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Policies for decarbonizing a liberalized power sector

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Keywords carbon price, electricity, investment, renewables, marginal abatement cost

JEL Classification C65, Q42, Q48, Q51, Q54

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Policies for decarbonizing a liberalized power sector

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Abstract

Given the agreed urgency of decarbonizing electricity and the need to guide decentralized private decisions, an adequate and credible carbon price appears essential. The paper defines and quantifies the useful concept of the break-even carbon price for mature zero-carbon electricity investments. It appears an attractive alternative given the difficulty of measuring the social cost of carbon, but modelling shows it extremely sensitive to projected fuel prices, the rate of interest, and the capital cost of generation options, all of which are very uncertain. This has important implications, and justifies combining a carbon price floor with suitable long-term contracts for electricity investments. The same sensitivity demonstrated for the break-even carbon price translates into similar sensitivities for marginal abatement cost curves.

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1 Introduction

It is widely accepted that an efficient climate change mitigation strategy requires the rapid decarbonization of the power sector (IEA, 2012, 2015; CCC, 2009, 2014). Power sectors in most advanced economies have competitive privately-owned generation companies trading

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on wholesale fuel and electricity markets, unbundled from transmission, distribution and retailing. As such they take short-run operating decisions on the basis of spot fuel and carbon prices and make commercial investment decisions on the basis of forecast fuel and electricity prices (e.g. DECC, 2014) or computed using simulation models, such as the DECC Dynamic Dispatch Model (DECC, 2012), given announced taxes and subsidies and a view about the future time path of CO_2 prices.

The UK Government (DECC, 2009) with most other European countries and the European Commission (EC, 2015) recognize and intend to address the energy policy trilemma: to deliver reliability, sustainability (decarbonization) and affordability/competitiveness. Of these three, the hardest question is how best to incentivise the decarbonization of the power sector. There is considerable dispute as to whether renewables targets, e.g. as specified in the EC *Renewables Directive* (EC, 2009), a carbon price, emissions performance standards (EPS) of the kind introduced in the UK in the *Energy Act 2013* (HC, 2013), or some mix of these policies, possibly embodied in long-term contracts, would be most cost-effective.

Setting a carbon price would seem the natural approach for a liberalized power sector, as standards are typically criticized for failing to equilibrate marginal damage costs across sectors or technologies. For setting the carbon price to be effective in delivering the objective of rapid decarbonization of the electricity sector, its resulting value should not be too sensitive to fuel price and other uncertainties. Unfortunately, this is not the case, as this paper demonstrates, which strengthens the case for supplementary policies. This paper introduces the concept of a break-even carbon price - the carbon price at which a zero or low-carbon technology (e.g. an on-shore wind turbine) has the same cost as a competing more carbon-intensive alternative (e.g. a combined cycle gas turbine, CCGT) and develops a methodology to explore the sensitivity of this carbon price to key uncertain parameters, such as future fossil fuel prices, the discount rate and capital costs.

This methodology can be readily applied to a wide range of technology comparisons, here illustrated with on-shore wind competing with a CCGT, a nuclear plant competing with an advanced combustion coal plant, and the short-run fuel switching between existing coal and gas plant. The results are dramatic. Given the predicted range of gas prices in the near future, the uncertainty about the level of carbon price needed to support on-shore wind is at least £95/tonne CO_2 (€120, US\$140), or from £35-130/t. CO_2. The range of carbon prices needed to induce a large short-run switch from coal to gas in Britain (the results are country and generating stock specific) might be from £5-65/t. CO_2. Such a wide range for the "right" carbon price also throws some doubt on the wider discussion of whether taxes, quotas or hybrid instruments are best suited to guide CO_2 emissions reductions policies.

Much of the literature that models policies to reduce emissions is somewhat abstract, usually examining a single technology whose emissions can be affected by investment or current expenditures, possibly interacting with an uncovered or foreign sector (Mandell, 2008; Holland, 2012), or as a coordination game with other regions to overcome commitment problems (Wirl, 2012), or exploring the "double dividend" of reducing distortionary taxation elsewhere (Jotzo & Pezzey, 2007; Goulder, 1995). The approach taken here is far more specific, and examines a liberalized electricity supply industry (ESI), which has important characteristics that require a taylored approach to designing emissions and related policies. An efficient energy and climate change suite of policies needs to ensure efficient operation of existing capacity, efficient choices of new capacity, as well as ensuring efficient demand responses, including energy efficiency. Climate change mitigation also needs an efficient innovation support policy, but that requires additional and complementary policies.

The next section reviews arguments for setting a carbon price rather than a quota, then considers the practical problem of setting a carbon price by parameterizing a simple model for the break-even carbon price in the ESI. Section 3 develops the model. Section 4 shows how the same approach can be applied to determining Marginal Abatement Cost (MAC) Curves, widely popularised by McKinsey as ways to screen for attractive decarbonizing options. Section 5 addresses the problem of designing suitable decarbonization policies for the ESI and section 6 concludes.

2 Carbon taxes, carbon caps and credibility

A carbon price can be either delivered by fixing a quota or quantity (the cap) and then trading, as in the EU Emissions Trading System (ETS) (2003/87/EC), or fixing the price through some form of carbon tax or charge, such as the Carbon Price Support introduced in the 2011 UK Budget (HMT, 2011). The classic argument for setting a carbon price is based on Weitzman (1974), who noted that in the face of uncertainty, a price instrument (tax or charge) dominates a quantity instrument (a cap or quota) if the marginal benefit of reducing emissions is flatter than the marginal abatement cost schedule. The marginal damage of a tonne of CO_2 now is essentially the same as a tonne emitted in 10 years' time, as CO_2 is resident in the atmosphere and oceans for a century or more. Thus the marginal benefit of abatement is essentially flat in the *rate* of emissions, even if the marginal damage is steeply increasing in the *stock* of emissions (Grubb & Newbery, 2008).

Weitzman's original result was derived from a static model with uncertainty resolved immediately after abatement choices, and so only suitable for flow, not stock pollutants. It may be suitable for short-run operating decisions of existing capacity (whether to run coal or gas-fired plant more intensively), but is not well-suited to investment decisions in highly durable capacity. Nuclear and coal power stations have a life of 60+ years, even if gas-fired plant and wind turbines have shorter (20+) year lives, periods that commit to significant lock-in of cumulative emissions and hence a lock-in to a higher and more damaging stock of greenhouse gases (GHGs). IEA (2012) showed that 83% of 2020 target emissions to reach the 2^o C trajectory were already locked in through existing infrastructure, while IEA (2015) showed that subsequent emissions have increased, further reinforcing existing lock-in and squeezing the remaining room for manoeuvre.

To deal with these lock-in and stock effects, one needs an intertemporal model in which damage depends on the stock of pollutant, not the flow. Pizer (2002) considered a modified DICE model (Nordhaus, 1994) in which the price or quantity is set in the base year. With his base calibration, the benefits of setting the optimal price are five times as large as those of setting the optimal quota. If the damage costs rise sufficiently rapidly with rising temperatures, then quotas become more attractive over a 50-year horizon. Such open-loop models in which agents fail to take account of future policy changes are unsatisfactory. As time passes we learn more about the likely future consequences of any stock of GHG, and hence the shape and level of the marginal damage (marginal abatement benefit) schedule. We also learn more about the costs of abatement and adaptation and need to adjust policies in light of this new information. While this simplification is understandable given the complexity of closed-loop models, sensible policy will respond to new information and this needs to be taken into account.

Hoel and Karp (2002) do this using feed-back optimal control in an intertemporal stochastic stock pollution model. Cost shocks are serially uncorrelated, the policy maker can periodically adjust policies in light of their development and investors take this into account when choosing their plans. Under parameter values that are plausible for GHG stocks and climate change, price policies are superior to quantity policies, confirming the one-period Weitzman intuition. Karp and Zhang (2006) allow for anticipated learning about future climate change damage and show that such learning favours the use of taxes rather than quotas. Subsequent more sophisticated dynamic models also tend to support this finding. Karp and Zhang (2012) point out that if, reasonably, investors have better cost information than policy makers, carbon taxes are potentially time-inconsistent while quotas are not in the face of cost shocks. Nevertheless, they find that in their linear-quadratic model with plausible parameters, taxes are still welfare superior to quotas. This does highlight a credibility problem with taxes, relevant to the policy choices considered below.

