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Low Carbon Electricity Investment: The Limitations of Traditional Approaches and a Radical Alternative

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Abstract Moving to a very low carbon electricity system is central to meeting the goals of UK energy policy, and indeed to the wider global challenge of tackling climate change. This will require massive investment in low carbon electricity sources. This working paper identifies four key difficulties with the current mainstream approach of relying on the impact of a carbon price in the present liberalised electricity market, supplemented with additional incentive mechanisms like renewable obligation certificates and feed-in tariffs. We then summarise alternate mechanisms and propose a new approach, aimed at harnessing the potential interest and capital of electricity consumers, large and small, directly in funding low carbon electricity investments, in the form of long-term 'Green Power' contracts that operate in a separate, differentiated contract market.

Keywords Electricity, Renewables, Climate Change, Green Power

JEL Classification Q41

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Low-Carbon Electricity Investment:

The Limitations of Traditional Approaches and a Radical Alternative

Tim Laing[1] and Michael Grubb

EPRG Working Paper

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1. Introduction

Electricity is a vital part of our energy system. It is a high-grade energy carrier that is used in buildings, across industry and increasingly in transportation. It is both a final good that consumers buy - to power light bulbs, computers, fridges etc - and also an input into almost all industrial processes, including very electricity-intensive processes such as the production of aluminium.

Electricity's importance in our energy systems has grown rapidly in the last four decades, with use of electricity growing 275% from 1971 to 2007, increasing its share of our total final energy use from 8% to 17% (IEA 2010). Factor in losses associated with generation, transmission and distribution, and electricity accounts for 33% of all primary energy production, and an even greater share of global CO_2 emissions (IEA 2010).

Looking forward our global demand for electricity is likely to grow even further, with strong demand from the emerging economies, and increasing numbers of people gaining access to electricity across the poorest parts of the world. IEA projections of global electricity demand imply increases of as much as 70% by 2030 in baseline scenarios (IEA 2009).

Electricity also represents a major challenge, tool, and opportunity in our attempts to curb greenhouse gases, and their potential impacts on the climate. Approximately 40% of Carbon Dioxide emissions from fuel combustion today come from the use of electricity. Without policies in place to limit emissions this share is likely to rise as much of higher future electricity demand will be met by coal-based generation predominantly in China and India. The IEA (2009) project that electricity could contribute 44% of all CO_2 emissions by 2030 in their reference scenario.

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Despite these problems electricity could form an important part of the movement towards a low-carbon world. Heat pumps, which run off electricity, provide large efficiency improvements over current heating technologies (Stafell 2009). Electric vehicles for transportation would help to reduce demand for diminishing conventional oil supplies. Both of these technologies could dramatically cut greenhouse gas emissions, but only if there is a low or zero carbon power system in place.

With these potentials in mind the production of a low-carbon (or even zero-carbon) power system is a necessary (though not sufficient) part of the long-term move toward low carbon economies, a theme repeatedly stressed both by academics and government advisory reports such as the UK Climate Change Committee.

The production of a low-carbon electricity system is likely to require the deployment of many different technologies, some of which we have in our generation mix today, and some still to emerge:

- Renewables, both established like hydro-electricity and wind, and in development like Concentrating Solar Power, have a big part to play. Wind could meet 30% of total generation by 2050 (GWEC 2008).
- Nuclear power could remain an important, and in some countries growing part, of the electricity mix
- Fossil fuel generation with Carbon Capture and Sequestration (CCS) is also predicted to play a substantial role, albeit with technological uncertainties. Some projections suggest CCS could account for 10% of total generation already by 2030 (IEA 2009).

A common characteristic of most of these low carbon technologies is that they are very capital intensive (though CCS may also have relatively high operating costs), as shown in section 3. They require both investment and innovation, and yet currently struggle to attract investment in competitive electricity markets without the kind of dedicated support that has been afforded to renewables – much of which accrues to wind energy rather than wider renewables developments.

Creating the right incentives to trigger adequate investment and innovation in the face of technical and regulatory risks are crucial to designing effective policy. This paper briefly touches on the traditional approach that has been put forward for creating these incentives. We then cover a range of issues that arise with the use of this approach. We then examine complementary approaches, and consider a radical alternative: the creation of a viable, additional low-carbon electricity product, with separate contractual conditions, which may contribute to solving some of these problems. We note some of the issues this may raise, and suggest an agenda for further work on this possibility.

PART I: PRESENT POLICIES AND CHALLENGES

2. The traditional approach

The traditional approach to the challenge of creating a low-carbon economy is to introduce a price of carbon, either via a cap-and-trade scheme, such as the European Union Emissions Trading Scheme (EU ETS) or through a carbon tax. The theory of carbon pricing is broad and well established, based upon the principle of pricing negative externalities (Pigou 1950; Baumol 1972). It creates flexibility over what type of abatement occurs and where and when it happens, helping to find the most cost-effective options.

The pricing of carbon increases the price of carbon-intensive products, changing relative prices, and increasing demand for, and therefore investment and innovation in, low-carbon technologies. Unfortunately our experience to date is that although carbon pricing has incentivised efficiency improvements (Hoffman 2007) and switching from coal to gas generation in the EU, via the EU Emissions Trading Scheme (Neuhoff 2008), there is little evidence of the level of investment and innovation we require.

One factor in this is the volatility associated with the carbon prices arising from a cap-and-trade scheme. The introduction of a carbon tax or price floor in cap-and-trade schemes have been the main proposals for reducing this volatility. Earlier work by the authors (Laing and Grubb 2010) shows that although price floors may improve investment incentives, the choice between tax and cap-and-trade is not the central issue behind the lack of investment in new low-carbon technologies.

Cost, capital intensity and risk differ between conventional generation (such as coal and gas) and low carbon options (like wind and nuclear). These differences mean that the relative economics of different sources depend upon contractual structures, as well as relative prices. In short-run competitive markets with a relatively high cost of capital, the carbon price required to induce large-scale investment in low carbon sources may be too great for current politically acceptable levels of carbon pricing.

The cost of renewable technologies is likely to continue falling due to innovation and learning-by-doing arising from deployment, reducing the price differential (Jamasb and Köhler 2008). This has motivated the introduction of technology-specific support policies such as feed-in tariffs or tradable renewable permits (such as the Renewable Obligation Certificates). We discuss these in the next section, but argue that these represent a second-best solution which risks storing up trouble for the future.

The situation we now find ourselves in (in Europe at least), is a mix of carbon pricing, technology-specific support mechanisms and targets for renewable power. The interaction between these instruments is troublesome, and how well this mix can meet the challenges associated with a move toward a low-carbon electricity system is a matter of debate (Gan, Eskeland et al. 2007). There are at least four specific challenges associated that arise with this policy mix.

3. Low-carbon electricity and investment

Creating a low-carbon electricity system requires a huge capital investment over the coming decades. The UNFCCC (2007) estimate that a total of $695 billion of investment is required, globally, in energy supply up to 2030 in order to meet its mitigation scenario. Replacing existing plant requires large investments, and the nature of low-carbon technologies implies that capital costs and thus the investment required will be higher than using conventional technologies.

The liberalisation of electricity systems has been very effective in driving down the costs and prices associated with operating existing systems, but less effective in attracting new investment. In countries such as the UK and the US, where there has been new-build power stations this has concentrated on Combined Cycle Gas turbines. These have short build times, and relatively low capital costs, with the main costs from the gas burned to produce the electricity.

Zero carbon sources are very different. Almost all of the costs of wind energy are related to the capital costs from constructing the turbines. Once the turbines are built, costs are low: there is no fuel, only operation and maintenance (O&M) costs. The scale of the different shares of investment, O&M and fuel costs between fossil-fuel based generation and some low-carbon options are shown in Figure 1: capital accounts for more than half the levelised costs for nuclear, wind and solar alike, in sharp contrast to conventional options. A move toward any of these low-carbon generation options implies a radically greater capital intensity.

