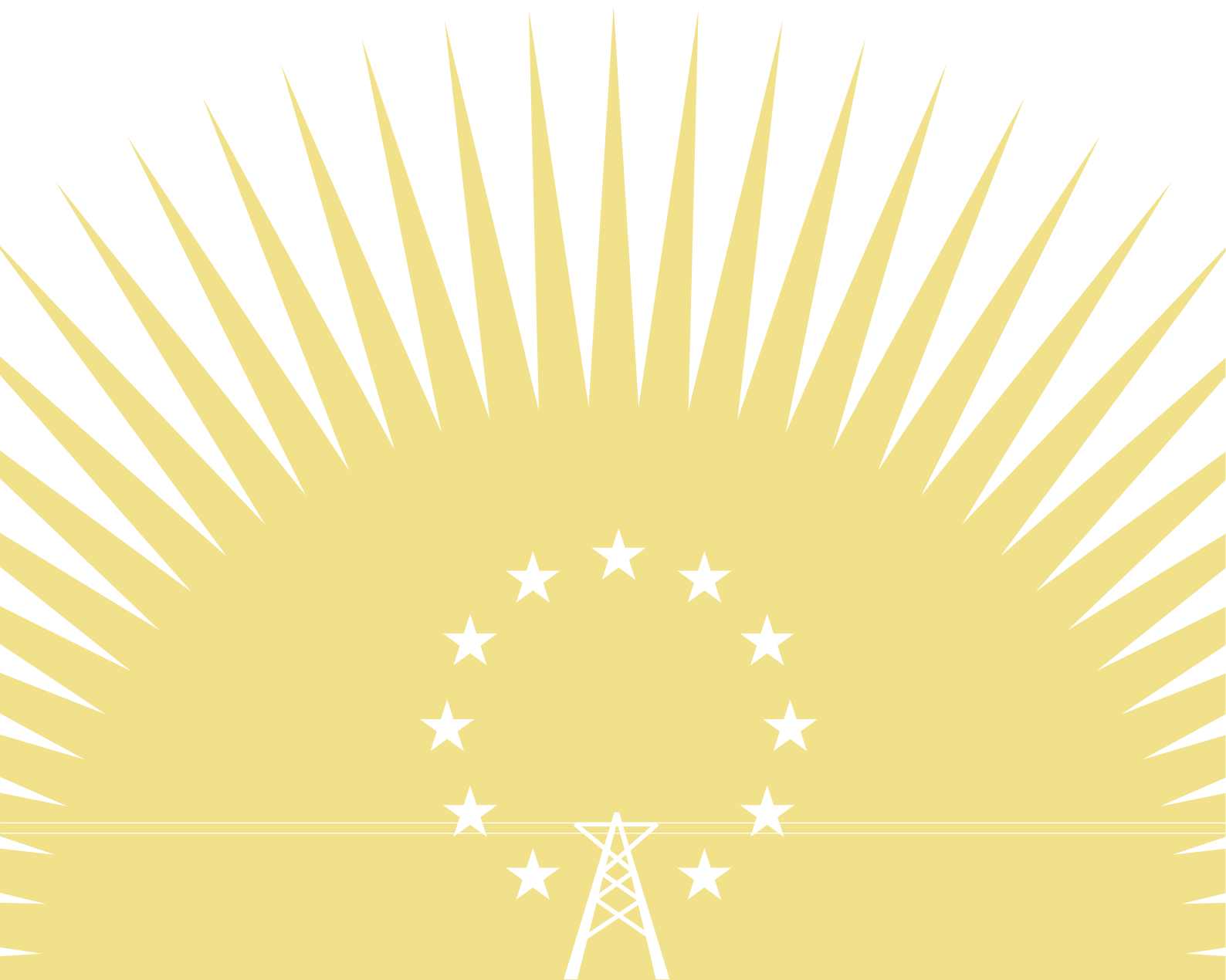
(b) the MW which the relevant companies will already have access to over the same time period. The auction is cleared against a downward-sloping demand curve which means that there are limits to the price which would be paid for capacity, and demand response is included in the auction alongside MW of generating capacity.