An efficient path to a low-carbon future must also deliver adequate Research, Development, Demonstration and Deployment (RDD&D) as part of an Energy Technology Innovation System (Gallagher, et al. 2012) that requires carefully designed policies (Mercure et al., 2014; Jamasb & Pollitt, 2015; Bointner, 2014; Popp & Newell, 2012; Soriano et al., 2011). A high carbon price will make such RDD&D more attractive but will fall short of capturing the full social benefit of innovation and so additional support is warranted, particularly as patent protection may limit the desired deployment to developing countries. The same case for additional support applies to still maturing renewables where learning-by-doing creates beneficial spillovers not captured by developers, but which accelerate decarbonization elsewhere (Slechten, 2011; Weyant, 2011; Newbery, 2012). Recognizing that these beneficial externalities justify additional support policies, the question remains whether a single instrument such as a carbon price will suffice to adequately mitigate CO_2 emissions in the power sector for mature low-carbon technologies.

A large part of the case for demonstration and deployment support derives from the learning benefits they can deliver, and the information they reveal about the potential for future improvement. There is a related literature on whether learning is an argument for delay until we know more about damages (Karp and Zhang, 2006, and the extensive literature cited), whether this result is robust to irreversibilities (Chichilniski and Heal, 1993), or conversely, as much of the learning is learning-by-doing that affects abatement costs, whether the opposite is the case and investments should be advanced (Slechten, 2011). Athanassoglou & Xepapadeas (2012) show that an increase in Knightian uncertainty when choosing the least worst regrets option leads under plausible parameter values to an increase in precautionary policy.

Even if a predictable and credible carbon price is desirable for guiding investment decisions, it has proven politically much easier to introduce a cap-and-trade system with a free allocation of permits to those who would otherwise be adversely affected and have sufficient political clout to prevent an otherwise widely accepted decision to reduce emissions. There is a separate and important issue about whether it is easier to agree an international climate change agreement by coordinating on a carbon price, as Weitzman (2015), Stiglitz (2015) and Cramton et al. (2015b) argue, or whether an international cap-and-trade agreement is preferable, as Gollier and Tirole (2015) claim. If cap-and-trade agreements are the likely starting point, hybrid schemes that combine elements of price and quantity schemes become attractive (Roberts and Spence, 1976; Weitzman, 1978). Hybrid schemes allocate permits and then keep the price that emerges from trading these permits within bounds by auctioning permits above a trigger price and setting a floor price.[1] The desirable goal of price predictability, which reduces risk and hence cost, can also be fostered by allowing banking and borrowing of permits, which also support a carbon price rising at the rate of interest, as required. Weber and Neuhoff (2010) consider the incentive effects of different policies on innovation incentives and find they can increase the relative attraction of quantity compared to price-based schemes. The logical conclusion is that if there are learning externalities, these should be addressed with an additional targeted policy instrument.

Setting price bounds can reduce the uncertainty about auction revenues and reduce fiscal risk, which was certainly a motive for the UK Treasury imposing a Levy Control Framework to limit budgetary support to renewables in its *Electricity Act 2013.* Similarly, defending the upper bound may lead to excessive emissions, again arguing for a limit. Fell et al. (2012) consider such collars, and argue that a limited soft collar can mitigate most of the risk – an argument familiar from the early price stabilization literature (Newbery & Stiglitz, 1981; 1982).

Finally, an emissions performance standard, EPS, has been proposed either as a supplement or an alternative (Holland, 2012; Fischer & Springborn, 2011). That may be a more robust single instrument at the national level in the face of macro-economic uncertainty, or at the sector level as a back-stop, the reason for the EPS in the UK *Electricity Act 2013.* Nevertheless, most of the arguments for choosing quantity instruments or hybrids are either (understandable) political arguments, or a recognition that with multiple

[1] Weber and Neuhoff (2010) point out a number of disadvantages of hybrid schemes, including the difficulty of coordination across regions.

objectives (e.g. innovation as well as decarbonization) or multiple future states of the world, more than one instrument is likely desirable. They do not argue against the desirability of delivering a predictable and credible time path of carbon prices to guide private investment decisions in mature technologies.

The issue of policy credibility is clearly critical when investment decisions are made by private actors, and here neither quotas nor taxes alone score well. The UK Government enacted a Carbon Price Support in the Budget of 2011 as a tax on carbon embodied in fuel used by the electricity sector (HMT, 2011). This was intended to bring the effective carbon price up from that set in the EU Emissions Trading System (ETS) to a pre-determined Carbon Price Floor, set to reach £30/tonne carbon dioxide (CO_2) by 2020 and £70/t CO_2 by 2030. Almost immediately, however, the floor price was frozen at its early low level in the 2014 Budget, demonstrating the lack of credibility of a tax subject to annual budget making.

The quotas for the EU ETS are periodically re-set and the ETS has witnessed highly volatile prices, even in the later periods that allowed banking. From a high of €30/EUA (1 EUA =1 t CO_2) in 2008 the price has since fallen to €5-8, making unsubsidized low-carbon generation investments commercially unattractive. As the cap has to be periodically renegotiated between 28 Member States, and as there are pressures both to prevent its collapse but also to prevent it reaching levels that make the traded sector uncompetitive, it is difficult to have confidence in future quotas and resulting carbon prices. For durable capital decisions, such as generation investment, the logical solution to the credibility problem is a long-term contract, considered below.

To summarise the literature on the choice of instruments, investor credibility requires long-term contracts (either, in the ESI, on the carbon price, the electricity price or to capacity payments), while Weitzman's original (1974) argument for taxes/prices rather than quotas for GHG emissions is less clear-cut in a multi-period world with massive future fossil fuel price uncertainty. At least in the ESI, the test of any instrument is its ability to induce financiers to view mature low-carbon generation investments as low risk and hence low (finance) cost options. One possibly unpalatable implication is that the best instrument and implied carbon price for one sector, such as the ESI, may not be the best for another sector (transport, construction, heating, etc.) and that the cost of differing shadow carbon prices co-existing may be offset by the benefits of reducing investment costs by enhancing credibility and future revenue certainty. In a world of missing markets, the simple solutions of uniform corrective prices may no longer apply (Newbery, 2016; Newbery and Stiglitz, 1982).

2.1 Setting a carbon price

Setting a predictable carbon price trajectory or a carbon tax is, however, problematic, as would be setting the floor and ceiling for price collars. The social cost of carbon (SCC), explained in Stern (2006) and widely used by agencies such as the US EPA[2] "to estimate the climate benefits of rulemakings" is difficult to estimate with any precision, as it involves computing the future damage imposed by the current emission of 1 tonne of CO_2 and discounting it back to the present. The social cost of the damage is problematic as it involves weighting disparate levels of future consumption, as is the discount rate, which should depend on the state of the future world in which the damage is incurred (Stern, 2006; Weitzman & Gollier, 2010). For example, Ackerman and Stanton (2012) find that the 2010 SCC could range from \$21/tCO_2 to \$800/tCO_2.

While the SCC may be an attractive way of framing the global public good problem of climate change, any international negotiation is likely to need a more solidly founded basis on which to coordinate an international carbon price, given the arguments summarized by Cramton et al. (2015a). Given the agreement that the price must be at least sufficient to make decarbonizing the electricity supply industry (ESI) rational, one natural choice would be the price needed to make mature zero-carbon generation commercially viable, since the carbon targets cannot be met without an almost complete and early decarbonization of the ESI. The next section demonstrates that the break-even carbon price is highly sensitive to fossil fuel prices, discount rates and capital costs, all of which are uncertain, making it difficult to set a suitable carbon price to guide generation investments, or to judge whether the price delivered by a cap-and-trade system is suitable. It is important to recognise the significance of this claim, as it is no surprise that choices may depend on assumptions, which are often uncertain. The problem is not that there is a sensitivity, but that the resulting range of possible break-even carbon prices dwarfs almost everything else, and far exceeds the range of prices thrown up by the ETS. Complaints that some intervention is only justified at a very high carbon price,which might normally be interpreted as evidence of a very inefficient policy, may no longer be justified if the fuel price (and some other)

[2] see http://www.epa.gov/climatechange/EPAactivities/economics/scc.html

uncertainties are recognised as having extremely wide error bars.