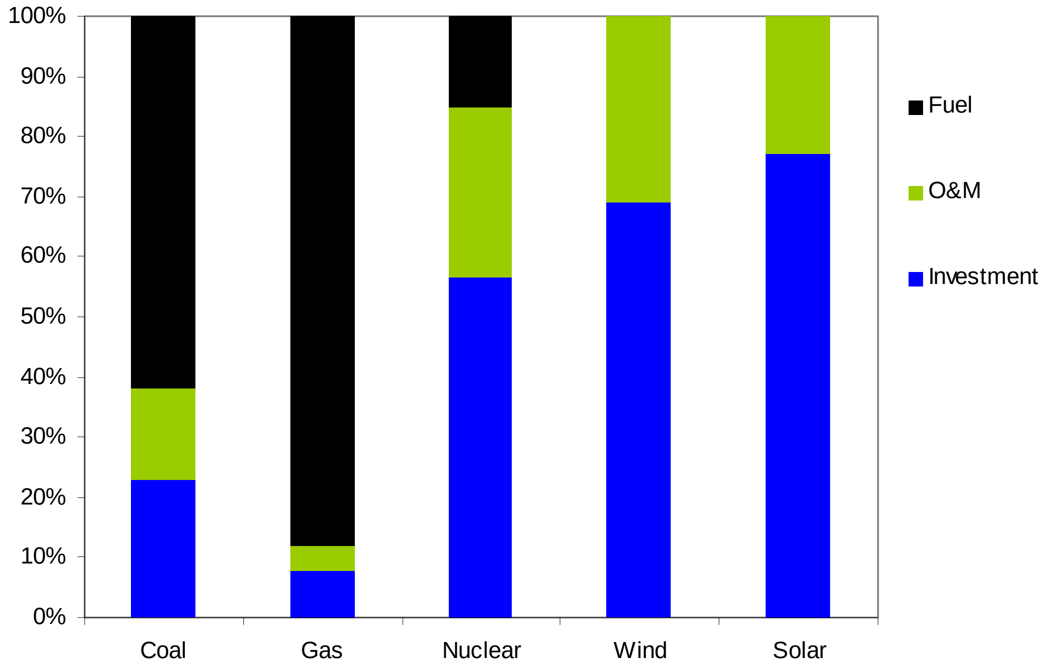

Figure 1: Composition of levelised generation costs at 5% discount rate Source: (IEA 2005)

This has two crucial implications:

- Zero carbon sources will tend to operate as baseload, ahead of fossil fuel sources, because they are cheaper to run and need to run as much as possible to recover the cost of capital;
- The cost of capital is all important to developers of low-carbon electricity and is crucial to determining the cost of, and our ability to move towards, a low-carbon electricity system.

The cost of capital to generators depends on a number of factors: the balance between debt and equity financing; market conditions; and not least the risk and uncertainty related to the returns on investment. Returns to investment in low-carbon electricity generation depend upon the electricity price, along with any additional support policies. In competitive wholesale electricity markets, such as that that exists in the UK, the price is set by the marginal unit of generation. In the UK this is predominantly gas or coal-fired generation.

Crucially, this means that *the price at which a low-carbon investor can sell its product bears little or no relation to its own costs.* It depends instead upon the volatile prices of coal, gas and carbon faced by the fossil fuels generators (Roques, Nuttall et al. 2006).[2] In economic terms, zero carbon sources are all infra-marginal, but in the absence of other measures will receive a price set at the margin over which they have no control – and very limited capacity to predict. .

This potentially raises the cost of capital, increasing overall costs and reducing incentives to invest, for the very sources that are central to low-carbon futures. The importance of the cost of capital to overall costs for different types of generation can be seen in Table 1. Doubling the cost of capital (discount rate) from 5 to 10% increases the overall cost of capital-intensive generation, such as Nuclear and Wind, by around 50%, while the price of coal- or gas-fired generation increase by much smaller percentages. At 5% discount rate, nuclear and wind can compete comfortably; at 10%, they are fundamentally uneconomic – and the cost of forcing a low carbon electricity system would itself be about 50% higher.

$/MWh	Coal	Gas	Nuclear	Wind
5% discount rate	$27.1	$39.3	$30.1	$31.1
10% discount rate	$36.5	$42.8	$46.5	$47.8

Table 1 Projected Electricity Generation Costs US power plants Source: (IEA 2005)

[2] In the UK the ROC scheme means that renewable generators receive a ROC for every MWh of power produced that they can subsequently sell. The price of the ROC depends on the amount of renewable generation in the system and the government defined buy-out price, neither under the control of the low-carbon investor.

Creating a reliable investment environment, with a low cost of capital will be crucial in the move towards a decarbonised power system.

There are two main policy support mechanisms (alongside carbon prices) that have been used to support investment in renewables:[3]

- Feed-in-tariffs offer a guaranteed purchase price, above and beyond the wholesale power price, to generators of renewable power. There is often a defined declining time path of prices to give long-term stable investment signals.
- Tradable renewable certification programmes, like the UK's Renewable Obligation Certificates (ROCs), require all electricity generation companies to hold and surrender a given amount of certificates, granted for generation from renewable power. If a company does not generate sufficient renewable power from its own portfolio it must purchase certificates from other companies with excess certification, or, in the case of the UK, pay a pre-determined price into a buy-out fund.

Both programmes have encountered difficulties. The UK ROC scheme, established in 2002, grew out of an earlier Non-Fossil Fuel Obligation scheme, intended initially to subsidise operation of the established nuclear fleet. It has ran into criticism over the cost of the scheme, but also the fact that it has failed to generate the projected levels of renewable generation, with the growth of onshore wind especially sluggish (Pollitt 2010). This is due to various hurdles (including planning and grid connection issues), but also reflects the fact that the ROCs are a complex structure that overlay the spot electricity price, doing nothing to reduce the cost of capital.

Feed-in tariffs, which do greatly reduce the financial uncertainties, have been much more effective, but not without problems. Feed-in tariffs have supported rapid growth of renewable energy in a number of countries. Spain introduced a feed-in-tariff programme in 1997 that has evolved through several different forms (del Rio Gonzalez 2008). In 2008 this programme ran into difficulties in the face of huge growth in the industry due, in part, to the reduction in the price of solar panels, along with the generous tariff. The tariff was not vintaged, increasing the scope of projects that fell under it, and its associated budgetary impact. In the wake of fiscal difficulties the government was forced to slash the tariff by 30%, bringing the industry to a halt over night (Deutsche Bank 2009).

Germany introduced a similar scheme in 1991, with tariffs linked to electricity prices. In 2000 this was amended to set out fixed prices for 20 years. The budgetary problems as a result of the credit crunch led to discussions of adjustments to the tariff for new generators, and the tariff was cut by 12-15% for different types of generation (NewNet 2010). Although this has not impacted those who have invested previously it does impact those projects in the pipeline yet to be developed.

[3] For a full discussion of the two instruments see Butler, L. and K. Neuhoff (2006). Comparison of Feed in Tariff, Quota and Auction Mechanisms to Support Wind Power Development, Cambridge Working Papers in Economics.

These cuts help highlight the political difficulties associated with generous feed-in-tariff regimes in the wake of wider fiscal problems. This may limit their use in the immediate future in the wake of the credit and debt crisis.

The intent and justification for these support schemes was most fundamentally the idea that they would foster innovation and the growth of new industries, in which technology-specific support could be phased out in favour of broad-based carbon pricing. But *in addition* to the problems encountered, there remains a more fundamental question about the 'convergence to market' model.

Carbon pricing and ROC-type policies are overlays to market structures which rest fundamentally on conventional generation technologies, which have low capital costs and variable (and relatively higher) operating costs. This is the reverse of the characteristics of the low-carbon system we are trying to create, where capital costs dominate and running costs may be very low. Patterson (2007) has coined the term 'Infrastructure Electricity' to describe this kind of power.

To understand the tension between the two types of generation, consider this. UK scenarios for decarbonising the power sector imply that the UK system should get about 90% of its electricity from zero carbon sources within 20 years, from a massive investment programme in renewable and nuclear costing potentially up to £100bn. This is a staggering scale of investment, and yet the existing approach implies *that this should be financed on the basis of future electricity sales at a price that has nothing to do with the cost of all that investment,* but is a function of gas, coal and carbon prices – maybe with added ROC incentives (that are due to expire within about 15 years) - over which the investors have no control and limited foresight.

With this risk inevitably driving up the cost of capital, it is likely to prove a very expensive way of funding £100bn of investment – if indeed it works at all, which is clearly in doubt. Moreover, the uncertainty arising from a system in which the price is set by a very small fraction of the generating fleet cuts both ways. Even if there was investment on the scale sought, the net outcome 'left to the market' would be one of two things: a combination of interest rates, fossil fuel and carbon prices insufficient to service the capital; or the opposite, with the owners attracting vast windfall profits in periods of the opposite conditions. With both the carbon costs, and the market structure, being largely political constructs, neither outcome is likely to prove politically acceptable - leading inevitably to patch-up, interference and controversy.

Funding massive investment in infrastructure electricity through short-run spot markets based on fuel and carbon prices, in other words, is inherently very problematic. A market structure designed to support low carbon, capital intensive investments might look very different from the spot market system we have today, if it is to provide greater stability and security for the long-term infrastructure-type investments required.

