Response to DTI's *Energy Review*

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1. Introduction

An Energy Policy is, ideally, a coherent set of interventions in the economy directed to achieving specified objectives that it is thought cannot be achieved by unaided market forces, either because of market failures, or because the objectives of the policy maker diverge from those of the market participants. These interventions can take the form of taxes and subsidies designed to influence market decisions, and standards, requirements or prohibitions, again designed to achieve certain objectives. Even in the period that the UK argued for a *laissez faire* approach to energy markets (leaving them to standard competition policy), the Government still intervened extensively with various energy taxes. Moreover, any coherent energy policy must contain a coherent approach to energy taxation, and it is hard to discern such in current practice. ***An important task of the Energy Review should be to consider whether current energy taxes are fit for purpose, and if not, in what direction they should be changed***, recognising the political reality that tax reforms can be difficult, and may require an evolutionary approach (of the kind exemplified by the fuel tax escalator that over time dramatically changed the UK's transport fuel tax rate from one of the lowest in Europe to the highest).

The evidence that energy taxation may lack coherence is that there is a wide divergence in excise taxes across fuels within the UK and also on the same fuel across different EU countries. Figure 1 shows the variation in oil excise taxation across various OECD countries in the tax per tonne oil equivalent (TOE) in 2002. The UK had the highest tax on oil in Europe, more than 50% above the EU average tax of 306 €/TOE. To put the level of taxes into perspective, oil product prices in 2002 (spot Amsterdam) averaged about 200 €/TOE (190 $/TOE), although since then oil prices have more than doubled. Figure 1 also shows the oil tax revenue as a share of GDP (reading on the right hand y-axis), where the UK value is over 2% compared to the EU-15 average of 1.8%, and on the same axis, the road fuel tax revenue as a share of GDP, where again the UK stands out as a high tax economy.

In most countries oil taxation is overwhelmingly concentrated on road fuels (petrol and diesel). Energy taxes are indirect taxes, and account for about one-fifth of indirect tax

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[*] Research Director, Electricity Policy Research Group, an ESRC-supported research group funded under the *Towards a Sustainable Energy Economy* initiative. This response draws on work of the group, particularly Michael Pollitt and Tooraj Jamasb (who have studied the collapse of UK R&D), Karsten Neuhoff (for his expertise on carbon allocation and renewables support mechanisms), Fabien Roques and Bill Nuttall (for their expertise on eral options and Nuclear power), David Reiner (drawing on his knowledge of carbon capture and storage), Liz Hooper, and associates Chris Hope (for his work on the social cost of carbon), and Roger Kemp (for his expertise on safety issues). The reportt does not necessarily reflect the views of all its members, nor those of the ESRC. Details of the EPRG and reports cited in this submission are available at http://www.electricitypolicy.org.uk/.

revenue in the EU-15. As such, energy taxes are fiscally important, and although they may appear modest compared to other major taxes, such as income taxes, energy tax *rates* can be extremely high – the average EU-15 oil tax *rate* in figure 1 in 2002 was 180% of the pre-tax (c.i.f.) price, although as the price of oil fluctuates more than excise taxes, the rate varies (and was thus substantially lower in 2005). Newbery (2005a) considers to what extent these oil taxes can be considered as optimal import tariffs on oil (at the EU level) and finds a plausible range of between €30 and €120/TOE (to which must be added other reasons for taxation, discussed below).