Cullen and Mansur (2014) also point to the sensitivity of the carbon price needed to stimulate a fuel switch between existing power stations in the US to the price of gas, noting that recent falls in the price of gas have reduced the required carbon price to achieve a reduction in ESI carbon emissions. While they do not address the long-run investment question that is the prime focus here, their finding is consistent with the discussion of short run MAC curves in section 4. Newbery (2008) developed a similar model of fuel switching between existing generating plant but primarily directed to its impact on market power in the gas market, not to the implications for carbon pricing.

2.2 Marginal Abatement Cost Curves

Marginal Abatement Cost Curves (MACCs) have been popularized, particularly by McKinsey (2007), as a graphic tool for demonstrating the potential and cost of reducing levels of pollution such as GHG. MACCs have been criticized (e.g. in the paper by Ekins et al., 2011, which discusses their sensitivity to various cost parameters in depth). The idea behind the MACC is simple and appealing: in a given economy at some date, how much abatement of CO_2 can be delivered at least cost for each carbon price (e.g. \$(2005) per tonne CO_{2e}). Thus McKinsey (2007, exhibit A) shows various MAC schedules for the US in 2030, which they footnote as depending on "techno-engineering costs.". In their update after the financial crisis McKinsey (2010) notes the changes in the MAC curve are linked to changes in fuel prices (among other factors), as oil prices had increased dramatically since 2007 – the IEA WEO 2009 increased oil prices to \$115/bbl (which, by early 2016 had fallen to \$35/bbl). The updated report noted, however, that its main messages remained unchanged.

The concept can also be applied to sectors such as the ESI, and that makes it simpler to see what is involved (and the McKinsey report argues that the investments needed to deliver GHG reductions are highly concentrated in the power and transport sectors). The techniques developed below to test the sensitivity of carbon prices needed to guide investment decisions can similarly be applied to the long-run MACC for the ESI, and with simplifications, to the short-run MACC. These extensions to deriving MACC sensitivities are presented in section 4.

3 The model

There are two reasons for using a carbon price in the ESI – in the short run to deliver an efficient merit order (the set of plant operating and their output levels) from the existing portfolio (discussed in section 4.1 in connection with the short-run MACC), and, the main subject of this paper, to guide investment choices. At the final investment decision date for zero-carbon plant, it must be more profitable than fossil-fueled alternatives, which requires a carbon price above the break-even price – the carbon price needed to make zero-carbon and fossil generation investments equally profitable. The break-even carbon price depends on the carbon intensity of the fuel, γ, (t CO_2/MWh_{th}).[3] If zero-carbon generation is competitive at a fossil fuel price f and a CO_2 price of c (£/t CO_2), then a £1/MWh_{th} fall in the price of fuel would require an offsetting $1/\gamma$ increase in the price of CO_2 to maintain cost parity between zero-carbon and fossil generation.

The likely future competitive fuel in the ESI is gas. For delivered pipeline gas $\gamma = 0.19$ tonnes CO_2/MWh_{th}, so the multiplier for the CO_2 price is 5.24. This makes the break-even carbon price very sensitive to the gas price. This might not matter if the gas price were predictable and stable. Unfortunately, this is not the case as its price uncertainty is large, as shown in Fig. 1. The range between the UK's low and high wholesale gas price scenarios for 2017 made at the end of 2015 (DECC, 2015b) is from £12.3/MWh_{th} to £23.4 MWh_{th}, or £11.1/MWh_{th}.[4]

The range in UK projected 2020 gas prices is £15.7/MWh_{th} with an implied range in the required break-even CO_2 price of £82/tonne, which is more than 100% of the original UK 2030 (supported) carbon price (DECC, 2010). In contrast, for coal, $\gamma = 0.341$, the multiplier is only 2.93 and the range of UK forecasted coal prices in 2020 is only £3/MWh_{th} (although since 2000 the actual range has been £(2015)6.20/MWh_{th}). If coal were the competitive fuel, the uncertainty in the carbon price would be only £8.8/tonne (or £18/tonne using the historic range).

[3] The subscript $_{th}$ refers to the thermal energy content of the fuel, unsubscripted MWh refer to electricity output.

[4] DECC publishes wholesale fuel price forecasts (for gas at the trading hub, for coal cif ARA in \$/tonne. The figures are adjusted to include the observed past margin into power stations, from https://www.gov.uk/government/statistical-data-sets/prices-of-fuels-purchased-by-major-power-producers

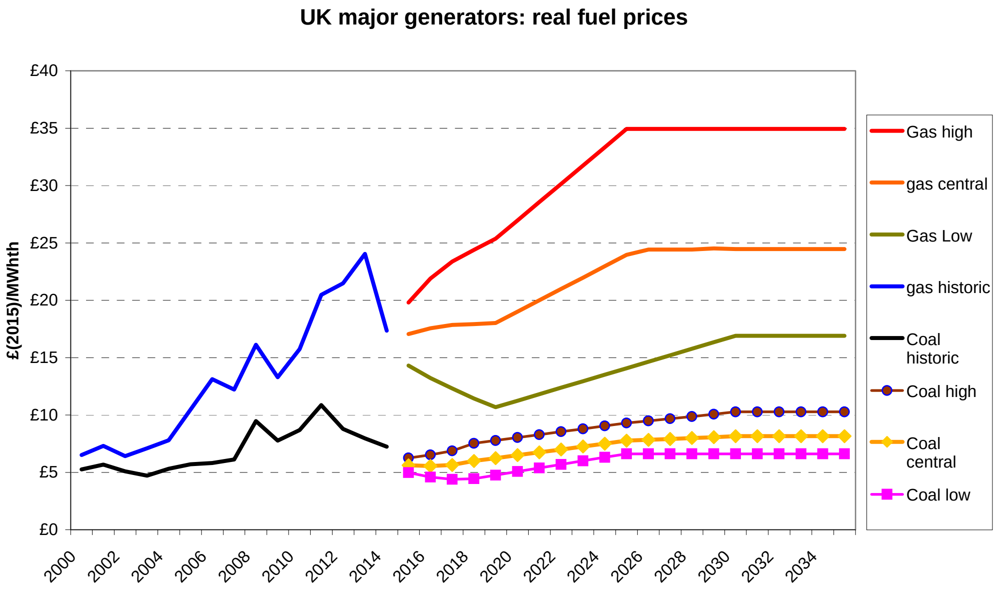

Figure 1: UK fuel prices past and future scenarios (DECC, 2015b)

3.1 Sensitivity to parameters

Fossil generation and zero-carbon generation (wind, PV, nuclear power, etc.) differ in their cost and operating characteristics in important ways, which for present purposes it is convenient to measure by levelised costs. To be clear on the meaning of levelised cost, as an example consider levelising the price. If p_{ht} is the wholesale price in hour h of year t, then if the time horizon is T and the discount rate is r, the levelised price p is defined first in terms of the base-load (time-weighted) price for that year, p_t, and then over the time horizon as the constant price giving the same present value as the actual stream of prices:

$$p\int_0^T e^{-rt}dt = \int_0^T p_t e^{-rt}dt, \quad p_t \equiv \sum_{h=1}^{Y} \frac{p_{ht}}{Y}, \quad Y = 8760.$$

Suppose that the relevant lives of the most attractive fossil plant and zero-carbon plant are the same (e.g. CCGT and on-shore wind) at T, and denote the fuel type by subscripts (e.g. $i = w$ for wind, g for gas). K_w and K_g are respectively the capital cost in £/MW capacity of wind and gas, M_i are the fixed O&M costs, £/MWh, (measured for convenience per hour, averaged over each of the $Y = 8760$ hours of the year), v_i are the variable O&M costs in £/MWh, f_t is the fuel cost in £/MWh$_{th}$, c_t is the carbon cost in £/tonne CO_2, e_i is the efficiency of the fossil generator (MWh/MWh$_{th}$), B_i are the capacity factors (e.g. for wind, the average fraction of equivalent full output hours per year, assumed constant for any specific wind farm). It is convenient to define two other parameters, $H \equiv 1/e$ is the heat rate, in $\mathrm{MWh}_{th}/\mathrm{MWh}_e$. $\phi \equiv \gamma H$ is the carbon intensity of the electricity generated from the fossil fuel.