4. Innovation in electricity

To meet our future electricity demand in a low-carbon and affordable manner we require innovation across a range of technologies. Yet the electricity sector has suffered from a lack of innovation and investment in Research and Development (R&D). The R&D intensity in electricity is just a tiny fraction of that in the most innovative sector of pharmaceuticals and software and computer services (Figure 2).[4] Much of the current technology embodied in generation, transmission and distribution is based upon the technology used a century ago.

The reasons for this have been inadequately studied, but there are likely to be several mutually reinforcing explanations. One is the sheer scale and technological risk associated with the heavy engineering implied in converting large amounts of power.

Another plausible factor was the fact that for most of last Century, power systems were run as regulated monopolies. It was hoped that liberalisation would inject more innovation. In terms of operating practices, it has; and yet liberalisation has been accompanied by further collapse of R&D expenditure, as investors sought quick returns.

Overlaying these is the fact that electricity is the ultimate homogenous good. At the point of consumption, all electricity is the same. This means that there is little product differentiation in electricity. Different prices may be offered to households and industry, and there are some time-of-use price differentials for example the Economy-7 tariffs in the UK that offer cheaper overnight tariffs. But generally the electricity we consume is all the same and priced in the same manner.

This lack of product differentiation greatly reduces the incentive to innovate. A new way of generating electricity has to compete purely on price against incumbent technologies that have benefited from decades of development, economies-of-scale, and regulatory adaptation. They might be aided by a carbon price, but that – a price differential, driven and constrained by politics – is the sole basis on which an innovation has to recover all of the costs and risks of its R&D.

Thus new innovations in electricity can't command a large economic margin by exploiting a monopoly position with captive consumers (which is basically what patents guarantee for pharmaceutical innovations); nor they can open a whole new class of consumers eager for the latest innovation (which is how IT products command equally large margins). Yet innovation on the scale we see in the pharmaceuticals and Information Technology and Communications fields is what we really want for the challenges ahead.

[4] Although it depends on the definition of the electricity sector, for example Siemens are captured in the Electronics sector, yet some of their products may be applicable to the electricity sector.

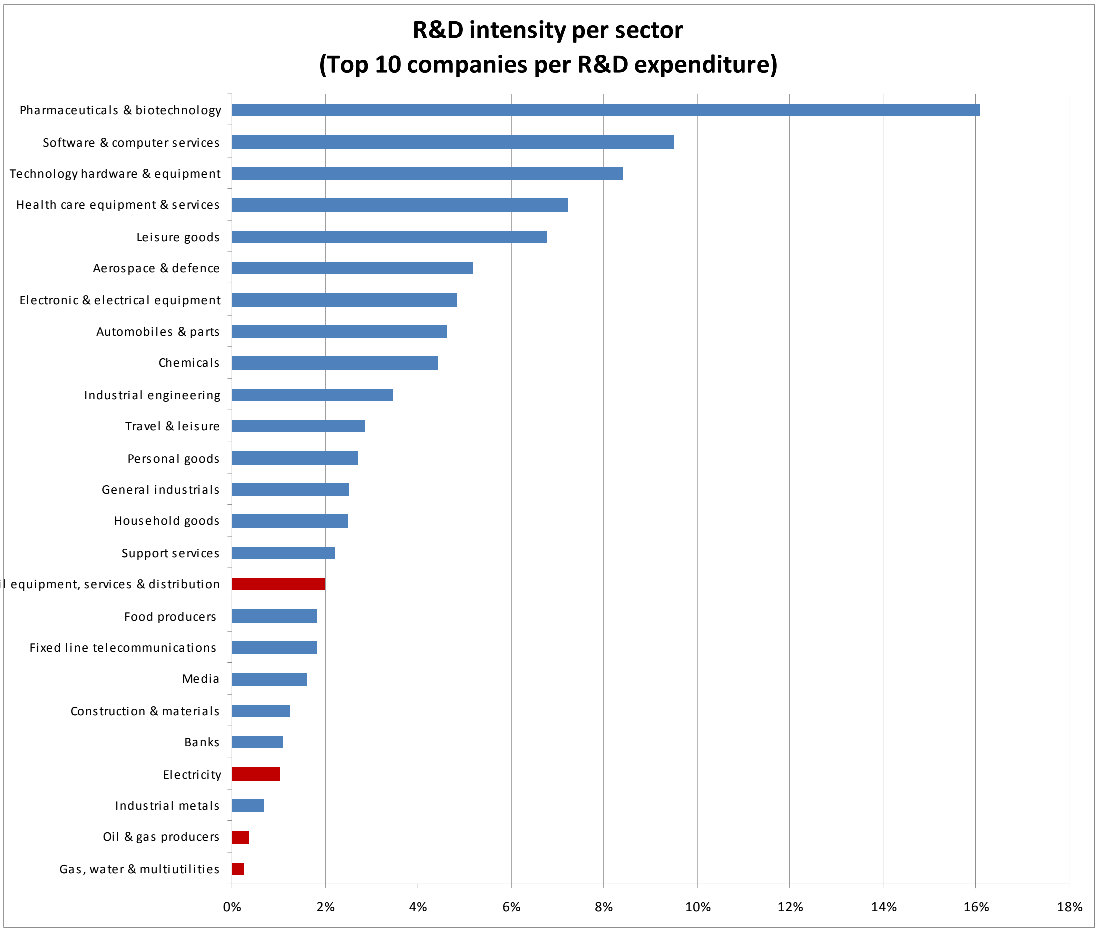

Figure 2: R&D intensity per sector (Department of Innovation, Universities and Skills 2008)

Product differentiation can help create market niches. These can help create learning economies stimulating development and diffusion of the product (Unruh 2002; Raven 2007). There is a natural market niche in electricity for renewable or low-carbon power. In our current market structure consumers struggle to purchase electricity from this niche. The UK's Renewable Obligation Certificates (ROCs) scheme, that mandates a certain level of renewable generator per supplier, does create some demand from suppliers for renewable power. This is not really analogous, however, to the power of wider market demand from not only individual households, but perhaps more importantly large businesses and industries. The proposal we explore at the end of this paper offers an attempt to open up such a consumer-driven market in innovation for low carbon electricity.

5. Electricity prices, carbon leakage and carbon attribution

Carbon prices increase the cost of fossil-fuel based generation and in competitive markets the cost increase of the marginal generating unit passes through to wholesale electricity prices. Evidence from the EU shows that between 60-100% of the opportunity costs from carbon prices from the EU ETS have been passed through to wholesale electricity prices in Germany and Netherlands (Sijm, Neuhoff et al. 2006).

These price rises translate to increases in tariffs for both households and industries.

In terms of economic incentives the pass-through of carbon prices is desirable, but gives rise to fears of 'carbon leakage' in two forms:

- In principle, there could be leakage of electricity production itself, importing electricity from regions without a carbon price. This is not a significant problem for the UK, where there is very little international trade in electricity. It may look different for east European countries (though electricity capacity across eastern borders is currently limited, except for the Baltic states), or indeed Southern Europe if there is growing transmission capacity across the Mediterranean.
- The more immediate concern is about the potential for higher electricity costs to drive electricity-intensive industrial production abroad.

Carbon leakage has become a huge political debate in the EU, in the context of impacts from the EU ETS, and also in the discussions over introducing carbon pricing in the US (McKinsey and Ecofys 2006; Droege 2009). Carbon leakage threatens both the environmental efficacy of carbon price regimes, and also the political acceptability of them, as not only emissions leak, but also jobs.

Electricity plays a crucial role in many industrial processes. The most extreme case is aluminium. Over 80% of emissions from aluminium are from electricity, and they represent about 4% of total emissions from the EU ETS. The scale of these emissions implies that aluminium producers face high costs from the introduction of carbon pricing (Renaud 2008).

Aluminium firms could relocate outside carbon pricing schemes if the burden of costs they face from carbon pricing is high enough. The majority of Aluminium production in the EU procures its electricity from long-term contracts, many of which expire shortly (Renaud 2008). On the expiry of these contracts Aluminium smelters face higher prices due to electricity price increases from the EU ETS unless they can renegotiate special contractual terms that exclude a carbon price – or bluntly subsidised in other ways to stay in Europe

Should an aluminium smelter shut down production and move abroad there would be leakage of jobs (although limited given the employment levels in smelters), but whether such movements actually cause carbon leakage depends on how electricity is generated inside and outside the carbon pricing regime. If an aluminium smelter which uses coal-based electricity (or from a grid dominated by coal-based generation) moves abroad to a country where the electricity is predominantly from hydro-electric generation (such as Brazil), then there is in fact a reduction in global emissions – and 'clean leakage' – though detailed attribution remains problematic partly because of displacement effects.[5] If, however, the aluminium smelter relocates to a country where the electricity is predominantly from coal (India, China or Australia for example), then there would be leakage of emissions.