Any attempt to import a PJM-type mechanism into Great Britain would have to take account of the greater complexity of the volume objectives in Great Britain, as compared to the US: in particular, the need to hit targets for low carbon energy as well as to achieve manageability of the system with the volumes of inflexible and intermittent capacity that this will entail. The first of these objectives would imply the need for a mechanism targeted specifically at low carbon capacity; the second would probably require enhanced obligations on the system operator in respect of back-up and flexible plant.

In sum, electricity market reform needs to recognise the primary objective(s) which reform is being designed to achieve. If the primary objective is, as it appears to be, to deliver specified volumes of generating capacity of particular types and/or volumes of demand response, and all of this at least cost, then it is likely that the best mechanism will be one which, first, starts from those required volumes and, second, makes best use of decentralised decisions by market participants to deliver those volumes at least cost.

5. Seizing the opportunity: setting us on a path to a low carbon electricity system

Simon Skillings



Designing the market

The concept of a 'designed' market can be difficult to understand: surely markets are about producers competing to identify and meet customer needs? By definition, markets are therefore 'self-designing' and evolve in line with producer innovation and developments in customer requirements, and the outcomes markets produce are entirely unpredictable. However, this unpredictability is precisely where issues arise with electricity markets. The role of electricity in modern society is such that governments deem certain electricity market outcomes to be unacceptable. Most notably, our use of electricity relies on a continuous supply and a system frequency that remains stable on a second by second basis. Governments therefore seek to ensure that electricity markets deliver this outcome by constraining the market through direct interventions which must be 'designed'. In this particular case, an agent is appointed to deliver the outcome (the System Operator) and a set of ex-ante regulations prescribe the tools the System Operator can use, ie balancing mechanism, ancillary services contracts, along with the incentive framework to ensure the desired outcome is achieved at least cost.

Regulatory policy since privatisation has focused on limiting the extent of the interventions, thereby maximising the freedom of producers and consumers to trade as they desire. However, several important interventions have been introduced. These include the requirements on suppliers to acquire a proportion of their electricity from renewable sources and to deploy energy efficiency measures in domestic customer premises. In addition, overall CO₂ emissions from a number of sectors, including electricity generation, are capped at the European level.

It is now necessary to consider whether the existing set of interventions delivers a lean and low carbon electricity system and, if not, where changes must be made.

Accessing low cost finance

The UK electricity market faces an unprecedented challenge. It is now widely accepted that it will be necessary for the electricity sector to be largely decarbonised by around 2030 in order to set the UK on the path to meet 2050 greenhouse gas reduction targets for the economy as a whole. This in turn will involve the replacement of a large proportion of the existing electricity generation fleet with new low carbon technologies, in addition to radical improvements in the efficiency and responsiveness of energy usage. The investment requirements are huge and must be sustained over the next two decades and beyond.

The extent of the investment required is not, in itself, a problem. The real challenge is that investors today are facing an extremely uncertain future environment against which to assess their investments. High investment risk will at best create an increase in financing costs, but there is also evidence that it will significantly constrain the amount of available capital as investors seek to limit the risk exposure of their portfolios. The test for the current market arrangements is therefore whether they are attracting investment of the right sort and extent, and at financing costs that lead to the least overall system cost.

There now seems to be broad agreement that current arrangements are failing in this regard, and there is a need to rebalance risks between investors and consumers. This reallocation of risk would allow a cost effective transformation of the electricity market to be achieved and sustained. This requires policy makers to address two questions: which investments need to be driven forward and which market interventions will materially reduce investments risks.

Policy makers are looking to the twin levers of market reform and a Green Investment Bank (GIB) to create the appropriate investment conditions. A GIB can leverage significant levels of private finance by underwriting certain investment risks. However, the more market

reform materially reduces investment risk, the greater the amount of private finance a GIB will be able to leverage, and the smaller the role it will need to play.

Required investments

Various organisations, including the UK Government, have undertaken scenario analysis for the electricity system over the coming decades and there is emerging consensus around which investments are required. Electricity market transformation requires investment to be focused in three key areas: low carbon resource technologies including both generation and demand reduction through energy efficiency; system security and stability services provided by both demand side and supply side resources; and network infrastructure. Each area will involve a mix of the deployment of mature technologies along with the development of technologies that are currently immature. Investment will be required throughout the value chain, from early stage R&D through to wide-scale deployment of technologies and infrastructure, and the reform agenda needs to address investment risk for a broad range of investors.