The gross profits per unit capacity in year t are π_{it}:

$$\begin{aligned}
\pi_{wt} &= \sum_h q_{wht}(p_{ht} - V_w) - M_w Y = B_w Y(\theta_{wt} p_t - v_w) - M_w Y, \\
\theta_{wt} &\equiv \frac{\sum_h q_{wht} p_{ht}}{B_w Y p_t}, \quad \text{where } q_{wht} \text{ is wind output in hour } h. \\
\pi_{gt} &= \sum_h \max(p_{ht} - v_g - H f_t - \phi c_t, 0) - M_g Y, \\
\pi_{gt} &= B_{gt} Y(\theta_{gt} p_t - v_g - H f_t - \phi c_t) - M_g Y.
\end{aligned}$$

Here q_{wht} is the output per MW capacity in hour h and year t of the zero-carbon plant (wind) and θ_{it} measures the ratio of the average revenue per MWh earned by technology $i = w, g$ and the base load (time-weighted) average price in that year (termed the *value factor* by Hirth, 2013). Thus in Britain, wind output is positively correlated with price at low levels of wind penetration, so $\theta_w > 1$, but as wind penetration increases, it becomes more dominant in hours of high wind and depresses the price, eventually causing $\theta_w < 1$ (Green & Vasilakos, 2010). For the fossil (gas) plant, B_{gt} is the fraction of the time that the spot price is above the avoidable cost, equal to its capacity factor (CF), while $\theta_{gt} > 1$ is its *value factor* for fossil plant as positive fuel costs mean that plant will not supply when the price falls below variable operating costs and will therefore supply in the higher-priced hours. Both b_t and ϕ_t are influenced by low-carbon penetration, with b_t falling but ϕ_t rising as zero-carbon low variable cost plant sets low prices in an increasing number of hours. For a given fossil plant technology, their product will fall over time as this type of plant becomes less profitable.

The annualization factor to convert the capital cost into an hourly cost is $\xi \equiv r/(Y(1- e^{-rT}))$. The break-even levelised carbon price, c, equates the profitability of the competing technologies:

$$\pi_w = B_w(\theta_w p - v_w) - (M_w + K_w \xi) = \pi_g = B_g(\theta_g p - v_g - H(f + \gamma c)) - (M_g + K_g \xi). \quad (1)$$

Here f is the levelised forecast fuel price, B_i, θ_i, and π_i are the levelised forecast values of the CF, value factors, and net (annual) profits. If the carbon price c is adjusted to remain at the break-even level and each technology (fossil and zero-carbon) is the most profitable currently available, then in competitive equilibrium, the price p adjusts to make both (excess) net profits zero. Set (1) to zero and eliminate p to give the levelised break-even carbon price:

$$H\gamma c = \frac{\theta_g}{\theta_w}(\frac{M_w + \xi K_w}{B_w} + v_w) - (\frac{M_g + \xi K_g}{B_g} + v_g) - Hf. \tag{2}$$

Partially differentiating (2) confirms that $\partial c/\partial f = -1/\gamma$, except that the fuel and carbon prices are now their levelised values. The break-even carbon price rises with efficiency, e, of the marginal entrant fossil plant and with the fixed and variable excess cost of the zero-carbon plant over the fossil plant (suitably adjusted for price and capacity factors). Similarly, $\partial c/\partial v_g = -1/\phi$ and $\partial c/\partial v_w = \theta_g/(\theta_w \phi)$, both smaller in absolute size than $\partial c/\partial f$ with θ_g/θ_w normally >1 for wind.

If $A_i \equiv M_i + \xi K_i$, are the total fixed and capital costs per MWh, then $\partial c/\partial A_i = B_i^{-1}\partial c/\partial v_i$, $i = w, g$. For fossil plant all these parameters are fixed except for B_g, which will be lower the higher is the capacity share of zero-carbon plant relative to the higher variable cost fossil plant. For wind turbines, B_w may be fixed but the relative value factor θ_g/θ_w is likely to rise over time with increased penetration. Over time the value of e/γ will fall as cheaper but less efficient peaking plant is increasingly installed in place of baseload fossil plant, given the lower value of b, so the carbon price will become less sensitive to excess fixed costs, and as γ rises, so the sensitivity of the carbon price to fuel prices will fall. Thus the sensitivity of the carbon price falls over time with decarbonization.

If we ignore the (lower) dependency of the levelised fuel and carbon costs on the rate of discount, and concentrate instead on the more sensitive amortization factor, ξ, holding everything else constant, then

$$\frac{r\partial c}{\partial r} = \frac{\xi}{\phi}(\frac{\phi K_w}{\theta_w B_w} - \frac{K_g}{B_g})\frac{d\xi}{dr} = \frac{\xi}{\phi}(\frac{\theta_g K_w}{\theta_w B_w} - \frac{K_g}{B_g})(1 - \frac{rTe^{-rT}}{(1-e^{-rT}}). \tag{3}$$

To gain an order of magnitude of the carbon price sensitivities, Table 1 provides cost and technology estimates and Table 2 gives the levelised fuel prices. These data can be used to compute the equilibrium levelised carbon and time-weighted electricity prices for either on-shore wind and a gas-fired combined cycle gas turbine (CCGT) or for base-loaded nuclear power and Advanced Supercritical Coal (ASC) with flue gas desulphurisation. At these equilibrium prices the various sensitivities can be calculated, assuming for present purposes an interest rate of 5% (real) and the central values in Table 1, with the High gas price discounted over 20 years but the Medium coal price discounted over 40 years.

Table 1 Cost and technology parameters

units	symbol	on-shore wind	CCGT	Nuclear	ASC Coal
£/MW/8760	K_i	183 $\pm$50	70 ± 12	580 ± 145	190 ± 20
£/MW/8760	M_i	3 ± 1.5	2.7 ± 0.6	10 ± 2	5 ± 1
£/MWh	v_i	4 ± 1	1.6 ± 0.4	2 ± 1	2 ± 1
Lifetime yrs	T	20 ± 5	25 ± 5	60	50 ± 10
Capacity factor	B_i	$25\% \pm 3\%$	$40\% \pm 10\%$	$90\% \pm 2\%$	$88\% \pm 2\%$
HHV %	e		$53\% \pm 1\%$		$41\% \pm 2\%$
t. CO_2/MWh$_{th}$	γ	0	0.19	0	0.341
price factor	θ_i	1 ± 0.1	1.2 ± 0.1	1	1.1

Source: DECC (2013), NREL (2010)

Table 2 levelised fuel prices for varying time horizons and discount rates

$r,\ T$	Gas H	Gas L
5%, 20yrs	£32.6	£15.0
10%, 20yrs	£31.7	£15.1
5%, 25 yrs	£33.0	£15.0
	Coal H	Coal M
5%, 40 yrs	£15.4	£12.3
10%, 40 yrs	£8.3	£6.8
5%, 60 yrs	£17.2	£13.6

Source: DECC (2014)

Table 3 shows in the column headed "Multipliers, m" the values of the $m$ultipliers $\partial c/\partial x$, where x is variously f, v_i, A_i, etc., except in this case $==n, f$, for $n$on-fossil or $f$ossil technology, estimated at equilibrium values of c, the full range of uncertainty of each of the parameters, Δx, from Tables 1 and 2, and the resulting change in c, Δc, from multiplying the multiplier with the range.

Table 3 Sensitivities and impacts on the break-even carbon price

	Multipliers, m	Range	Response	Multipliers, m	Range	Response
	gas v. wind	Δx	Δc	Coal v. Nuc.	Δx	Δc
$\partial c/\partial f$	-5.3	£17.6	-£93	-2.9	£6.6	-£19
$\partial c/\partial v_f$	-2.8	£0.8	-£2	-1.2	£2	-£2
$\partial c/\partial v_n$	2.3	£2	£5	1.2	£2	£2
$\partial c/\partial A_f$	-7	£3	-£21	-1.3	£3	-£4
$\partial c/\partial A_n$	9.2	£11	£100	1.4	£20	£28
$r\partial c/\partial r$	35	5%	£35	31	5%	£31

Source: Tables 1, 2

Fig. 2 illustrates this sensitivity graphically comparing gas CCGT with on-shore wind. As the price of gas rises along the x-axis, for any set of other parameters the break-even price of CO_2 falls (the break-even lines slope down). As the interest rate rises for any gas price the lines move vertically up and with them the required break-even CO_2 price, while as the capital cost of CCGT rises relative to the wind turbine, so the lines move down, as does the break-even CO_2 price.