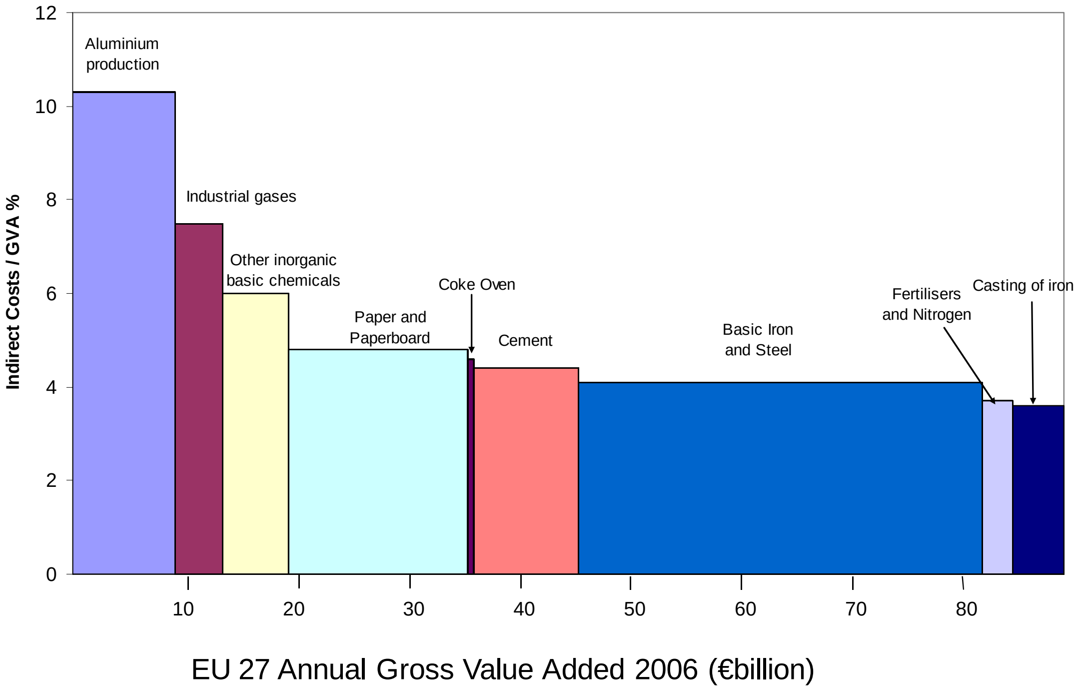

Figure 1: EU GDP per sector versus increased costs from carbon pricing impacts on electricity (Source: Eurostat and EU Commission)[6]

Aluminium is the industry that faces the biggest impact from increases in electricity prices, but is by no means the only one. Figure 3 shows the increases in costs from electricity use as a percentage of gross value added from a €30/tCO_2 carbon price in the EU. These indirect costs from electricity prices are small relative to the direct costs from emitting CO_2 directly (which can be as high as 60% in the most impacted sectors), but they are not insignificant. The electricity-related costs would add more than 4% of Value Added to the cost of industrial gases, inorganic basic chemicals, paper and paperboard - and also steel electric arc furnaces (subsumed under basic iron & steel in the diagram).

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[5] The majority of aluminium imports into the EU are from Russia and Mozambique (Droege 2009) for which the major power sources used for aluminium smelting is hydro, implying leakage of emissions may be small. However a more detailed analysis is required in order to determine whether leakage of emissions takes place. A smelter in Russia or Mozambique that expands production may draw the additional power from a coal power station, or may draw extra power from a hydro-electric plant that subsequently cannot be used to power other buildings or industries which require extra coal-based generation instead. This implies that in the context of our current systems it is the marginal generator which is important in determining the emissions caused.

[6] Total annual gross value added from the sectors amount to 1.4% of total EU 27 GDP in 2006. Indirect cost estimates are from Results of the quantitative assessment of sectors at NACE 4 level. Accessed from http://ec.europa.eu/environment/climat/emission/carbon_en.htm

In Phase I of the EU ETS, allowances were freely granted to all industries, including electricity, but this did not protect electricity-intensive industrial consumers. Carbon costs in electricity were anyway passed through to consumers, yielding huge windfall profits for the industry (IPA Energy Consulting 2005). Free allocation 'downstream' to cover indirect costs from electricity price rises has been ruled out as an option by the European Commission.

Border-levelling of carbon costs has been proposed as a better approach to tackling carbon leakage (Quirion and Monjon 2010). Imports of goods into the scheme would face the cost of the carbon embodied in their production, while exports would receive a rebate for carbon costs they faced. Border-levelling could either be in the form of taxation, or require the surrendering of allowances under a cap-and-trade scheme. The legality of such border-levelling under the WTO is still a matter of debate, and much would depend on the level chosen to base the border-adjustment on (Ismer and Neuhoff 2007).

Border levelling is however much more difficult for electricity-related costs. WTO legislation dictates that border levelling must be non-discriminatory. Trying to charge for carbon on the basis of actual carbon emitted would be difficult enough; it would be even hard to attribute this to a specific carbon intensity of electricity drawn from a power grid. . Where electricity grids are connected, there would be a theoretical case for trying to charge carbon at the marginal carbon intensity, but this would also create innumerable difficulties in practice. How connected is connected? What really is the marginal unit? What if marginal carbon intensity exceeded the carbon intensity paid for in the EU (in which case the border level would seem to contravene the other core WTO principle of National Treatment)? Moreover, levelling at the "marginal" rate may raise other political difficulties since this would generally be higher than the average – it would be hard to explain, and almost impossible to defend, a border adjustment that benefited EU producers by charging imported aluminium more than the grid average – especially if that producer claimed to be based on zero carbon power.

The emerging literature on border levelling suggests starting with a fixed "benchmark" based on the carbon intensity of the best available technology. However for electricity-intensive products, the best available technology from a carbon emissions perspective would involve zero carbon power, with no carbon costs, negating the point of the border levelling.

And for export adjustments, it would be similarly hard or impossible to get consensus on the level of adjustment, unless a producer could plausibly demonstrate direct association with a specific power source and a trail of the carbon costs incurred.

The only border levelling that would make sense is if thus producers themselves could prove direct association with specific power sources, and hence provide a realistic measure of carbon intensity. This is not possible if industrial producers buy from a national (or regional) spot market – or indeed, if they buy electricity that is intrinsically 'pooled' with the rest of the system.

This story tells us that tracking the carbon in electricity is important for assessing leakage, and in designing any border-related measures that might be used to help tackle it. Unfortunately, the fact that the electricity grid smears out different carbon intensities of electricity into one average means that levelling border costs in relation to the type of electricity used is impossible, removing the incentives for firms to stay within the scheme, avoiding costs by purchasing low-carbon electricity.

No amount of supply-side support – carbon prices, feed-in tariffs, etc – can overcome this problem, indeed they make it worse by raise the difference between domestic and foreign electricity prices. Only a direct assessment of the carbon content of the electricity consumed, that also allowed for a switch to low-carbon options, could create the right incentives for firms to both remain in the carbon pricing area, and purchase their electricity from low-carbon sources.

6. Consumer interest in low carbon electricity

Some consumers, groups, and companies would value the potential to use low-carbon electricity. Harnessing the power of consumers' purchasing power in driving the transition to a low-carbon electricity system could help drive the innovation required and raise the political acceptability of the undertaking. The importance of consumers' role in the process of moving to a decarbonised world is discussed in McNamara and Grubb (forthcoming).

Empirical evidence of the willingness of consumers to pay for green energy exists for the US and the UK (Roe, Teisl et al. 2001; Rose, Clark et al. 2002; Diaz-Rainey and Ashton 2008; Longo, Markandya et al. 2008). This willingness to pay may represent pure altruism or a warm glow effect, where consumers value voluntarily donating to the provision of public goods (Andreoni 1988; Andreoni 1990). Menges, Schroeder et al. (2005) examine the balance between these two motivations for green energy and conclude that there is a warm glow effect for purchase of 'green' electricity in a significant number of electricity consumers.

In the UK consumers have a range of green tariffs that offer 'green electricity', we examine these in more depth in Section 7. Initial uptake of these tariffs has been small, just 319,000 in 2009 (OfGem 2009), but harnessing the willingness-to-pay of consumers offers an opportunity for creating a niche market in green electricity that could contribute to learning and innovation.

Although capturing household demand for renewable electricity may help the transition, greater benefit may come from capturing the desire of large businesses to purchase renewable power.