Reducing investor risk

Investment decisions will be made on the basis of future expectations of both sales volume and margin. The clear identification of a future sales volume opportunity is particularly important since this initiates the competitive process whereby investors seek to develop or purchase the cheapest technology to meet this market need. Price is a less reliable driver for this market response since it will either be the consequence of future competitive actions or, where it involves an administered subsidy, it is vulnerable to changes in policy.

For the electricity market to be attractive to the full range of investors, it is therefore necessary to ensure that there is a clear and credible long term sales volume opportunity against which potential investments can be assessed. Current market interventions do not set clear long term volume targets in any of the key markets identified above.¹⁵ This suggests that new interventions are indeed required and that the reform agenda should focus on ensuring that key technologies or groups of technologies have a secure long term market. This needs to be combined with the establishment of a clear delivery framework to guarantee that this market need is met efficiently. Interventions worthy of consideration are listed in Box 1.

Potential interventions that would increase certainty and reduce investor risk

- Limits on CO₂ emissions from the Great Britain (GB) electricity sector consistent with the overall decarbonisation objective, perhaps delivered by an emissions performance standard
- Clear renewable generation targets for 2020 and beyond
- Constraints on the energy mix to insulate customers from price or security of supply shocks arising from significant single source technology or commodity cost risk factors
- System reliability requirements based on fixed capacity margin or expected level of un-served energy¹⁶
- Prescribed location of future network investment to match low carbon generation resource potential
- Long term mandatory targets to deploy energy efficiency measures
- Long term requirement for system stability services, such as short term operating reserves

The European Opportunity

At the same time that the UK Government is considering electricity market reform, governments elsewhere in Europe are also reviewing their electricity markets. This is largely in response to the single market agenda and the need to accommodate significant volumes of renewable generation, rather than a perceived problem with investment incentives. However, there is a long term shared agenda that demands that the market reform process in the UK is more closely aligned with the process in Europe. Firstly, the costs of meeting UK Government objectives are likely to be significantly reduced over the longer term if policy objectives can be met using both UK and European based resources. Secondly, a more integrated single European market will deliver the benefits of increased competition and enable new players to enter the GB market. Finally, the UK has inherent advantages in the availability of renewable resources, in addition to the geological conditions that enable sequestered CO₂ to be conveniently stored underground. This gives the UK significant longer term export opportunities in low carbon energy. However, these benefits will only arise if the UK system has sufficient physical interconnections with Europe and the regulatory and market arrangements are in place to enable a genuine sharing of resources.

Integration of EU electricity markets must therefore be a critical design objective of the market reform process. The UK has always led European thinking in electricity market design and the current review process will be keenly observed in other member states.

However, with market designs continuing to evolve across Europe, integration is best achieved through establishing governance structures that mandate the Regulator and other delivery agents to meet their objectives at least cost using resources available from outside the UK. The market arrangements, in particular the balancing market, must have sufficient design flexibility to ensure that they can be adapted in light of integration requirements.

Clearly, the ultimate goal of market integration will require a commonality of approach across member states, and whilst the UK can establish the necessary hooks in governance structures and market design, it is essential that the UK Government remains actively engaged in driving forward the harmonisation agenda. For example, the requirement that network investments are evaluated in terms of their benefits across member states, rather than for one individual member state, requires at least a harmonisation of the statutory objectives of energy regulators and possibly a greater integration of the overall regulatory and network investment processes.

Conclusion

Electricity market reform is a complex topic and discussions tend to rapidly descend into detailed and arcane debates. This can be extremely off-putting for politicians and senior civil servants, who may be tempted to avoid taking significant policy decisions. It is critical to focus on the high level issues: namely, where intervention is necessary and whose job it is to make it happen. The detailed market arrangements can then be developed in line with this high level policy direction.