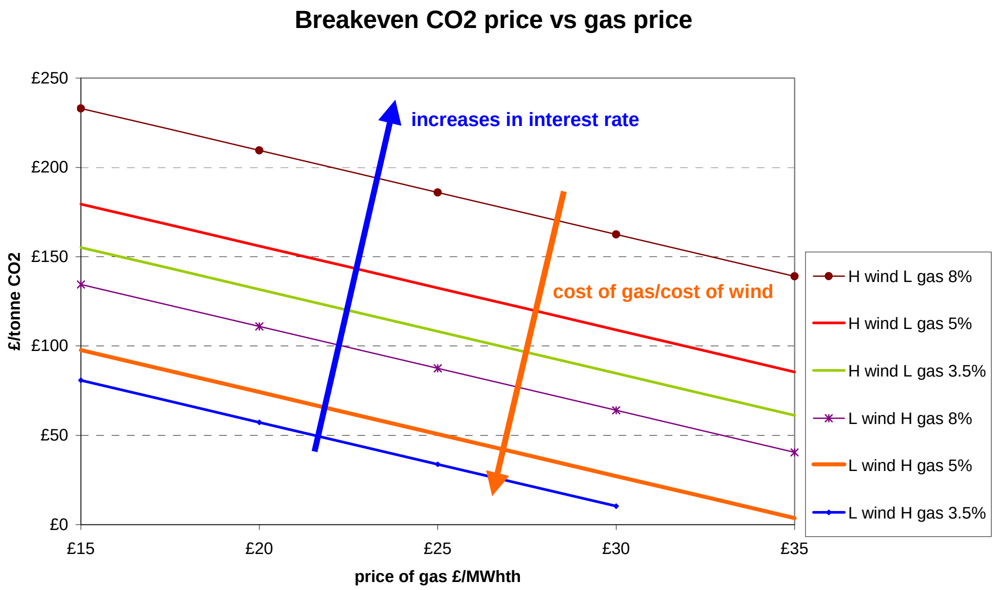

Figure 2: Break-even CO_2 prices vs. the gas price

In Table 3, if the gas price were Low instead of High, c would have to increase by

$\Delta c = m.\Delta x = -5.3 \times -\pounds 17.6 = \pounds 93$/tonne CO_2, and if the total fixed cost per MW of wind, A_w, were to rise by £11/hr, c would need to rise by £100/t. In contrast if nuclear and ASC coal are both the marginal technologies, the sensitivities are far lower and even a change in the total fixed cost per hour per MW of nuclear, A_n, were to rise by £20/hr, c would need to rise by only £28/t (at these perhaps optimistic values for the capital cost of nuclear stations). Similarly if the rate of interest were to rise from 5% to 10% (i.e. doubling) c would need to increase by £35/t (wind) or £31/t (nuclear) as the zero-carbon options are more capital intensive and so more impacted by a rise in the WACC, r.

3.2 Other applications and implications

The range of possible low-carbon generation options is wider than just on-shore wind and nuclear power, and includes solar PV, off-shore wind, biomass, and carbon capture and storage (CCS), applied either pre- or post-combustion to coal or CCGTs. Some, such as biomass and arguably CCS, are mature (at least in their component parts) and for these the same method can be applied to compare any of these with the least-cost fossil option. Others are less mature and investments deliver a learning benefit of uncertain but potentially important value. This can be treated as a credit to the investment (almost all learning is delivered in the supply chain up to the point of commissioning, although some may derive from its operation), and can thus be considered as an uncertainty about the *attributable* capital cost (i.e. the gross cost *less* the learning benefit). A more sophisticated extension would recognize that the optimal decarbonization strategy is likely to require a portfolio of technologies, as their performance will be imperfectly correlated with uncertain parameters (fossil fuel prices, discount rates, capital costs). At each combination of generation plant on the efficient risk-reward frontier, there is a weighted average response of the break-even carbon price allowing for these cross correlations (Roques et al., 2008).

It is also quite standard to compute the implied cost of saving a tonne of CO_2 when examining various policy options such as improving building insulation standards, some of which are directly observed on auction markets, such as that for ECO.[5] In some cases the numbers are given with spurious precision, but this paper shows there is huge uncertainty attached to these figures, primarily, but not exclusively, through their dependence on the future price of fossil fuels, which for gas is highly uncertain.

[5] See http://www.insidehousing.co.uk/price-of-carbon-soars-to-120-per-tonne-at-auction/6525902. article accessed 10.8.15

One of the most attractive ways to mitigate climate change damage is to stop subsidizing fossil fuels, part of which is the lack of a carbon price. The subsidy estimates prepared for the EC by Ecofys include a carbon cost of €50/tCO_{2e}in 2012. At this price, climate damage in the EU-28 in 2012 is estimated at €100 billion, double the other external costs (ignoring resource depletion costs, which are a pecuniary externality; Ecofys, 2014, fig 3.13). Ecofys recognizes that the carbon cost is highly uncertain and cites a range of studies, suggesting a range from €10-100/tCO_{2e}in 2012, although Ecofys itself considers a narrower range from €30-100/tCO_{2e}. If instead the break-even carbon cost is used, the range would if anything increase.

4 Short and long-run MACCs in the ESI

The marginal abatement cost curve, MACC, in the ESI can be computed in the short run from the options of fuel switching among the set of plant operating and in the long run assuming enough time to invest in technologies guided by the break-even carbon price. The amount of carbon saved for the specified level of electricity demand can then be computed as the difference between the emissions of the portfolio (or set of operating plant) at each carbon price and from that the MACC can be constructed, given assumptions about all costs including fuel costs, as in Cullen and Mansur (2014). They point to the sensitivity of the carbon price needed to stimulate a fuel switch between existing power stations in the US to the price of gas, noting that recent falls in the price of gas have reduced the required carbon price to achieve a reduction in ESI carbon emissions. Their approach is to econometrically estimate the emissions reduction from the US ESI of a fall in gas prices from $6 to $2, holding coal prices fixed, and map the resulting response curve into carbon prices.

Existing generation plant differs in variable costs (including start-up costs for plant that cycles, averaged over the period of up-time). Let v_{fi} be the variable O&M and start-up costs in £/MWh for plant type i (net of any ancillary payments), burning fuel subscript f (which in this example will be either coal or gas, subscripted c or g), f_i $(i = c, g)$ is the fuel cost in £/MWh$_{th}$, c is the carbon cost in £/tonne CO_2, H_{fi} is the heat rate of the generator, and γ_f (t CO_2/MWh$_{th}$) the carbon intensity of the fuel. The short-run marginal cost (SRMC) of plant i of fuel type f is