The best example of this comes from an examination of British Telecom. As a diversified telecommunication company it demands electricity for a wide variety of purposes. It accounts for approximately 0.7% of UK's energy use, making it the

UK's biggest single consumer of power (Sherriff 2007). Since 2007 it has been pursuing a strategy of investment in renewable power. However in June 2008, guidance issued by the UK's Department for Environment, Food and Rural Affairs (DEFRA 2008) prohibited companies from claiming credit for purchasing electricity through green tariffs in carbon accounting or environmental reporting, for the reasons explained in section 8.

For example, companies falling under the UK's Carbon Reduction Commitment (a tradable permit scheme that covers the emissions of commercial and public sector organisations including BT) have to count all their electricity use purchased from the grid at a single emissions grid average , currently 541gCO_2/KWh (DECC 2010). Only on-site renewable generation can avoid this, creating an obvious distortion.

BT has argued strongly against this advice and has continued its purchasing of renewable electricity, and investment in its own wind turbines (Utility Week 2008; ClimateBiz.com Staff 2010), but is unable to secure any financial benefit from its efforts to purchase low carbon electricity and even the "CSR" benefits it can legal claim are carefully circumscribed, as outlined in section 7.

The reality is not that all customers treat all electricity the same. There is a diversity of electricity customers, with varied willingness-to-pay for a product they believe to be "environmentally clean". Creating a market system where large consumers of electricity can purchase low-carbon electricity and claim credit for these purchases in voluntary, and most importantly, regulatory regimes could help create market-pull for low-carbon electricity (Diaz-Rainey and Ashton 2008). This is not possible with current approaches. In the final section of this paper, we outline one approach to enabling this, the potential benefits, and the issues that it might raise. First however, we take a brief look at other approaches to incentivising low carbon electricity investment.

PART II: COMPLEMENTARY APPROACHES

This part of the paper considers complementary and alternative approaches to try and address some of the challenges noted above. We take as context a desire to move forward, not reverting to a centrally planned system directed ultimately by government investment. We regard rather the challenge as being what the options might be to develop market structures that could rise to the considerable challenges identified in Part I.

7. Strengthening the carbon price signal

The UK has been amongst Europe's leaders on both electricity liberalisation and climate change.

In electricity regulation, the UK blazed a trail in unbundling previously centralised systems to inject competition wherever it seemed viable. The short term result was a radical reduction in costs (including unfortunately R&D), a surge of investment in combined cycle gas turbines, and a proliferation of suppliers competing for customers. Reduction in CO_2, driven by the displacement of old coal plants and some increased plant efficiency, was a significant side benefit. The basic idea of liberalisation and competition has spread more widely across the EU, albeit with complex variants.

The UK also aspired to be among Europe's leaders on climate change. It had a precursor to the EU ETS and has pushed for its strengthening. It also had a relatively early scheme to promote renewable energy, in the Non-Fossil Fuel obligation (NFFO), which helped to launch renewable energy as a significant industry during the 1990s. The NFFO was succeeded by the tradable 'renewable obligation certificates' (ROC) scheme, designed to set the maximum level of renewable generation in the grid. For 2010/11 this was set at 10.4%, the level at which suppliers present ROCs.

An EU-wide carbon price, combined with a system designed to secure a specified level of renewable energy, would seem to be about as good an environmental combination as one could possibly hope for. Unfortunately, it's turned out to be a lot more complex than that. This is partly because of weaknesses in the ROC scheme and the EU ETS outlined in Part 1.

The core weaknesses of the EU ETS are ascribed to its low and volatile prices, and sequential structure of cap-setting, with the resulting investment uncertainty injected by this. The EU has attempted to address the latter problem by setting out caps not only for Phase III (until 2020), but indicating a default trajectory for capped emissions to decline at 1.76%/yr continuing thereafter.

However, price remains uncertain, and well below the level required to support the kind of major capital commitments implied by efforts to radically decarbonise EU electricity over the next two decades. Two main remedies to this have been discussed in the literature.

One is to set a *floor price* – simultaneously with an indication of the intended price path over relevant (multi-decadal) timescales. This could best be implemented at the EU level through reserve prices on auctions of EU ETS allowances (Grubb 2009). If this proves impossible, it could still be achieved at Member State level by underpinning the price with, for example, a carbon tax.

The other approach, proposed for example separately by both Newbery,[7] and by Helm (House of Commons 2006), is for *carbon contracts*. These would be project-specific contracts in which the Treasury would sign a contracts-for-differences on the carbon price, in effect guaranteeing a minimum carbon price to investors.

The economic logic for such carbon contracts appears impeccable: risk over the carbon price is largely created by political decision making, thus it makes sense for the political system to underwrite the risks if it wants private sector investors to assume a particular level of ambition. There are implementation challenges

[7] Reference sought

arising from the project-specific nature of the proposal, but these are probably eclipsed by the raw political fact that the UK Treasury has shown no willingness to take on the liabilities that carbon contracts would imply. The Treasury may desire a high carbon price, but not to the extent of being willing to underwrite a price largely outside its control using UK taxpayers money.

The underlying thinking on these proposals is that the key challenge is private sector confidence in future carbon prices. In practice, we are a long way from carbon prices that would be adequate to support most renewable energy sources, let alone diversity in emerging renewable sources – and investors know it.

The various renewable support schemes thus complement the EU ETS by providing additional subsidy to investors. The ROC scheme proved relatively ineffective in its original form and is now mired in complexity of various developments to compensate for this – targets set deliberately at unachievable levels to ensure it operates at a "capped price", and banding so that less mature technologies receive greater incentives. Feed-in tariffs are much simpler – though as noted in section 4, they themselves have suffered major complications, with revisions injecting more investor uncertainty, and their much trumpeted effectiveness may come under much more scrutiny as the volumes rise further and political systems awake to the costs.

A core observation is that most of these improvements – carbon floor prices / fixed prices / contracts, and renewable supports with increasing trade-offs between the price confidence and costs implied, are targeted at the first of four issues surveyed in Part 1: investment. They do little for innovation – a lack of which has resulted in the UK and EU launching major publicly-funded innovation programmes to try and compensate for the lack of private sector R&D in the sector. And they do nothing for the accounting of carbon or carbon costs in industrial products, or engagement of consumers. Indeed, on the last of these it turns out that they have achieved exactly the opposite.

8. 'Green electricity tariffs': the UK situation

The implication of the UK ROC scheme is that the purchase of renewable generation by consumers or business does not actually add any more renewables to the system than that which would have occurred anyway, since it operates under an overall renewable energy cap.[8] It is not additional, unless there is retirement of the ROC associated with the renewable generation.

This problem of additionality is one of the reasons for the DEFRA advice of June 2008 regarding green electricity tariffs that constrain companies claiming credit for buying 'zero carbon electricity'.

[8] This is unless all suppliers have met their level of Renewable generation, a situation that is yet to occur.

A further issue that has arisen with the use of green tariffs in the UK surrounds attributability. Any low-carbon electricity that is sold must be matched with the same amount of low-carbon electricity generated. This does not mean that physically the electrons have to be from low-carbon generators, but that the amount sold is the same as the amount generated.

This raises tricky questions, as renewable power sources, such as wind, are variable and electricity demand fluctuates from minute-to-minute. The nature of electricity means that supply and demand needs to be matched at every point, so it might be possible that the wind drops and demand spikes at exactly the same point, meaning that at that second low-carbon demand cannot be matched with low-carbon generation. This implies that perhaps we should think of accounting for it over a longer-time period.

Two examples from the UK offer potential options. The UK's Climate Change Levy is a tax placed on energy delivered to non-domestic users. Energy from new renewables is exempt from the Levy, and must be accompanied by a Levy Exemption Certificates. Suppliers who provide levy exempt tariffs are required to provide balancing of Levy Exemption certificates with energy sold under the tariff. This need not be instantaneous. There is an initial 3 month balancing period. At the end of this period if the energy sold balances, or is less than, the amount of certificates held a new balancing period begins. If the amount of energy sold is greater, the balance is carried forward into subsequent periods, up to a limit of two years, at the end of which any outstanding Levy payments must be settled (HMRC 2010).

The UK's fuel mix disclosure regulations, which requires suppliers to provide information on the mix of different generation types used to produce the energy they sell offers a different model. The fuel mix is balanced over a total of a year, with disclosure based upon total generation mix over that time period (OfGem 2005).

Despite the issues of additionality and attributability consumers in the UK can purchase a range of green tariffs.[9] There are products on offer from the six major electricity retailers, EDF, EON, British Gas, Npower, Scottish Power and Scottish and Southern, and products at three small independent green-only retailers, Green Energy, Good Energy and Ecotricity. In 2009 it has been estimated that 319,000 customers purchased these green tariffs and the UK regulator, Ofgem launched guidelines and a certification scheme for the market in February 2010. The guidelines are voluntary and only applicable to tariffs for domestic and small and medium enterprise customers. These guidelines attempt to traverse the difficulties associated with low-carbon power that we have touched on.