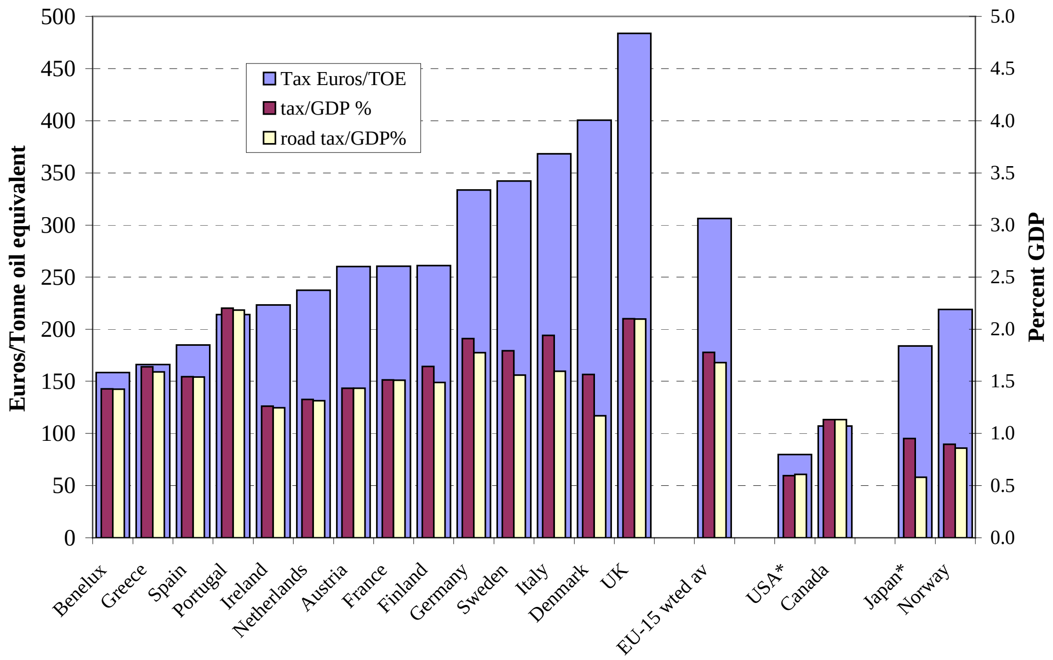

Figure 1 Taxes on oil and oil products, 2002

Notes: * 2001 data. Exclusive of VAT [1]

Sources: EU countries: EC (2003); others: OECD (2003a); oil from OECD (2003b)

The most obvious location of inefficient taxation lies in the treatment of domestic fuels, where figure 2 shows the varied treatment of taxes across fuels within countries and between EU countries. Before the European Emissions Trading System (ETS) was introduced, the UK subsidised domestic gas and electricity consumption (by affording them a lower than standard rate of VAT) while heavily taxing heating oil (although this was justified in preventing diversion of kerosene into diesel for transport use). The ETS started in 2005 and has increased the cost of wholesale electricity, as the generating stations that set the

[1] The data for EU countries are comparable, but data for the four countries at the right come from a different source, which for EU countries seems to understate tax revenue on oil as a base (perhaps because revenue is allocated to the base, such as sulphur or carbon, and not then aggregated up to the carrier fuel). Conversion factors for products taken from BP (2004) and IEA (2004).

price of electricity (overwhelmingly fossil-fired) face the opportunity cost of the CO_2 they release. The market for EU Emission Allowances (EUAs) has been volatile, as appendix figure A1 shows. Moreover, the price of EUAs can be expected to feed through to the wholesale price of electricity in a competitive market, and the evidence in Appendix 1 supports this. Gas sold to domestic customers, in contrast, does not have to account for the CO_2 released when burned and to that extent a further tax distortion is introduced into domestic fuel use.