6. Does an Emissions Performance Standard have a role?

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(This article is written in a personal capacity)

Introduction

The UK's ambitious goal of reducing greenhouse gas emissions by 80 per cent by 2050 can only be achieved by almost completely de-carbonising electricity generation. If fossil fuels are to play any significant role in the generation mix, carbon capture and storage (CCS) will have to be developed, demonstrated and deployed on a massive scale. As of now, we know that the different components of the CCS chain – capture, transport and storage – are individually do-able. But the whole integrated system has never been demonstrated at power station scale. Given the size of the investment required and the lack of technological maturity, carefully designed public policy will be needed to help steer this technology through to commercial deployment in the 2020s. In the longer term, CCS may need to be applied to heavy manufacturing industry and combined heat and power plants as well as conventional electricity generation plant.

Both technology push and demand pull measures will be needed. Technology push support from the public sector is essential to demonstrate CCS. The UK currently plans to support four demonstration projects. However, the debate about demand pull measures is unresolved. All forms of low carbon electricity generation – nuclear, CCS and renewables – would benefit from a reliable carbon price that punishes unabated fossil fuels. The UK's coalition government is committed to a carbon price floor that investors can count on in project appraisal. However, for emerging low carbon technologies a carbon price by itself is not enough to compensate for the market failures in innovation which result in a 'valley of death' before commercial deployment. An Emissions Performance Standard (EPS) may have a role to play in this respect although the detailed design, as discussed below, would be critical.

Is an Emission Performance Standard suitable for CO₂?

Carbon dioxide (CO₂) is a long-lived pollutant with global impacts. In the past, emission standards have been applied to relatively short-lived pollutants with local or regional impacts such as particulates or sulphur dioxide (SO₂). Since it matters little where or when within a year CO₂ is emitted there is a strong *prima facie* case for using a market-based rather than a regulatory approach to restrict emissions. Nevertheless, California has set an EPS of 500g/kWh for CO₂ emissions from new baseload power stations whether located in or supplying electricity to California. The standard is deliberately set at a level that will accommodate unabated gas-fired combined cycle gas turbine (CCGT) power stations (approximately 350g/kWh at full load). An unabated coal station (which might be 800g/kWh or higher) would fail the standard. The effect of the Californian EPS is therefore to lock out long-term high carbon electricity investments such as unabated coal.

There are significant differences between the UK and Californian contexts. California aims to bring greenhouse gas (GHG) emissions back to 1990 levels by 2020. More ambitiously, the UK has set a 34% reduction target for 2020 and in 2011 will set a fourth carbon budget for the period 2023-27. The UK Committee on Climate Change (CCC) and the Low Carbon Transition Plan envisage grid average emissions falling below 100g/kWh by 2030. Renewables and nuclear could make a big contribution, but fossil fuels such as coal or gas will still be needed to provide flexible generation. There will be little or even no space for unabated baseload fossil fuel plant if this level of decarbonisation is to be achieved.



The rationale for an EPS

There is a need to be clear about the rationale for and consequences of an EPS given the prima facie case for a market-based approach. One rationale, as in California, is to lock out long-term investments in high carbon generation. The CCC's view is that: "there is therefore a strong case for buttressing the carbon price lever by establishing a clear and publicly stated expectation that coal-fired power stations will not be able to generate unabated beyond the early 2020s."¹⁸

A second possible rationale relates to technology forcing. The development of catalytic convertors to control vehicle exhaust emissions was the result of setting ambitious standards for which no technological solution existed at the time. US New Source Performance Standards forced the improvement of flue gas desulphurisation (FGD) technology at a time when the technology was immature and unreliable. The Commission on Environmental Markets and Economics Performance discussed mandates as an option for creating early markets and stimulating innovation and investment, citing the Californian Zero Emissions Mandate for vehicles as an example.¹⁹

If technology forcing is the aim, the standard must come before the technology; it is not set once the technology has been demonstrated. Technology forcing approaches will work only when there is no alternative to the technology being mandated. US electricity generators in the 1970s had no alternative but to burn coal and therefore had to develop FGD in order to generate. Vehicle producers had to meet exhaust emission standards to participate in the market. However, nuclear, renewables and gas are all alternatives to CCS on coal-fired plant. The Californian EPS, premised on locking out high carbon generation, will not force the development of CCS while unabated gas remains a lower cost option.

An EPS would also ensure that CCS would actually perform if and when installed. CCS results in a considerable loss in power station

efficiency. If the price of carbon is low it may be more cost effective to bypass a capture unit and run with high emissions or give preference to unabated plant. An EPS could prevent this.