In order to qualify for the certification scheme a tariff must satisfy four categories (OfGem 2009):

[9] Industrial tariffs are not available, chiefly due to the difficulties associated with the Climate Change Levy.

- Transparency – 'tariffs need to be clear and consistent with public understanding as to what constitutes green supply'
- Evidence of supply – 'suppliers will need to have and retain evidence, .., to verify all claims regarding both the source of the electricity supply and additionality'
- Additionality – 'customers choosing a green tariff need to be able to be satisfied that their support is contributing to additional environmental benefits or additionality'
- Accreditation – 'suppliers who have signed up… will be required to agree and develop an accreditation scheme'

The additionality component does not require retirement of ROCs, or ETS allowances, merely an additional environmental benefit equivalent to a pre-defined amount of CO_2e abatement per customer. In theory, electricity could be truly "green" if it required retirement of both ROCs and CO_2 allowances, but this would make it prohibitively expensive (Graham 2006) - the buy-out price of ROCs in 2010 is £36.99/MWh comparable to wholesale electricity prices, and over a quarter of domestic electricity prices. But this is because it would be trying to address the problem of additionally specifically – not the underlying problem of creating a stable investment framework that lowers the cost of capital. In piling one uncertain, policy-driven market upon another, it risks amplifying the inefficiencies and market risks, and consequently, the cost of capital.

There are currently ten domestic tariffs and two small business tariffs that are certified by the scheme, from seven different suppliers. Notably two of the dedicated green energy companies, Ecotricity and Green Energy are not certified by the scheme. A summary of the tariffs on offer in both the scheme and outside are summarised in Table 2.

The tariffs offer different products to demonstrate additionality, chiefly investing in green funds that invest in renewable generation. Only two tariffs offer any retirement of ROCs, and neither anywhere near 100%. British Gas' Future Energy Plus retires ROCs equivalent to 12% of electricity supplied, while Good Energy retires the financial equivalent of 0.05 ROCs per MWh.[10] Most tariffs do retire Levy Exemption Certificates.

The issue of attributability becomes clear when we look at the three small dedicated green energy companies. Only one of these three, Good Energy, offers 100% renewable, zero-carbon power to all of its customers. However this may have hindered their growth as a business. As they state on their website: 'We have never turned away a domestic customer but we have been forced to turn

[10] This works out as less than 5% of ROCs per electricity supplied as the ROC has more value than the payment needed to the buy-out fund for not having a ROC. By submitting a ROC you are entitled to a share of the total buy-out fund, and so the full financial value of the ROC depends on the size of the buy-out fund.

away a couple of really huge businesses - this is because our 100% guarantee is never compromised.'[11]

A 100% guarantee of mainly intermittent renewable power may become more problematic if demand for the product grows. The two other suppliers, Ecotricity and Green Energy top-up their renewables with grid supply in the former, and Combined Heat and Power in the latter. This allows them to meet demand when intermittent renewable supplies are low.

The UK situation highlights the difficulties for consumers in the current system. Identifying truly green electricity in the current regulatory context is tricky if not impossible. This has led to the limiting of the ability to claim credit for green electricity purchases by business and industry, dramatically reducing potential demand. Remedying this situation could help harness this demand potentially helping to address the investment and innovation challenges.

Finally, if we think about low-carbon power more broadly than renewables the problem of additionality is exacerbated by the EU ETS. This has set the level of carbon emissions across the sectors that it covers: power generation and industry. The purchasing of low-carbon electricity simply allows greater emissions to take place at some other place within the scheme. The only effect is to reduce demand for EU ETS allowances, reducing the price. Thus in order for purchases of low-carbon power to contribute additional emission reductions retirements of EU ETS allowances is also required.

9. Low-carbon electricity as a separate product

One effect of the developments during the 2000s is an apparent emerging conflict between the agendas of liberalisation, and the environmental agenda. Fundamentally, governments are increasingly trying to engineer investment that would not happen in a purely competitive market, by adding more rules, incentives, and constraints. There seems to be an increasing risk of the environmental agenda unrolling the liberalisation agenda and pushing us back towards centrally planned power systems.[12] When we reflect on the nature of the electricity market we have created – aimed to minimise costs and risks on short term financial perspective driven by shareholder interests – this is not so surprising. It suggests a deeper level of challenge that needs to be considered.

A theoretical ideal (removed from reality)
The creation of a genuine differentiated electricity product in which all production could be assigned to individual consumers would be an interesting theoretical proposition. If consumers - industries, businesses and households - cared about the difference, this could do much help to overcome the problems of innovation, investment and leakage we have touched on above, and harness the investment power of consuming industries such as BT. Identifying and

[11] Good Energy – Your questions answered at http://www.goodenergy.co.uk/about-good-energy/your-questions-answered/
[12] Reference sought – Malcolm Keay

differentiating clearly the carbon content of electricity supply could be extremely useful in applying border levelling instruments. Would it be possible to differentiate grid-based electricity supply in this manner?

To do so in full is an interesting intellectual exercise but appears to pose insuperable problems. Electricity is a completely homogenous good, the electrons are identical, no matter their place or type of production. In a grid-based electricity system it is physically impossible to say that the electrons bought by a company or individual come from one plant rather than another. It is only with a dedicated line from the power plant to the factory can a company say for certain that their electricity comes from one source rather than another. The grid smears out different carbon intensities into an average that varies from minute to minute as demand for electricity rises and falls and the generating mix changes. Figure 4 shows the mean hourly generation carbon intensity of the UK grid in one week in May and June 2010. The peak of the grid intensity is 70% higher than the lowest point. If we look over long-time periods, seasonal variations drive these differences even higher.

These differences mean that accurately defining the carbon content of electricity supplied is very difficult. Using a single grid average is the main methodology we have today but is an imperfect solution. A large electricity consumer who demands their power at off-peak times may in fact have a much lower carbon footprint than if their emissions from electricity were calculated using a grid average. With a grid average there is no incentive to buy low-carbon products or green tariffs, or to shift electricity use to time of day with lower carbon intensities.

Again in theory, one could envisage a system in which all electricity supplied must be bundled with the emission allowances used to generate it – tracked all the way from every generator, to every consumer, every minute. This could result in such a differentiated market. But the nature of the challenge noted suggests it is impossible: it would require unimaginable levels of complexity in the systems, and unbelievable levels of sophistication by consumers to handle and express preferences in relation to a limitless variety of continually time-varying carbon intensity of electricity offers – and a legal obligation to retire the associated emission allowances. And passing the carbon on to consumers would remove the incentive on generators themselves to avoid carbon costs – they would pass not only the price, but the carbon liability, on to the consumers, placing all the incentives on the consumer side. We have not been able to identify any credible way of achieving such full "carbon transparency" in electricity systems.