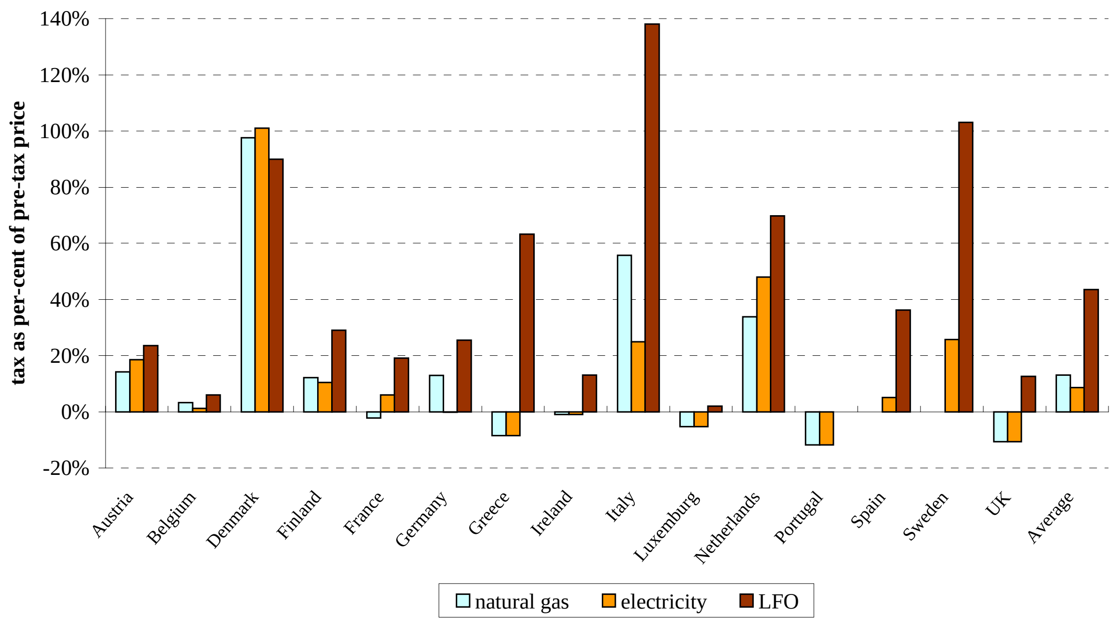

Figure 2 Effective tax rates on EU domestic fuels, 2002, net of standard VAT (IEA 2004)

2. Principles for energy market intervention

A key objective of the Energy White Paper was "To promote competitive markets in the UK and beyond, helping to raise the rate of sustainable economic growth and to improve our productivity." Energy policy should therefore be market friendly, and should be largely confined to addressing market failures that are sufficiently serious to require action (and that action might be to ensure that the market works better). The main market failures involve climate change and pollution, RD&D, security of supply, and informational asymmetries.

2.1 *Climate change and greenhouse gas externalities*

As greenhouse gases (GHG) are a pure public bad, unless properly priced or restrained they will be released in excessive amounts. The ETS is an EU-wide attempt to internalise these costs, and is best seen as playing a leading part in the Kyoto process (which is at present inadequate to the task of properly responding to the threats of climate change). Policy towards harmful emissions can either take the form of setting emission limits at each date (the "quantity" approach) or by setting a charge for releasing emissions (the "tax" approach). The quantity approach allocates EUAs to European countries who then allocate the allowances to companies on the basis of baseline emissions. The appropriate charge for releasing GHG is the social cost of carbon,[2] which measures the present value of the future cost of releasing another tonne of carbon today. There are good arguments for claiming that the social cost of carbon is insensitive to the exact evolution of GHGs, and will only increase at about 2% per year in real terms (Hope, 2005). Weitzman (1974) started a lengthy debate about the relative merits of "quantities vs. taxes", and the consensus on GHGs is that setting a charge or tax on carbon is theoretically superior to fixing an emission target.

The main reason for preferring a stable price for carbon over time, rather than fixing the quantity at each date and allowing trading to determine a possibly volatile price, is that GHG are long-lived, so that there is little difference in the cost of releasing a tonne of carbon now or in the (reasonable) future. There are additional reasons, discussed further below, of which two are immediately relevant to UK and EU energy policy. The first is that stable carbon prices reduce investment risks in low-carbon technologies. The second is that fixing the price rather than the quantity of EUAs reduces the market power of gas producers and suppliers, as explained in Appendix 1.

The ETS and the Kyoto Protocol, are, like almost all other cap-and-trade systems for addressing environmental pollution, quantity based, for the sound reason that it is easier to determine an initial allocation of permits between countries and companies than it is to devolve tax-raising powers to an international body. If stabilising the carbon price is desirable, then several mechanisms are available. The simplest is to allow banking and borrowing, so that EUAs can be intertemporally traded and their price in different years will be arbitraged. This already happens for the first period up to the end of 2007. Figure A1 shows that the price of EUAs for use in 2006 closely track those for use in 2007. The main problem facing the ETS is that trading for the next phase depends on allocations that are not yet agreed, while the post 2012 period depends on a new Kyoto settlement.[3] A more ambitious approach would be to set up an International Bank for Emissions Trading (IBET). This would be granted to right to issue Emission Allowances (EAs), in addition to those allocated under any Treaty (such as the ETS or Kyoto). The IBET would act like a central bank in its role of maintaining a currency peg, buying outstanding EAs when their price was in danger of falling below the lower limit and selling (issuing) EAs when their price rose above the upper limit.