EPS design and unintended consequences

An EPS could have unintended consequences. For example, an EPS of the Californian type would freeze out further investment in coal and incentivise investment in unabated gas. Banning new coal plant would be a simpler and more direct way of achieving the same outcome. However, this would be completely at odds with one of the key goals of UK policy, ie to demonstrate to countries with major coal resources, such as India and China, that CCS is a viable technology. The CCC has recommended that the UK government develop a framework covering all fossil fuels and that new gas plant, as well as coal, be required to fit CCS.²⁰ If, as a matter of broader energy policy, the UK wants to continue to have coal-fired plant in the generation portfolio and demonstrate CCS then a crude EPS is one sure way to thwart these aims.

There could be unintended consequences associated with plant capacity thresholds (eg a 300 MW threshold could result in people building 299 MW plant). Similarly, requiring all CCGTs to be installed with CCS from 2020 onwards would result in a rush to commission plant in 2019. The most serious consequence could be to inhibit investment and threaten security of supply. The UK relies on investment from overseas companies and the wrong EPS design could damage the profitability of investment in the UK. For this reason, an EPS solution should ideally be pursued at the EU level. It will be particularly important not to discourage investment in the CCGTs needed to maintain generating margins when existing coal and nuclear plants close in 2015-16.

EPS design issues

Designing an effective EPS will require extensive consultation with interested parties and analytical support, for example, in the form of electricity system modelling. A perfect EPS cannot be designed starting from first principles.

The relevant facts, such as the age profile of the electricity generation portfolio and the outcome of CCS demonstration activity, need to be taken into account. Any EPS design needs to be rigorously stress-tested to assess the capacity of participants to play the system and to identify possible unintended consequences. However, some broad issues can be identified:

1. The framework needs to cover all fossil fuels, not just coal. Focusing only on coal will be a very effective way of ruling coal out of the generation mix and inhibiting the development of CCS.
2. A uniform EPS across all technologies and fuels measured in g/kWh will not constitute a level playing field. A better approach would be to differentiate an EPS across technologies and fuels with the aim of making the costs of CO₂ abatement broadly equivalent. This will result in a tighter standard for gas than coal when measured in g/kWh and would be analogous to the approach to SO₂ emissions taken under the EU Large Combustion Plant Directive.²¹
3. The balance between rigidity and flexibility needs to be addressed. At one end of the spectrum, an EPS could specify that each generating unit comply with the standard over a relatively short time period – hours or days – by analogy with standards for conventional pollutants such as SO₂. To reflect the long-lived nature of CO₂ in the atmosphere, flexibility could be introduced by extending the compliance period to a year or even longer. Flexibility could also come from creating emission bubbles allowing operators to trade off over-performance at one unit against under-performance at another. Emission bubbles could be extended to groups of generation plant. Finally, operators could be allowed to trade their permitted emissions one with another. But this would effectively create a new emissions trading scheme. If that amount of flexibility is desired the simplest approach would be to tighten the EU ETS caps.

4. Consideration needs to be given as to whether an EPS applies only to baseload plant – and what is meant by 'baseload'. With anticipated investment in nuclear and renewables, the load factor of many UK fossil fuel plants will be low, and will fall further, throughout the 2020s. The economics of CCS drops rapidly with low load factors and a cut-off point would need to be considered unless a very flexible EPS were specified.

5. Over time, there would be a case for progressively tightening an EPS in line with performance improvements and to allow early movers the benefit of less stringent levels.

6. The timing of any announcement of an EPS and the phasing in of requirements would be important. The choice is between early announcements which will provide clarity to the market or waiting to take advantage of knowledge acquired from demonstration projects.

7. Finally, an EPS is not a silver bullet for encouraging CCS and managing emissions from fossil fuels. With CCS unproven at scale, financial support for demonstration projects is still needed to provide the technology push. In addition, a credible carbon price to incentivise all low-carbon generation technologies is critical. However, a third leg to the policy stool is needed and an EPS is one alternative. Other measures more closely linked to electricity market reform – such as enhanced obligations for electricity suppliers or even a central buyer model – could also deliver a secure low carbon electricity system with a place for fossil fuels.