$$s_{fi} = v_{fi} + H_{fi}(f_i + \gamma_f c). \tag{4}$$

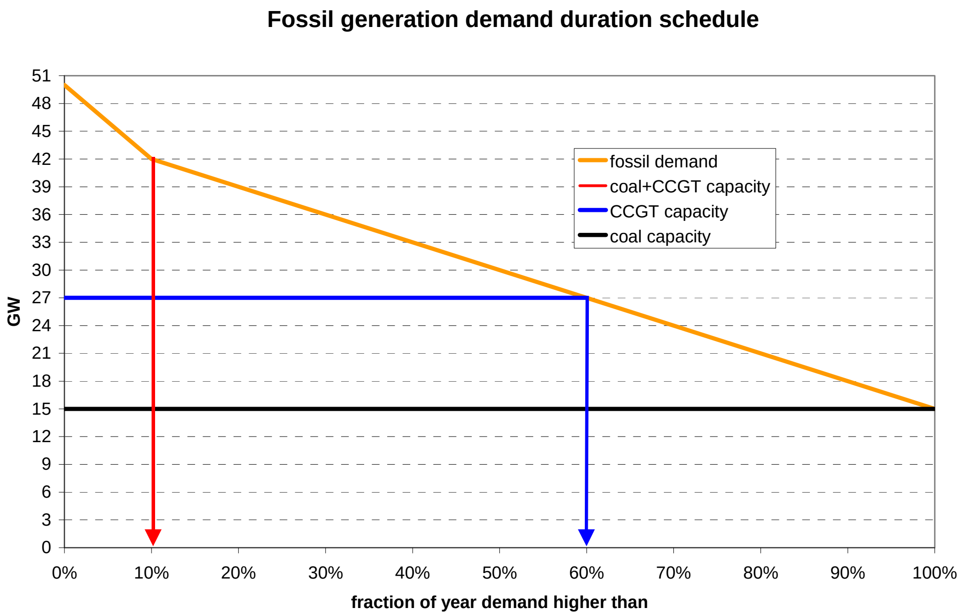

Figure 3: Illustrative fossil generation demand duration schedule, GB 2014

As noted above, the carbon intensity of gas is 0.19 tonnes CO_2/MWh_{th}, while the carbon intensity of coal is 0.341 tonnes CO_2/MWh_{th}. However, the efficiency of gas turbines is higher than typical coal plant, and as the relevant comparison is $\phi_{fi} \equiv \gamma_i/e_{fi}$, the effect is considerably larger. Thus for the more recent CCGTs, $e_g = 50\%$, so $H_g = 2$, and for sub-critical coal stations, $e_c = 38\%$, $H_g = 2.63$, $H_g\gamma_g = 0.38 = \phi_g$ tonnes CO_2/MWh_e (the carbon intensity of the electricity generated) while $H_c\gamma_c = 0.90 = \phi_c$ tonnes CO_2/MWh_e, more than twice as high. In addition to CCGTs, suppose that there is also peaking plant, taken as open-cycle gas turbines, OCGTs, with efficiency $e_p = 35\%$, $H_p = 2.86$, and $\phi_p = 0.54$ tonnes CO_2/MWh_e. Henceforth we indicate the plant type by these subscripts, c, g, and p.

Fig. 3 shows a linearized version of the adjusted load duration curve for fossil generation for Great Britain for 2014.[6] Ignoring ramping and other operational constraints, the cheapest plant will run first, and when demand exceeds its capacity, the next cheapest

[6]The raw data is given in http://www2.nationalgrid.com/UK/Industry-information/Electricity-transmission-operational-data/Data-Explorer/ and the Total Gross System Demand has been roughly adjusted for wind, PV and nuclear generation and linearised (although the difference from the non-linearised data is modest).

will run, and so on. The Appendix shows how to derive the short-run MACC given the various parameters and fuel costs.

4.1 Sensitivity of the short-run ESI MACC to fuel prices and efficiencies

To give a sense of the impact of fuel prices on the MACC consider the simple case in which there are two types of each coal and gas plant as shown in Table 4, and that the fuel prices have varied as over the past decade, also shown in Table 4. The variable costs v for these are similar and so will be ignored, further simplifying equation (7).

Table 4 Illustrative plants and fuel prices for GB

Plant	Capacity GW	e %	heat rate H	fuel price L	£/MWh$_{th}$ H
Large Coal	12	38%	2.63	£5	£10
Med Coal	3	35%	2.86	£5	£10
CCGT older	15	45%	2.22	£10	£20
CCGT newer	12	50%	2.0	£10	£20

Note: Individual capacities illustrative, total capacities representative of GB in 2014

Source: http://www2.nationalgrid.com/UK/Industry-information/Electricity-transmission-operational-data/Data-Explorer/

Fig. 4 shows the short-run MACCs for three combinations of fuel prices taken from Table 1 (at low gas prices and high coal prices gas runs baseload and so has already displaced coal).

The sequence of merit orders even for this simplified model is quite sensitive to the carbon price, and starts [LC,MC],NG,OG (meaning that LC runs before MC etc. with square brackets denoting baseload, after the square bracket mid-merit), then [LC,NG],NG,MC,OG, then [NG,LC], LC,MC,OG, then [NG,LC],LC,OG,MC, and finally [NG,OG],OG,LC, at which point all short-run decarbonization options have been exhausted.

4.2 Long-run MACC for electricity

Given enough time and consistency in carbon pricing, the long run allows zero carbon to displace a large fraction of fossil generation output (except for periods when peaking plant is required for system balancing and reserve plant for when intermittent generation

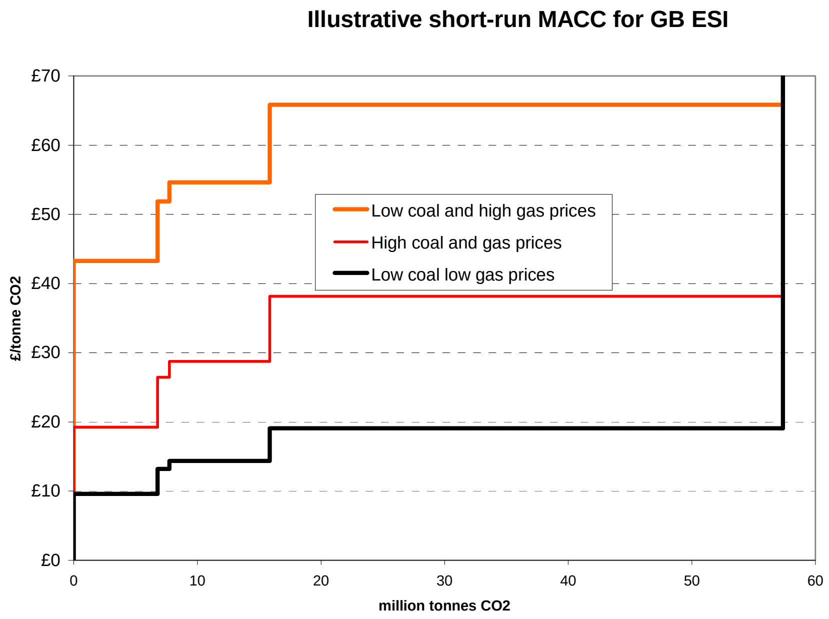

Figure 4: Illustrative short-run MACCs for GB, 2014 for various fuel prices

is inadequate to meet demand). The choice is now choosing how much zero-carbon plant to install and how much the fossil plant will operate, both of which will depend on the time horizon over which investments can be made. The only addition required to finding the break-even carbon price is to compute the amount of CO_2 abated as a result of these investments up to the chosen future date.

5 Designing suitable decarbonization policies

Although it is very attractive to work back and find a carbon price that supports mature renewable generation, this paper suggests that the resulting value for the required carbon price is highly sensitive to capital costs, the discount rate, and especially the price of fuel. These sensitivities decrease with increased zero-carbon penetration, but that is little comfort in the early investment stage. This creates a dilemma for policy design, as ideally the carbon price should be predictable to create credible investment decisions, and uniform across the economy(ies) at each date to deliver decarbonization at least cost. Certainly in the near term it seems unlikely that the consensus forecast of carbon prices will give the right signals for long-term highly durable investment decisions in the ESI. It also