The UK intends to play a major role in international climate change negotiations, and therefore needs clear principles of engagement with that debate. There is considerable disagreement about desirable reductions in emissions relative to Business as Usual, but there may be greater agreement about the social cost of carbon, particularly as it appears relatively insensitive to the exact evolution of GHG emissions. There is a good case for determining emissions by adjusting (regional) permit allocations to maintain a moderately stable price of carbon. As new information about the social cost of carbon arrives, the price (or price path)

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[2] It is convenient to choose carbon equivalent as the unit of measurement (carbon for short), recognising that a tonne of each GHG has a different number of tonnes carbon equivalent (tC), and that EUAs are priced per tonne of CO_2, where 1 tC = 3.67 t CO_2. To find the equivalent price of carbon multiply the price of CO_2 by 3.67.

[3] The way in which future allocations are made can create considerable distortions that are discussed in more detail in Appendix 3.

can be adjusted and allocations also adjusted to maintain the price (possibly with some fraction allocated to the IBET, whose profits could be used to finance clean development in developing countries).

One of the implications of thinking about a carbon price rather than a carbon allocation (or reduction target) is that it clarifies the importance of international negotiations, as follows. If the UK were the sole country taking steps to mitigate climate change, and if the UK were selfishly concerned only with the impact of climate change on UK citizens, then the social cost of carbon (SCC) for the UK alone would be roughly proportional to UK's share of world GDP, which is about 5% (at market exchange rates in 2005).[4] To put that into perspective, taking DEFRA's central estimate for the social cost of carbon (SCC) of £35/tC (see Appendix 1), the UK's SCC would be £1.75/tC or 47p/tonne CO_2, or less than 3% of the current EUA price. Of course, if we attached some weight to the impact of climate change on other countries, then the weight would be higher, and the relevant question would be the proper allocation of (opportunity) costs to the UK in aiding the rest of the world through reductions in our CO_2 emissions or by various forms of aid.

If, as at present, we have agreed a joint policy with the rest of the EU, but with no-one else, and if the EU were acting solely in its own interest, then each EU member state might weight the global SCC by the EU's share of global GDP of 30% (which, on the calculation above, would be about 15% of the current EUA price). If we believe that our (the UK and/or the EU) presence is critical to sustaining the Kyoto process, then we might count the entire Annex 1 country share (58% at purchasing power parity).[5] If we attach some weight to the rest of the world's welfare even though they are not required to take preventive measures then the weight would be higher still. ***Deciding the weight to attach to the social cost of carbon should be a central element in UK climate change policy, as should pressing for wider international burden sharing agreements for mitigating climate change.***

A further implication is that there is little point in exceeding internationally agreed targets unless to do so increases the extent of compliance by the rest of the world (or we wish to do so out of good will to the rest of the world). Similarly, there would be little point in subsidising carbon reductions beyond the price implied by trading allowances within the relevant trading area (the EU for ETS), except as a mechanism for subsidising RD&D, which is discussed below. One of the issues that will need to be addressed is that the ETS only covers one of the GHGs, CO_2, and only some of the sectors. Nevertheless, we are also subject to the Kyoto Protocol, which applies to all sectors and gases, and ***the Government should***

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[4] This is only approximate, as the damage of climate change is only roughly proportional to GDP, and may be unequally distributed across the globe, with possibly the larger share occurring in the tropics. There is also the vexed issue of the social weights to attach to damage at different times, in different states of the world and for different countries. The utility loss of damage in future states where GDP is lower (because of the climate change) may be higher than if GDP is higher (because of faster growth or more effective mitigation and adaptation).

[5] The developed countries share of global GDP is lower at purchasing power parity (PPP) than market exchange rates, but this might reflect the likelihood that the damage of climate change is more correlated with PPP income (both as a measure of well-being and because developed countries can probably adapt better than developing countries.

press for the ETS to be similarly extended to cover all GHGs and sectors. Otherwise, the price of GHGs for sectors not covered by the ETS might be set initially at the EUA price (for carbon equivalent, or best estimate), and other taxes on energy adjusted appropriately to meet the Kyoto targets. If we can persuade the EU (or a wider group of nations) to extend coverage then this problem will disappear.

Note that policy towards climate change adaptation (i.e. taking steps to reduce the consequences to the UK of future climate change) is far more straightforward, as it only requires a prediction of the likely consequences of climate change and a simple social cost-benefit analysis of actions to reduce the costs of these changes. As many actions are public goods (flood protection, restrictions on where housing can be built, etc), the Government will still need to be actively involved, but does not need co-operation with the rest of the world.