7. Running a low carbon electricity system efficiently

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Over the next ten years, the main focus of electricity market reform needs to be on securing sufficient investment in low carbon generators and adequate flexible back-up fossil plant to complement intermittent renewables. It will also be essential to build the right networks to connect the new wave of generators. As well as thinking about what we build and when, we will also need to start to think about how we run the low carbon electricity system once it is built.

The way that electricity is traded determines which generators are brought on-line or 'dispatched'. Rules that determine how different generators get access to the electricity networks are also important. It is also important to consider how the system is balanced in the final hours and minutes through short term trading and the 'Balancing Mechanism'. The rules under which the system operates penalises non-portfolio renewable generators and will become increasingly unfit for purpose as we move to a low carbon system.

The system rules also have a direct impact on investment. If you are considering making an investment in a wind turbine but are unsure that you will be able to sell your electricity in future or how much it will cost you to access the networks, it increases the risk associated with the project. This may put off developers or increase the cost of borrowing for the project. If a low carbon plant, for example a Carbon Capture and Storage (CCS) plant, is assured that it will be able to run for more hours a year by being given priority in the dispatching process, it may become a more attractive investment and may require lower levels of subsidy.

System operation will also have an impact on the total carbon emissions from electricity generation. If the way the system is operated means that at times renewables are unable to export electricity onto the system, then emissions from electricity generation will be higher.

How does the current system work?

Currently most electricity is sold in the wholesale market under long term bilateral contracts between generators and suppliers. However, as the industry is dominated by vertically integrated energy companies, who have both generation and supply businesses, most energy is traded internally rather than on the open market. Retailers have to forecast future electricity demand from their customers and ensure that they have access to sufficient generation to satisfy that demand. As it gets closer to the actual time of supply, generators and retailers will trade to refine and balance their contractual positions.

Under its role as system operator, National Grid has a responsibility to match generation and demand on a minute-by-minute basis.²² Both generators and suppliers have to let National Grid know how much electricity they are under contract to buy (suppliers) or sell (generators) on a half-hourly basis. These 'contractual positions' are finalised one hour ahead of the actual time of supply ('gate closure').

To recompense National Grid for the costs of balancing the system, both suppliers and generators are subject to imbalance charges if they do not meet their contractual positions. This system is called 'dual cash out' as companies have to pay two different rates depending on whether the mismatch helps or hinders the overall system.

Both generators and supply companies submit bids and offers which set out at what price they would be prepared to increase generation or reduce demand (offer), or reduce generation and increase demand (bid), in each half-hour period. After gate closure National Grid can call on these bids and offers to balance supply in that period, supplemented by the use of contracted reserves, including demand reduction, or energy purchased prior to gate closure. If the system remains unbalanced, National Grid can use a range of other options, including reducing demand via voltage reduction or emergency arrangements.

Generators pay to connect to and use the transmission and distribution networks. If however the networks become too busy or ‘constrained’ in a particular area, National Grid can utilise Balancing Mechanism bids and offers to manage electricity flows and resolve the problem. The constraint costs incurred by National Grid are currently paid for by all users of the electricity network and passed on to customers in their electricity bills (fully socialised).

Problems appear and may become untenable as we move to a low carbon system

So what are the main problems with the current system and how will these change over time as we move to a low carbon system?

Access to the networks is an important factor that affects both the efficient operation of the electricity system and investment in new generation plant. Connecting to the transmission network has been a significant barrier to progress of both renewable and conventional electricity generation projects. Historically access has been on a first come, first served basis and has led to a queue of over 60GW of new generation capacity seeking connection to the grid, with connection dates being offered as late as 2025. A ‘connect and manage’ regime has been introduced so that new generators do not have to wait until the wider network is reinforced before they can connect, which has already significantly reduced the queue. It will also be essential to ensure that the offshore network is built in a co-ordinated and timely way so that it is available for offshore wind projects.

The charges paid by generators to use the distribution and transmission networks once they are connected are a contentious issue. Currently, transmission charges reflect the marginal costs of reinforcements necessary to accommodate new connections; renewables developers have complained about the high cost of charges for those based in remote locations, far from demand. There is also the issue that

transmission charges make no distinction between generation technologies, despite intermittent sources such as wind normally requiring less reinforcement than an equivalent amount of conventional generation capacity. DECC and Ofgem are currently undertaking a review of transmission charges to determine whether they penalise low carbon generators.