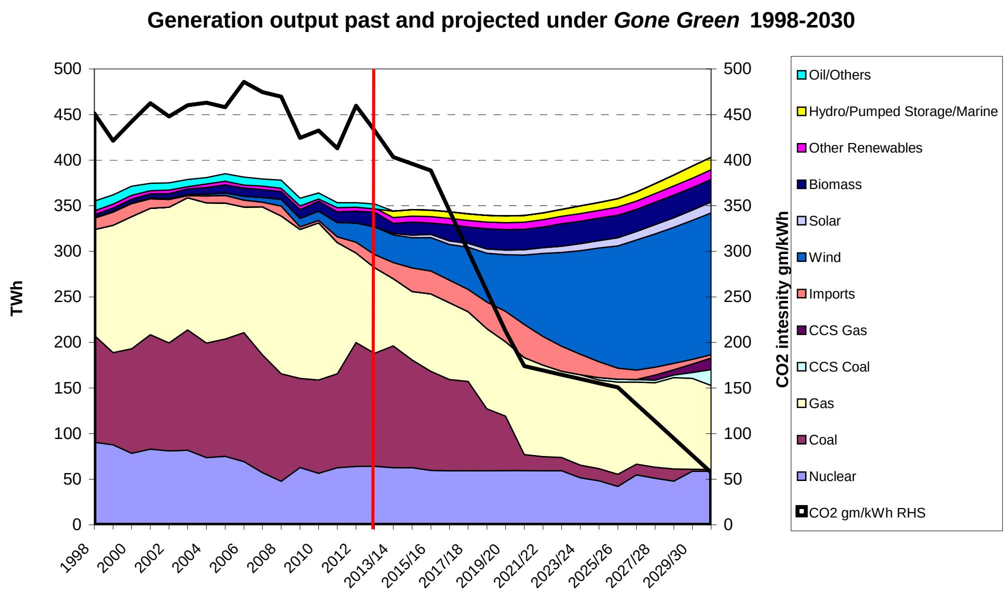

Figure 5: Sources: DECC Digest of UK Energy Statistics, National Grid (2015), DECC (2015a)

seems reasonable that, given the current consensus on the urgency of avoiding further carbon lock-in from such durable investment decisions, the objective is to decarbonize the ESI rapidly as the least worst regrets strategy. If that is accepted, then an immediate implication is that there should be no new unabated coal generation built. Indeed in 2016 the minister responsible in Britain announced that no coal generation would be allowed to operate after 2025, which will certainly ensure no new coal plant is built.

That leaves gas as the only acceptable fossil fuel for generation in the short and medium run. This is consistent with National Grid's (2015) *Gone Green* scenario (which, as its name suggests, is the most aggressive decarbonization scenario), shown in fig. 5. (Notice that the graph shows output, not capacity, which for gas may need to rise as its capacity factor falls.)

New investment will need to be that most suited to the evolving portfolio of low-carbon power stations. Storage hydro has the ideal combination of zero carbon and the ability to vary output across time in response to intermittent renewables but there is hardly any left unexploited in Europe. Most renewables except biomass (which has other sustainability problems) are intermittent and require demand *less* controllable supply to be able to accommodate large and rapid changes. That can be delivered through a combination of trading over wide areas, flexible generation, demand side response, and/or storage (ERP, 2015). All options require additional investment in the appropriate technologies and efficient price signals to make the investments profitable and their instantaneous operation efficient. The test of energy policies is whether they can deliver these objectives and decarbonization in a liberalized ESI.

5.1 Comparing policies

The range of policies for decarbonizing electricity include: (1) agreeing (usually internationally, as in the EU) a sequence of caps under a cap-and-trade system, (2) setting a carbon price (directly as a tax, or through a carbon price floor), (3) setting an emissions performance standard (EPS), and (4) providing long-term contracts. Designing and allocating such contracts opens up an additional and quite wide range of options. All four options (and several contractual variants) have been employed in the UK. Their respective merits should be judged against whether they are the least-cost solution to the market failures identified (biassed views on future carbon prices, missing risk and futures markets, learning spill-overs, etc.), whether they minimize distortions to efficient trade between technologies at home and internationally, whether they are perceived as credible by investors and thus reduce the cost of borrowing, whether or not they create political lock-in that reduces future flexibility, and what incentives they provide for desirable learning and innovation.

5.1.1 Agreeing caps for cap-and-trade

The fundamental objection to quotas discussed above remains, given that CO_2 is a highly persistent global stock pollutant. It is also politically the simplest instrument for putting a carbon price in place within a country and agreeing to coordinate between countries. The challenge is to transform it to deliver an adequate, credible and durable price, which requires modifying its form (e.g. through possibly soft collars). It is therefore tempting to leave the carbon price to the existing EU ETS and concentrate on its reform. Apart from the obvious objection that the current ETS price is too low and so fails to give suitable long-run investment signals, it faces additional problems. Until low-carbon generation dominates price determination, the electricity price will be set by fossil generation most of the time. That means fossil generation enjoys a natural hedge against fuel price uncertainty, and hence will appear lower risk and more attractive than equal expected value zero-carbon plant (Roques et al. 2008). Given the pressure to reform the ETS and raise the carbon price, the consequential risks facing coal-fired investment may be a sufficient deterrent (certainly in GB), and so it may provide a transition from largely coal-based ESIs to a fuel mix that has a large share of gas for some time while retaining some old coal to meet potential residual demand spikes in high net demand periods (winter in N Europe). In addition, a more aggressive low-carbon deployment strategy of the sort that makes sense in the ESI will lower the price of carbon facing the remaining sectors in the ESI, as the *Renewables Directive* demonstrated, and will not reduce the total emissions of CO_2 unless the cap is also reduced.

Clearly the current ETS does not give good signals on the kinds of investment needed for the future fuel mix (flexible generation, interconnectors, etc.). The spot price of carbon is also critical in determining whether existing coal or gas generation is favoured. Thus the capacity factor of coal plant in the island of Ireland has varied between below 40% and above 95% since Jan 2012 as the relative carbon-inclusive prices of coal and gas have varied.[7] Short-run efficiency between sectors and across trading partners needs a uniform but also adequate carbon price (and there is agreement that the EU ETS has failed to deliver an adequate price since 2008).

Raising the ETS price requires agreement to tighten the cap. The difficulty is that the national caps are valuable and agreeing to reduce them is perceived as harming domestic interests. If future allocations are uniformly scaled back, and if each Member State auctions off a sufficient fraction of its allocation, these states will receive much needed fiscal revenue which might form the motive for collective agreement, but evidence for success here is lacking.

5.1.2 Setting a carbon price

The carbon price could be the break-even price defined above and backed out of the abatement cost side, or the social cost of carbon (SCC) based on some view of future damages, as in the Stern Review (Stern, 2006). The break-even carbon price is too dependent on future forecasts to be credible by itself, while the SCC is quantitatively too ill-defined, as argued above. If one EU Member State (MS) sets a high Carbon Price Floor (CPF, as the UK considered) it will distort trade and be perceived as harming its competitiveness,

[7] *The Single Electricity Market Update (Q2 2015)* at http://www.allislandproject.org/en/homepage.aspx

while coordinating on a CPF may be even harder than coordinating on tighter caps (even if it has more attractive fiscal attractions), as MS's defend the right to set their own taxes more than almost any other policy.

5.1.3 Setting Emissions Performance Standards

The UK set an EPS for new power stations in the *Energy Act 2013* of 450gm/kWh averaged over 7,000 hours (3,150 tonnes CO_2 per MW capacity with some exemptions for part CCS plant). The intention is to make it uneconomic to build new unabated coal or oil-fired generation operating at base-load (which is the natural configuration for thermal plant) as such plant has roughly twice this emission factor. Existing coal plant could continue to operate a reduced number of hours per year to provide balancing services more cheaply than new peaking plant. Efficient new CCGT would qualify, as would less efficient peaking plant with an instantaneous emission factor above this level as it would only operate for less than 1,000 hours/yr. An EPS would thus allow gas to remain an attractive option but might discourage zero-carbon options for too long unless the EPS were progressively tightened. Announcing a future path of EPS that applied to all new investment (i.e., not grandfathering the EPS ruling at the date of investment) might encourage better adaptation to the future desired fuel mix, but might also have unintended consequences if it did not deliver sensible short (time-varying) and longer run prices. It would also be hard to make it credible to investors.

5.1.4 Long-term contracts

The final option is to provide long-term capacity contracts for zero-carbon plant, where the payment is conditional on availability (£ nominal/MW), as with the British fossil plant capacity auction (National Grid, 2014). Auctions work well given adequate competition but there are too few bidders for a new nuclear plant, for which an optimal procurement contract is more suited. The assured capacity payments would allow the capital cost to be financed cheaply from debt, while exposing generators to the correct short-run price signals for energy and balancing to determine B_i and θ_i. If necessary, the auction offers could be augmented by a suitable break-even carbon price, or eqivalently, the auctions would specify the volumes of zero-carbon and balancing capacity to procure. While this may be criticized as a move back to the Single Buyer model rejected by the EC energy directives, it retains competitive pressure (for the market), lowers the cost of finance by providing more predictable future revenue streams, and allows short-run dispatch to be market determined.