If we consider the case of road fuel excises, a logical approach to integrating climate change policy with other objectives might be to start from the optimal oil import tax (provided we are confident that the EU will effectively support this by agreeing minimum excises on oil products at defensible levels), add the carbon price and (very modest) taxes for other non-GHG emissions such as particulates, for noise and water pollution, and finally add the road user cost (maintenance expenditures, non-internalised accident costs, and interest on the capital value as set out in Newbery, 1998, 2005a, b). These road user costs are effectively a charge for using the road network (just as electricity users have to pay a charge for the national grid and regional distribution networks, and gas users for the pipeline system). Newbery (2005b) estimates the total pre-road user charge petrol tax (covering all emissions and tariffs) as € 162/'000 litres, and including road user charges the justified total petrol fuel tax would be € 562/'000 litres or about 40p/litre for the excise tax. For diesel the non-road charge element would be €232/'000 litres, giving a total road diesel excise of € 732/'000 litres (or 50p/litre), although in both cases some fraction could be recovered from annual license fees. At these (high) estimates of appropriate tax levels the UK would still be overtaxing both road fuels.

2.2 *RD&D support*

Research and Development (R&D) is a public good unless patent protection is adequate to ensure adequate expenditure. The same is true to a more limited extent for Research, Development and Deployment (RD&D), if there are significant learning or demonstration effects from deployment. The evidence in figure 3 is that UK Government energy R&D has collapsed since the energy industries were liberalised, as argued was predictable by Jamasb and Pollitt, (2005). It seems that the Government hoped that energy R&D would be undertaken by the private sector after privatising all the energy industries, but this was never realistic given that R&D is a public good, and hence likely to be under-supplied by a competitive market. When energy R&D was undertaken by nationalised industries and specialised agencies such public good aspects could be recognised (which is not to say that the R&D was necessarily cost-effective), but once only private returns are relevant this support disappears. Of course, that is true for all R&D to the extent that it cannot be protected and commercialised, and is a general reason for public support, but clearly the Government has in the past taken particular responsibility for supporting energy R&D as part of wider energy policy, and that role needs to be reinstated.