In addition there are three main problems with the current market design that affect both efficient system operation and investment, and which that will worsen over time:

- **Bilateral trading may not result in the most efficient generation dispatch.** As vertically integrated energy companies can self-supply, ie use the electricity they generate to satisfy the demand of the customers of their retail arms, the amount of energy traded on the open market is reduced. This reduces both market liquidity and transparency and makes it more difficult for renewable and independent energy companies to participate. Generation dispatch efficiency is also compromised as vertically integrated companies will prefer to utilise their own generation, rather than that of a competitor. In the short term, bilateral trading should continue to function adequately however it will become increasingly inefficient in the medium to long term as wind penetration grows. As the output of wind generators is harder to predict than conventional fossil fuel power stations, energy companies will find it increasingly difficult to internalise the effects on intermittency within their generation portfolios. The amount of last minute trading will increase significantly and increasing amounts of reserve, in addition to that held by National Grid, will be required as a hedge against imbalance charges. It is debatable whether energy companies are in the best position to manage the impacts of intermittency individually, through carrying internal reserves, trading or a combination of both, as they will be unable to take full advantage of the natural smoothing in wind output that occurs nationally.

- **The settlement ‘dual cash out’ mechanism penalises renewables.** If a generator’s imbalance with its contracted position adds to the net system imbalance, for example they generate less than they were contracted to when the system is short,²³ they have to pay imbalance charges that reflect the costs incurred by National Grid in resolving this imbalance. However if they help the system, for example, generate extra when the system is short, they only get value they would have got if they traded in the short term energy market. They get no extra benefits from helping reduce system imbalance, despite the fact that the value of their actions to National Grid as system operator might be far higher. This asymmetry is detrimental for intermittent generators such as wind and small independent suppliers that find it hard to predict output and have little option but to rely on National Grid for balancing. If there was only one price for imbalances, which reflected the actual cost or value of imbalance to the system, wind would win sometimes, lose at other times but it should roughly balance out over time.

- **Growing congestion charges.** The current trading arrangements are bad at handling constraints; it could even be seen to actively encourage market participants to cause them. The current arrangements also make dealing with congestion particularly expensive, which makes transmission reinforcement to reduce congestion appear overly attractive.²⁴ There is a danger therefore that more transmission will be built than is actually required, adding to the cost of integrating renewables in remote areas such as Scotland. Constraint costs are much higher under the current market arrangements – as much as £150/MWh – whereas under the pool they were often in the range £5 to £15/MWh. The need to adopt more efficient arrangements for dealing with constraints is made more urgent by the move to a ‘connect and manage’ access regime. While this change was vital to enable new generators to get onto the system quickly, congestion will increase substantially and,

without more efficient and cost effective arrangements for dealing with that congestion, unnecessary cost will be incurred.

The best way to address these three problems might be to move to a more integrated market design, as for example is adopted in parts of the US and Spain, where all energy is traded on an open market administered either by National Grid or a market operator. Generation would be dispatched centrally to meet demand rather than by individual energy companies, and wind output would be aggregated nationally reducing forecast error and reserve requirements. While market participants would still be incentivised to minimise imbalances, all imbalance would be cleared at a single price which reflected the cost or value of that imbalance. As generation would be dispatched on the basis of marginal cost, it may be necessary to give dispatch preference to low carbon sources to ensure that generation such as biomass or CCS, which may have significant marginal costs, is not displaced by high carbon emitting generation. A more integrated market deal, with network congestion much more effectively managed, would allow energy and reserve requirements to be fully coordinated and provide a highly liquid and transparent market for dealing with intermittency. Importantly, an integrated market would remove the current bias in favour of vertically integrated energy companies and remove the barriers to entry for small and independent players.

1 le reduce unnecessary electricity use and make services currently provided by electricity (eg light, IT services, motors etc) more efficient. There may however have to be an increase in electricity for other new services that aren't currently deployed widely such as efficient electric heating (through heat pumps) and electric vehicles.

2 Other factors such as grid and planning have also played a role in increasing the cost of renewable deployment in the UK.