6 Conclusions

If ESI investment decisions are to be left to the market, then a number of market failures will need to be addressed. The most obvious is that CO_2 emissions should be properly priced to internalize that externality, but that is not the only externality, as RDD&D creates valuable public knowledge that is not reflected in the returns to developers. In addition to the difficulty of determining the right carbon price, the problem is amplified by a number of missing markets. ESI investments are highly durable and futures markets for more than a few years ahead are lacking. That might not matter if the policy environment were predictable, but that is far from the case. Perhaps more important, suitable risk markets are lacking. Fossil generators enjoy a natural hedge as they set the electricity price, and shift the volatility in fuel, carbon and electricity prices on to consumers and on to most zero-carbon generators, whose variable costs are close to zero. Consumers are further denied the option of insuring through future climate change mitigation options in existing markets.

Decarbonizing electricity is an attractive insurance policy against an increasingly likely high cost of future climate change damage (Arrow, 2007) but not one consumers can purchase, except via public policy. This is recognized both in international climate change negotiations and within the EU in the ETS. While cap-and-trade solutions are politically attractive as coordination mechanisms, they fail the test of resilience to shocks that underlies the literature on addressing persistent global stock externalities like GHGs. They need to be reformed to give credible, durable and adequate price signals. The social cost of carbon is highly uncertain, and as there is widespread agreement that the ESI should lead in decarbonizing, it appears operational and therefore attractive to set the carbon price at the break-even level at which zero-carbon options become commercially viable. Unfortunately, this break-even price is highly sensitive to fuel price and other uncertainties. If, for example, gas generation is to be outcompeted by wind, then a fall of \$10/MWh$_{th}$ (\$2.93/mmBTU) in the price of gas requires an increase of \$53/tonne CO_2 to restore parity.

Given the volatility in the forecast price of gas (and other risks), it would be difficult to set a carbon price now that would give credible signals over the life of new investment. Setting an EPS has the merits of ruling out some obviously unattractive choices like coal-fired generation, but is unlikely by itself to signal the kinds of investment needed for a low-carbon ESI with growing intermittent renewable power and (commercially) inflexible nuclear power. A carbon price floor is valuable in guiding short-run operating decisions (raising the cost of higher carbon plant and reducing its capacity factor), but long-term contracts have the advantage of addressing missing market problems (risk and futures markets) and can be designed to select enough zero-carbon capacity. Auctions offer the benefits of competitive pressure and some inducements to innovation, but the contract design (supplemented by other market and regulatory signals for e.g. balancing and transmission charging) needs to ensure efficient short-run operation, long-term locational guidance and adequate incentives for RDD&D. The design problem is to retain the benefits of competition in and for the market while balancing risk and incentives, as in the classic Principal-Agent problem, while allowing investors to express their diversity of views about the best route for decarbonization and properly rewarding learning spill-overs. Standard arguments suggest that it is preferable to separately identifying and providing any innovation support. That can also be subject to a competitive allocation. It might also be possible to allow less mature supported technologies to compete with mature technologies through a more complex package auction.

The extreme form of a risk-reducing contract would be a Single Buyer auctioning Power Purchase Agreements, typically 20-25 years, with an energy and capacity availability payment. The optimal energy payment is marginally above the short-run avoidable cost, and competition is for the capacity payment. This transfers all the risk to final consumers, minimizing risk costs, but at the expense of relying on the competence of an uncontestable single agent to make the right technology and innovation choices.

What this paper demonstrates is that climate mitigation strategies need to be tailored to each sector. In the critical power sector, policies need to address a whole set of missing markets in the face of the high level of uncertainty that make simple carbon pricing problematic, and in need of contractual support. The combination of an adequate carbon price to guide short-run operational decisions combined with long-run competitively allocated contracts and a better system of rewarding learning spill-overs is the implied package, and might serve to guide the development of the promised EU *Energy Union* (EC, 2015).

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7 Appendix Deriving the short-run MACC

Let G_{fi} be the (de-rated) capacity (in MW) of all plant of type f, i.[8] The load or demand duration curve is $D(h)$, which is demand in the h^{th} highest demand hour, and $0 \leq h \leq Y$ (the number of hours in the year). Suppose that at a zero carbon price (and suitable coal and gas prices) coal is the cheapest plant, i.e. that the SRMCs are

$$s_c = v_c + H_c f_c < s_g = v_g + H_g f_g < s_p = v_p + H_{pf_p}. \tag{5}$$

Coal will run as base-load, and its running hours ($=B_c Y$) will be determined by $h_c = \arg\max D(h) \leq G_c$. Total generation from coal will be

$$y_c = h_c G_c + \int_{h_c}^{Y} D(h) dh.$$

Total emissions will be $E_c = \phi_c y_c$. Similarly, output from CCGTs will be defined by $h_g = \arg\max D(h) \leq G_c + G_g$, and generation and emissions will be

$$y_g = h_g G_g + \int_{h_g}^{h_c} D(h) dh, \quad E_g = \phi_g y_g.$$

Finally, peaking output will run the remaining h_g hours with generation and emissions

$$y_p = \int_{0}^{h_g} D(h) dh, \quad E_p = \phi_p y_p.$$

Peaking plant is assumed not to be displaced as the carbon price rises as it provides ancillary services (mainly flexibility, low start-up costs and high ramp rates) and so will be held constant in what follows.

As the carbon price increases, so the SRMC of coal generation rises faster than CCGT, and at some price c_g plants with the two fuels will be equally costly. This will occur at

$$s_c = v_c + H_c(f_c + \gamma_c c_g) = s_g = v_g + H_g(f_g + \gamma_g c_g), \tag{6}$$

$$c_g = \frac{v_g - v_c + H_g f_g - H_c f_c}{\gamma_c H_c - \gamma_g H_g}. \tag{7}$$

Above that carbon price in this stark model, CCGT will displace all coal for baseload and coal will become mid-merit (together with the remaining CCGTs), so now $h_g^* =$

[8] The de-rated capacity is the average amount of capacity available, allowing for forced and planned outages.

$\arg\max D(h) \leq G_g$ and $h_c^* = \arg\max D(h) \leq G_c + G_g$, the previous value of h_g. The new values for outputs and emissions will be

$$\begin{aligned} y_g^* &= h_g^* G_g + \int_{h_g}^{Y} D(h)dh, \quad E_g^* = \phi_g y_g^*, \\ y_c^* &= h_c^* G_c + \int_{h_c}^{h_g} D(h)dh, \quad E_c^* = \phi_c y_c^*. \end{aligned}$$

The MACC will now have the cost of decarbonization at c_g and the volume of emissions abated at $\Delta E = \phi_c(y_c^* - y_c) + \phi_g(y_g^* - y_g)$. The sensitivity of the carbon price to the fuel price can be readily deduced by differentiating (7):

$$\frac{\partial c_g}{\partial f_g} = \frac{H_g}{\gamma_c H_c - \gamma_g H_g}, \quad \frac{\partial c_g}{\partial f_c} = \frac{-H_c}{\gamma_c H_c - \gamma_g H_g}.$$

With the heat rates and emissions coefficients above, $\partial c_g/\partial f_g = 3.9$, and $\partial c_g/\partial f_g = -5.1$. The are large multiples given that one-year ahead gas forecast prices vary from £16-£28/MWh$_{th}$ and coal prices from £7-10/MWh$_{th}$ (DECC, 2014b). Thus holding coal prices constant and varying the gas price over this range, the cost of abating 68 kt CO_2 could vary by $3.9 \times £12 = £46$/tonne, while a rise in coal prices of £3/MWh$_{th}$ (holding gas prices constant) could lower the abatement cost by $5.1 \times £3 = £15$/tonne, given the plant assumptions behind fig. 2.

In practice there will be a range of coal and CCGT plant of varying efficiencies. The MACC can be more finely graduated by considering variations in heat rates for different models of coal and CCGT plant. The least efficient coal plant will have heat rate $H_{nc} > H_{ic}$, $i = 1, ...n - 1$. The most efficient CCGT will have heat rate $H_{1g} < H_{ig}$, $i = 2, ...m$, (assuming for simplicity that the variable costs are the same within each fuel type, but this assumption can be readily relaxed). Equation (7) gives the carbon price at which the most efficient CCGT displaces the least efficient coal plant, with suitable subscripts on the heat rates. Subsequent steps have the least efficient gas displacing more efficient coal, until all coal is displaced for baseload running and coal moves to mid-merit.