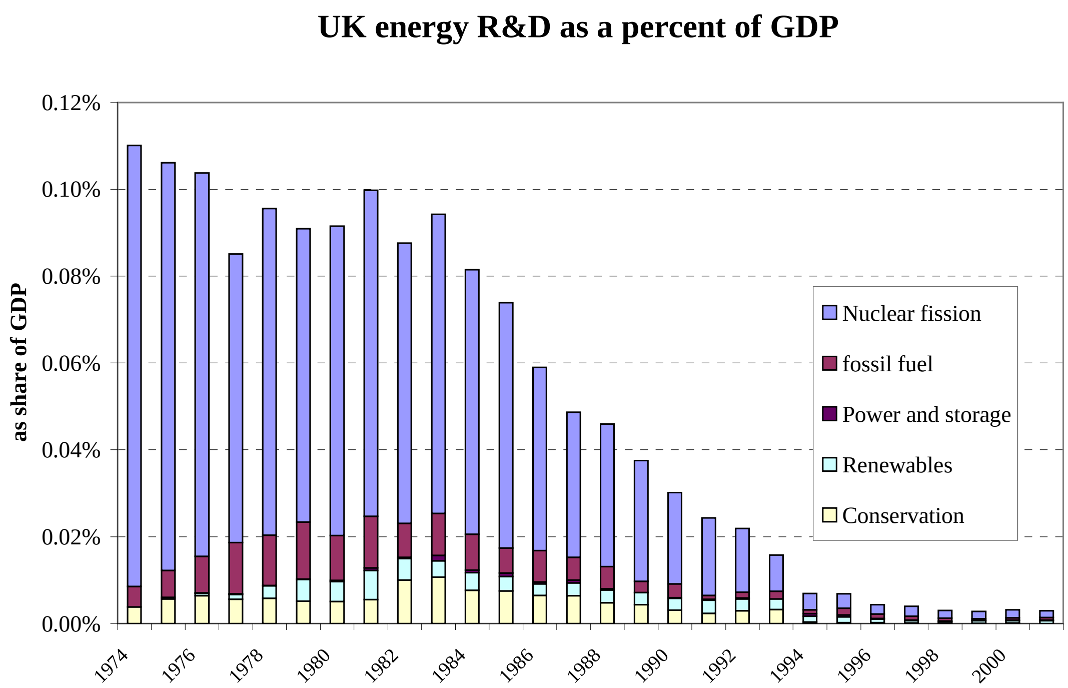

Figure 3 The collapse of UK Government energy R&D expenditure

Energy R&D has, however, an additional claim for public support, as R&D in low-carbon (low-C) technologies has the potential to make them attractive to a large market that may not otherwise adequately internalise the GHG externality, so there is an additional benefit over and above the normal commercial returns to successful innovation. Support for low-C technologies can be justified to the extent that it has a reasonable chance of wider scale adoption that leads to GHG mitigation whose extra value (measured by the social cost of carbon) justifies the initial extra costs.

This is where the DTI should take an economic approach to mechanisms for supporting low-carbon RD&D. The most compelling case is where a large number of countries agree to collectively support RD&D in low-C technologies. The benefits will accrue first to the collective (assuming they have also signed up to reducing emissions and wish to do so at least cost), and second to the rest of the world *provided* the new technologies are commercially attractive to them. The distinction is that the EU (for example) is already internalising the cost of carbon, so that low-C technologies are more likely to be commercially attractive inside the EU than in other countries that are not as fully pricing carbon.

One appealing joint mechanism might be an agreement to levy an R&D tax on electricity to fund R&D, just as the US Electric Power Research Institute (EPRI) had a 1% turnover charge on electricity to fund electricity R&D. Ofgem is already moving in a sensible direction on the encouragement of R&D funding in a deregulated environment. In 2004 it introduced the Innovation Funding Incentive (IFI) for electricity distribution network operators (DNOs) (Ofgem, 2004). DNOs are allowed to spend up to 0.5% of revenue on eligible IFI projects. They can then recover up to 90% of R&D expenditures initially (falling to 70% by 2010) in additional charges to customers. IFI projects can focus on any aspect of DNO system asset management and are aimed at technical developments that deliver value to customers. Such a model could be extended more widely, provided it was additional to the current (low) levels of UK Government R&D support.

If our RD&D support is not in response to a collective agreement or does not increase the chance of such an agreement (explicit or tacit, in that the other countries may be shamed into additional action, as in the case of some states in the US), then the benefits accruing to the UK will be considerably diminished, unless we make a break-through that makes a new technology competitive and demanded by a large market. In the latter case there is no obvious difference in support for low-C technologies and any other potentially exportable profitable technology, and so no extra case for additional support.

To be more specific, the costs of support are reasonably simple to estimate (given some projected rate of research and/or deployment), but the benefits will fall into one or more of four categories:

(i) direct future cost savings measured by the value of carbon saved within the UK, valued at the ETS price (or, if the ETS collapses, the relevant and rather low *UK* social cost of carbon, UKSCC);

(ii) future cost savings for the relevant group of countries (e.g. the EU under the ETS, or Annex 1 countries), measured by the relevant area-wide social cost of carbon, to the extent that the expenditure is to discharge an obligation arising from a treaty agreement of burden sharing of low-C RD&D. For example, if all EU countries sign up to meet a renewables obligation of x% of electricity generation or y MWh, then the UK can support such deployment with least-cost subsidies (discussed further below);

(iii) future UK profits from commercialising the low-C technology successfully, where again an economic approach is needed to justify any additional public support, given that this is potentially a commercial reward and should therefore be a commercial decision, and

(iv) to the extent that there is a significant impact on the demand for low-C generation, there may be an impact on the global price of fossil fuels. Oil is hardly used in generation, so the main impact here would be on the price of gas, and would only work if so long as gas and oil prices remain linked. This benefit is akin to the optimal tariff argument for taxes on oil (and similarly gas from outside the EU). As Appendix 1 points out, the current design of the ETS actually works in the opposite direction, tending to increase the price of gas and the market power of gas suppliers.