3 A standard or fixed feed-in tariff (FIT) provides electricity generators with a fixed payment or tariff for every unit of electricity they generate. Currently in Great Britain, certain types of electricity generators (qualifying renewables under 5MW and micro combined heat and power plants under 2kW) receive a FIT for every unit of electricity they generate. Generators can choose to get an additional set export tariff for every unit of electricity they export to the grid or they can opt to sell their electricity into the market. As such a standard or fixed FIT is not linked to the wholesale electricity market price. A premium FIT however is linked to the wholesale price as it offers generators a premium in addition to the wholesale price. Premium FITs can take a number of different forms: as a percentage of wholesale market price, a fixed amount above the market price or as a variable rate dependent on the market price.

4 The bubble concept refers to the capping of total CO₂ emissions from a fleet of power stations over a year. This allows operators with multiple units to decrease emissions from one unit and increase emissions from another unit, as long as overall emissions are equal to or under the limit.

5 The Hirschmann-Herfindahl index is the standard way used by competition authorities to measure market concentration. It is calculated as the sum of the squares of the market shares of each of the participants. If the score is greater than 1800, the market is categorised as 'concentrated'. For example, if there are five companies in a market each with a 20 per cent market share, the Hirschmann-Herfindahl index would be $5 * (20 * 20) = 2000$.

6 Surrey, J. (Ed.), 1996, *The British Electricity Experiment*. Earthscan, London, pp. 138–163.

7 This generated a 'loss of load probability' (LOLP) which was very small except when the margin between supply and demand was small. At the point when supply was just insufficient to meet demand, all generators would get £2.40 for every unit of electricity they bid in.

8 Green, R., 2003, *Failing electricity markets: should we shoot the pools?* Utilities Policy 11, p155–167.

9 Thomas, S., 2006. *The British model in Britain: failing slowly*. Energy Policy 345, p583–600.

10 The Climate Change Act 2008 set a legally binding target of at least an 80 per cent reduction in greenhouse gas emissions by 2050, relative to 1990 levels, to be achieved through action in the UK and abroad.

11 HM Treasury and Department of Energy and Climate Change, March 2010, *Energy Market Assessment*, http://www.direct.gov.uk/prod_consum_dg/groups/dg_digitalassets/@dg/@en/documents/digitalasset/dg_186447.pdf

12 Energy Market Assessment, paras 4.65-4.66.

13 As, for example, with the capacity mechanism in Ireland's Single Electricity Market (SEM).

14 PJM Interconnection is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

15 There is some expectation that the banding parameters under the Renewables Obligation will be adjusted to give an overall share of the power market for renewables of around 30% by 2020, but even this involves a degree of presumption and there is no certainty at all as to what will happen beyond 2020.

16 Unserved energy is the probabilistic level of demand that cannot be met because there is insufficient supply capacity.

17 The author gratefully acknowledges comments on an earlier draft of this article from colleagues including Hannah Chalmers and Jon Gibbins at the University of Edinburgh.

18 Committee on Climate Change, December 2008, *Building a low-carbon economy – the UK's contribution to tackling climate change*, TSO, London, p xxiv.

19 Commission on Environmental Markets and Economic Performance, November 2007, *Report of the Commission on Environmental Markets and Economic Performance*, BERR/ DIUS/DEFRA, p45.

20 Committee on Climate Change, 17 June 2010, Letter to Rt Hon Chris Huhne, Secretary of State for Energy and Climate Change, <http://hmccc.s3.amazonaws.com/gas%20CCS%20letter%20-%20final.pdf>

21 The European Parliament and The Council of the European Union, 23 October 2001, *Directive 2001/80/EC on the limitation of emissions of certain pollutants into the air from large combustion plants*, http://eur-lex.europa.eu/LexUriServ/site/en/oj/2001/L_309/L_30920011127en00010021.pdf

22 Much of the complex administrative procedures involved are contracted out to Elexon. The administrative costs are recovered from generators and suppliers through Balancing Services Use of System charges. Source: NAO

23 System is long if electricity supply is greater than demand. System is short if supply is less than demand.

24 New transmission can be justified up to the point where the marginal cost of investment equals the marginal savings in constraint costs accrued by building the transmission. Thus, the unnecessarily high costs of constraints allow you to justify more transmission.

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