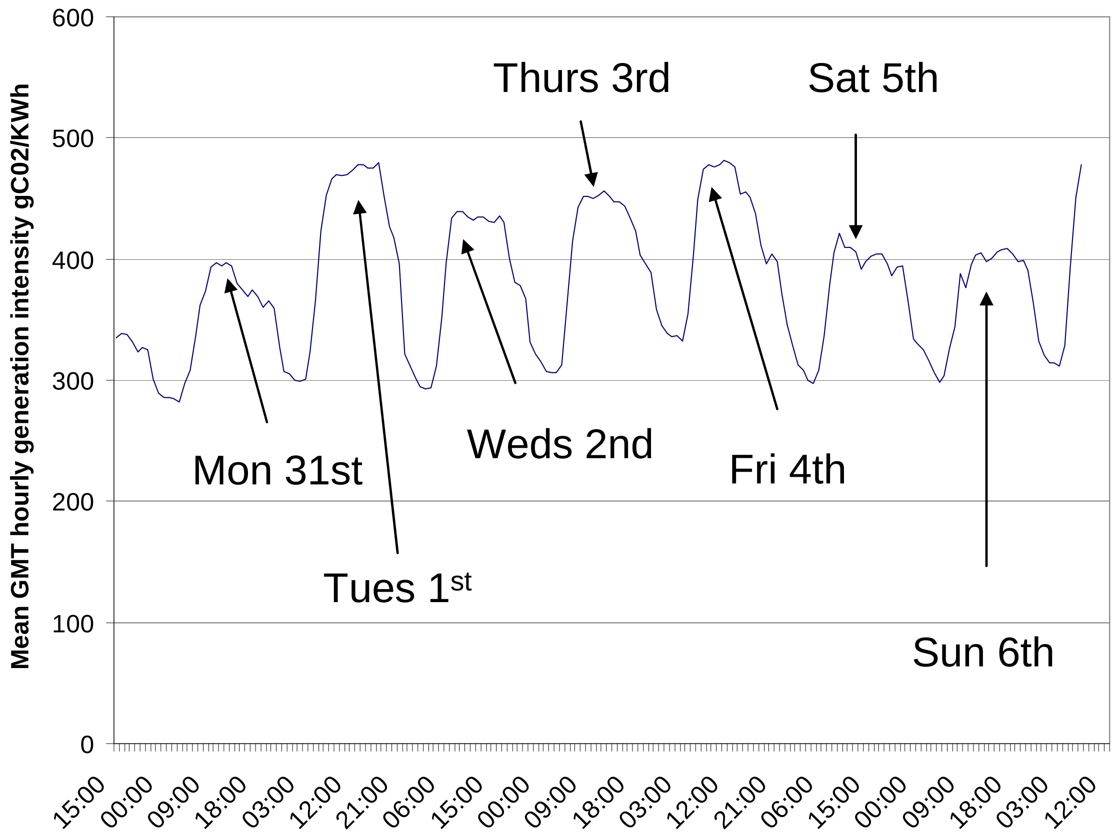

Figure 2 Carbon intensity of the UK grid week beginning May 31 2010 (Source http://www.earth.org.uk/_gridCarbonIntensityGB.html)

A long term, zero carbon electricity contact market: the basic idea

However, there is another and much simpler option – to establish at least a consistent contractual basis that could allow a basic level of differentiation, by developing a second kind of electricity market – one designed to allow purchasers to associate in consistent ways with zero carbon electricity investments. Specifically, we propose that systems should be established to facilitate the development of a market for long-term, zero-carbon power contracts – a specific, regulated contracted 'green power' market, which could operate alongside the mainstream conventional power market.

For specificity, let's call it a 'GP Contract Market'. It would require active regulatory and policy decisions in several dimensions. To secure investment, such contracts would have to be long term; current regulations are designed to encourage the opposite, by facilitating (and sometimes mandating) the ability to switch. However, a long-term contract on the generator side does not necessarily preclude the ability to trade contracts (which might be particularly relevant as an option on the consumer side). To be clean, the entire accounting framework would need to clearly delineate such GP contracts from the rest of the power system, including in terms of its carbon intensity.

Such a differentiation would allow firms holding such GP contracts to claim credit for purchasing low-carbon power in calculating their carbon emissions, either for regulatory or voluntary purchases. This would increase the incentive for firms to purchase and invest in low-carbon power, and allow those who would like to, such as BT, to purchase and claim credit for it. It could provide a means for those consumers who wish to pay extra for renewable power to make the purchases they desire. It is thus an extension of market principles – not the reverse.

Moreover, with some specific low-carbon power capacity linked through long-term GP contracts, this would also facilitate (though not resolve entirely) the dilemma of disincentives under the EU ETS cap. The cap for post 2020, for example, could be explicitly debated in terms of electricity sector emissions *net of the volume of GP contracts*; such contracts could thus legitimately claim to be contributing to ongoing carbon emissions, by reducing the demand for carbon-based generation and thus facilitating tougher carbon caps on the rest of the system over time.

Note that the carbon market remains central to the economics of this approach. As the carbon price rises, the *relative value* of GP contracts would correspondingly increase. But the financing of the power investments would not be at the mercy of the fluctuating markets in coal, gas and carbon; they would be securitised through long term contracts that reflect the cost structure of the generating sources in that GP contract market, not the fluctuating spot price determined by current fossil fuel and carbon prices.

Thus, in terms of the four challenges discussed in Part 1:

Establishing such a GP contract market would reduce the financing costs, and thereby reduce the cost of *investment* in low-carbon electricity. To use Patterson's term, this parallel market would be better suited to the 'infrastructure electricity' that new green power will supply. Long-term contracts for green power could be based on their own costs, and allow more certainty in repayment of the large initial capital costs, reducing the cost of capital.

The product differentiation from such a division could create extra incentives for *innovation* into low-carbon power, and help to create the missing demand-pull for low-carbon technologies from consumers, both large and small.
Such differentiation could also help create a system in which major industrial consumers, such as Aluminium, could accurately and legitimately establish a basis for avoiding carbon costs. Adopted more widely, this might provide a way for any border adjustments to legitimately focus on carbon-related costs: charging imports, unless producers could produce evidence that they were drawing power from zero carbon electricity contracts, in which case they could be exempt. All this could facilitate the use of policy instruments such as border levelling, helping to reduce the risk of carbon leakage, and the associated undesired environmental, and social consequences.

Finally, this would provide a way in which diverse, large-scale electricity consumers could express their potential preference for low carbon power in the market - without the extraordinary and unsatisfactory hoops that have emerged to avoid double counting for existing schemes to small consumers, and the de facto ban on large consumers entering at all. It would thus provide a ready alternative to the bizarre situation in which the UK – which whilst extolling the need for a rapid and costly transition to zero carbon sources, specifically prevents the major companies participating in the Carbon Reduction Commitment from claiming any credit for investing in zero carbon power.

The challenges

Given these potential advantages, is it possible to create such a differentiated market, and could this be done in the context of our current regulatory regimes?

There are a number of hurdles that would need to be overcome. Such a product would need to prove additionality to the system as a whole.

The product would need to ensure that low-carbon power sold is matched by low-carbon generation over a suitable time period, although as we discussed within the UK we have models for this already. The creation of a separate low-carbon product alongside standard grid electricity would require the carbon intensity of the mainstream electricity market to be calculated separately for use in regulatory instruments like the CRC, or in voluntary carbon footprinting – with separate accounting for the electricity denominated in long-term low carbon contracts.

Nature and precedents.

Of course, long-term contracts are nothing new. Indeed, they already exist in the electricity arena. The Finnish contract under which pulp & paper industry contracted to a new nuclear power plant, underwritten by AREVA, is the most famous recent example – but not an encouraging one, given the scale of delays and cost overruns.

This reflects one reason why such arrangements are rare. A contract between an individual buyer (or a fixed consortium) and a single power plant poses big risks for both sides. A generating company that builds and operates the plant faces the risk of having a single purchaser, while the counterparty is dependent on one single power source, with the inherent risks involved:

- If the buyer goes bust, the power plant is exposed – this has been a major reason cited why most generators have not pursued long term contracts with some of Europe's major industrial consumers. In a globalising world, and witnessing the struggles of European heavy industry, the longevity of a specific industrial plant is just considered too risky to finance a major power plant construction;
- If the contract is focused on a single huge new power plant, the buyer is exposed if that goes wrong – as with the Finnish reactor.

The danger is that the these risks could inflate the cost of capital above and beyond that financed by alternative instruments, such as feed-in-tariffs that are backed by governments, reducing their effectiveness.

There is one other major example in Europe, which seems more relevant, namely the French Exeltium contract (see box). However, even this reflects rather special circumstances and it may be neither feasible, nor necessarily desirable, for this exact model to be more widely replicated.

The core argument of this paper is that long-term contracts are desirable – contrary to the prevailing orthodoxy - but that they need to be embedded in a structure that would facilitate trading of such contracts. Structured in the right way, making long-term contracts tradable can reduce risk to both generators and consuming parties. Potentially, industries could then buy into such contracts from existing qualifying plant without having to wait a decade for their construction.

Creating a tradable contractual structure would be crucial to such arrangements, allowing firms to acquire or divest such contracts as market situations dictate, within prescribed rules that protect the underlying financing requirements. This would require governmental monitoring of the system, but is not dissimilar to some of the roles government plays today in some other markets, and in monitoring fuel mixes of energy suppliers.

The great difficulty with such an idea is the potential diversity of such contracts – how would one trade a 15-year contract with one finance and risk structure with another of 20 years and a completely different finance and risk structure? Some degree of diversity is probably necessary and healthy, but the need for some liquidity in such a contract market structure would imply two things: a need for a publicly defined framework for a limited number of "qualifying" contract types; and as wide a market as possible. For the latter reason, it is something that would best be developed at a European level.

More specifically, there needs to be a process that establishes a basic structure of such contracts, and that facilitates competition *between those entities that are interested in securing stable, zero carbon long term power contracts.*

The French Exeltium contract.*

In this contract, a consortium of electricity intensive industries combined to structure a long-term partnership with energy producers. This cost to the consuming industry electricity deal. The total value is €4bn, funding a 24-year contract with EdF. Four French banks led a consortium of ten banks to provide a €1.7bn loan, supplying electricity to the syndicated consortium of about three dozen heavy electricity consuming industries. The deal reached financial closure in April 2010.

The cost to the consuming industries are differentiated between a fixed part at the start of the contract reflecting the investment cost, and a variable part in line with operating costs of the plant. Thus, the cost structure of the Exeltium contract broadly matches that of the generating plant, considerably reducing the cost of capital.

By some pooling of demand (with a consortium of consumers), some of these risks are reduced; the electricity supply risk is underwritten through EdF.

However, there seem to be major obstacles to the wider use of such contracts.

One relates to political and legal acceptability. The Exeltium contract required approval from the European Commission, which was granted after considerable negotiation. However there was strong indication that this was considered to be an exception (presumably aided by strong support from the French government) and that in general such contracts would face difficulties as they are perceived as potentially anti-competitive.

Another obstacle is that the conditions themselves are not so easily replicable, reflecting as it does the nature of the relationship between French industry, banks, and EdF, mediated to a large degree by the French government.

The proposal in this paper is not that the Exeltium experience should itself be replicated, but rather that the underlying objective –long term contracts between suppliers and consumers of electricity – has potentially multiple benefits. Policy can learn from such experience, and rather than impede should facilitate more generic tradeable long-term contractual structures, and engage a wider group of electricity consuming organisations, more explicitly linked to the huge task of decarbonising European power generation.

*Sources: Reuters, 13 Apr 2010; Simon Cotterill, Presentation to CBI Energy Conference, 2009.

Why link the long-term contract market to zero carbon power? Fundamentally, because of all the reasons set out earlier in this paper:

- decarbonising power generation is one of the major public policy challenges of our times, and low carbon generation is almost all very capital intensive and infra-marginal;
- the electricity system suffers from insufficient innovation in general, and specifically in relation to low carbon innovation given the industrial discounting of political uncertainties around the carbon market; a market for long term contracts could widen the space and incentives for innovative approaches,
- the ability to demonstrate zero carbon generation in legally secure, verifiable and trackable ways is crucial to including power-related emissions in any system of border adjustments; and
- there are a substantial body of electricity consumers whose interest might be driven partly by the desire for low carbon power.

This last point is crucial. Such a GP contract market would offer a ready means of enabling a company like BT to secure zero-carbon electricity – and test whether they are really willing to pay the price. But many other "non-traditional" buyers might enter such a market – including consumer-facing organisations like TESCOs or Marks & Spencer, which have displayed a strong interest in the green agenda, and are also starting to market electricity to consumers under their own brand.

One open question is how to design such a market interface in open competition with standard grid electricity. Long-term contracts are illegal in the domestic market and clearly, given the rules facilitating switching of suppliers. Individual consumers are most unlikely to be participants in long contracts anyway, but there may need to be re-examination of the rules defining what entities should operate under such rules. At some scale, preventing or impeding mutually assenting parties from entering long-term contracts can no longer be presented as a way of preventing market abuse, but risks instead impeding another sort of competition – one which might be far better suited to fostering the investments required.

Another key question is how such a GP contract market would relate to existing support structures, notably for renewable electricity – and linked to this, how large the demand for GP contracts might be.

On the former: clearly, if a country has a mandated renewable energy cap (as in theory does the UK) that it is set to achieve, then GP contracts could only increase the renewable energy investment if they retire credits (ROCs in the UK case). However even in the UK the system is subject to a "cap price" so there is some possibility that GP contracts could result in additional renewables investment. Under feed-in tariffs, the question is more basically whether any renewable energy investor would wish to sign such a contract, since it may yield less revenue than the government mandated feed-in tariff. This is an empirical question, not a fundamental conflict.

Moreover, a key goal of GP contracts would be to provide a more secure "convergence point" for technologies if and as technology-specific supports phase down. At present, the proposition appears to be that low carbon technologies will benefit from an extended period of support, whilst there is an 'industry-building' case for supporting the implicit innovation, or compensating for an inadequate carbon price – but will then have to fend for themselves on the basis of a market determined entirely by short-run marginal prices of fossil fuels and carbon. As explained above, this is a recipe either for windfall profits or eternal financial restructuring of bankrupt projects that cannot cover their capital.

GP contracts could offer a much more robust answer to the question of whether and how Europe could ultimately move beyond current technology-specific supports. As emphasises, the carbon price would still be crucial – but alongside it, there would be a market structure more appropriate for supporting continued investment in low carbon technologies.

10. Conclusions

The creation of a low-carbon power system is a crucial cornerstone of the move towards a low-carbon economy. This requires large scale investment and innovation. Our current electricity market structures have incentivised little innovation and R&D, and create large uncertainties for investors. We have put in place policy instruments to try and address these problems. Feed-in-tariffs and renewable obligation certificate schemes attempt to create greater certainty over returns to investment, and boost demand for renewable power. Both of these policies have had their successes and failures.

Technology-specific policies have been in addition to carbon pricing that is at the heart of climate change policy in the EU. Carbon pricing affects electricity greatly. Its introduction in the EU has incentivised coal-gas switching, and efficiency improvements, but also brought windfall profits for generators who received allowances for free.

Relying on carbon pricing alone can have side effects that are difficult to handle. If the cost impact on key industrial sectors is sufficiently high and cannot be passed through to consumers, industries may move abroad with their emissions and jobs. Although electricity is not directly at risk, electricity-intensive industries like aluminium may be. Free allocation has been the main policy instrument used so far to tackle leakage, but is not directly applicable to electricity-intensive consuming industries, and brings its own problems. Border levelling offers a potential solution, but accounting for the carbon in electricity is extremely problematic under current market structures.

Harnessing consumer and but perhaps more importantly business and industry demand for renewable electricity can help raise investment in low-carbon power, and also increase the political acceptability of the endeavour. Our current market structures struggle to harness this demand, and the systems we currently have in place struggle to provide clearly additional renewable power.

Creating a clearly defined separate low-carbon electricity product could help to harness this demand. It could also help to create greater product differentiation in the electricity market, forming market niches that could foster learning and innovation. A separate contractual structure for low-carbon electricity could help reduce uncertainty for investors, by allowing pricing to be more structured according to the capital-cost intensive nature of low-carbon generation. It could also help to provide a basis for border-levelling to address leakage concerns of electricity-intensive industries, and provide incentives for investment in low-carbon electricity in countries that export into the EU.

Further research is required as to the feasibility and steps required to create such a low-carbon electricity product, although lessons can be learnt both from the green tariff markets, and the few cases of industrial long-term contracts, that exist today. Proving additionality and attributability are crucial parts of the challenge. Whether and how to create a separate contractual market that allows competition between low-carbon electricity and the rest of the system requires more research and analysis.

This paper has spelt out the concept of a separate low-carbon electricity product, and some of the benefits may bring, if it can be viably created. What is clear is that the electricity system of the future will look very different from the structure we have today, and change is inevitable.

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Table 2: Green Energy tariffs in the UK (Source: Green Energy Supply Certification Scheme, Company *websites)*

Supplier	Tariff	Green Energy Scheme Certified	Percentage of renewables in generation mix	CO_2 g per Kwh	Retirements	Other environmental benefits
British Gas	Future Energy	Yes	6.6	374	None	Premium paid into the non-profit British Gas Green fund to support schools in Great Britain reduce CO2 emissions, and into the research and development of new environmental projects.
	Future Energy Plus	Yes	6.6	374	Retire ROCs of 12% of electricity supplied	Premium used to fund an offset for the CO2 emissions related to the gas and electricity supplied and paid into the non-profit British Gas Green fund to support schools in Great Britain reduce CO2 emissions, and into the research and development of new environmental projects.
EON	Go Green	Yes	0.3	360		1.8 tonnes of carbon dioxide offset through Climate Care for every customer per year.
EDF	Green Tariff	Yes	6.9	567		Funds small-scale renewable projects that save 50kg CO_2e per customer
Good Energy	Good Energy	Yes	100	0	The financial equivalent of an additional 0.05 ROCs per MWh	50kgCO_2e of abatement funding renewable heat projects.
Npower	Juice	Yes	5	543		£10/person to the Juice Fund a year that is used to support community based renewable generation projects.
Scottish Power	Simply Green	Yes	6.9	570		£10.50 (incl. VAT) to the Green Energy Trust each year, an independent charity that supports renewable energy projects in the UK.
Scottish Hydro, SWALEC and Southern Electric	Betterplan plus	Yes	9.7	413		Financial incentives in place for energy reduction efforts.
Ecotricity	New Energy	No	45.6	232.4		100% of electricity bill spent on building new sources of green energy
	New Energy Plus	No	100	232.4		100% of electricity bill spent on building new sources of green energy
Green Energy	Deep Green	No	100	0		
	Pale Green	No	100	157		