Decentralising the cost of this activity (burden-sharing across the EU and hopefully more widely) is in the UK’s interest, given her small share in the collective benefit of mitigating climate change acting in isolation. ***Devising suitable instruments for burden sharing which encourage the most cost-effective research is a challenging and important task for EU energy policy on which we would hope the UK would take a lead.***

2.3 *Security of supply and market power*

Recent surges in gas prices, the failure of the Rough gas storage facility, and allegations of market manipulation in the use of the gas interconnector, combined with a more rapid than expected decline in indigenous gas production and a rapid increase in forecast gas imports, have all highlighted the risks to security of gas supply. Not surprisingly, the Energy White Paper listed as a key objective "To maintain the reliability of energy supplies" and the Energy Review notes that

- "Progress in introducing truly open energy markets in the EU has been slow over the last three years;
- There has been a general heightening of sensitivity around global energy issues, affecting perceptions of the security of supply from major exporter countries and contributing to higher price volatility."

As energy policy is directed to correcting energy market failures, one must ask what market failures justify any additional intervention to obtain (additional) security of supply. The normal argument in a well-functioning market is that price rises signal scarcity, and cause consumers to hedge risks through contracts, build storage and provide the necessary reserve capacity and/or dual-fuel capabilities to deal with cases of excess demand, plant failure, or supply disruptions. If the government mandates additional storage, spare capacity, or fuel diversity, then the market will find these activities less profitable, and will respond by reducing their own supply of these facilities, in the limit replacing public actions one-for-one until there is no private supply. Thus if storage is mandated because considered insufficient, then the expected returns to private storage will fall below the market level and no extra commercial storage will be built (all storage will be deemed that needed to meet the mandate, which by hypothesis is above the equilibrium amount).

Current shortages were not anticipated by the market, for if they were then it would have been profitable to secure contracted supplies, possibly to have built more storage, or to have advanced the date of commissioning new LNG terminals. It is not clear that any public body such as DTI could have made better forecasts. Setting up the Joint Energy Security Of Supply Working Group was a useful step in collecting and disseminating information, although it is somewhat surprising that the last report is dated November 2004.

The UK has wisely refrained from imposing price caps on wholesale gas and electricity markets (at least, in the absence of evidence of market abuse – there was a price cap on electricity for that reason from 1994-6). If market prices can rise to signal scarcity, then in theory the market should signal efficient responses to those price rises and anticipated scarcity. The main potential market failure is market power, which may be a problem in supplying gas through the interconnector (if Continental and/or external suppliers restrict supply to increase UK sales prices). This should be addressed in the first instance through a complaint to the Commission (and that has been the route adopted). If it proves hard to remedy Continental energy market imperfections, the main worry is that market prices become harder to predict as they may be less determined by fundamentals and more by short-run inelasticities that allow oligopolistic mark-ups above competitive levels. The standard remedy is for increased contract coverage, and one then asks whether there is a bias to under-contract.

Here the main risk is that UK suppliers may find it cheaper to (occasionally) declare bankruptcy rather than buy expensive gas or electricity to meet contracts to deliver. That is best addressed by normal financial regulation for poorly-informed counterparties (domestic customers in particular), and less onerous regulation for well-informed customers, who can judge the counter-party risk themselves. While it may be socially desirable to increase contract cover above the level that seems commercially desirable (because of the public good of reducing market power), it is not clear whether there is any simple method of achieving this that would not be costly and intrusive. In futures markets liquidity is increased and transaction costs reduced, encouraging contracting, by standardising contracts and publishing contract coverage and open interest. ***Ofgem should clearly monitor market liquidity and transparency and endeavour to increase both.***

If expectations of Gazprom's reliability have deteriorated, does that warrant intervention? Again, contract cover is a partial solution, provided it can be enforced (and force majeure may render the contracts void). One question is whether the macro-economic effects of energy supply disruption may lead to systematic market failure (and a case for intervening to reduce supply vulnerability). Here the contrast between gas and oil is important. An oil embargo can be partially mitigated by switching suppliers and drawing down stocks widely distributed across the globe. If Gazprom (or a transit country) disrupts supplies, it may be very difficult for the UK to switch to alternative sources, as we are reliant on the interconnector for pipeline gas, and spot LNG markets are thin, relative to the volume of gas pipeline imports from Russia.

The external (or macro-economic) costs of gas disruption (i.e. those not reflected in prices that guide storage and contract decisions) are therefore likely to be higher than with oil. The IEA decided to require 90 days oil storage to deal with oil disruptions, and on that basis the UK might argue for a considerable increase in gas storage. The problem, noted above, is that increased mandated storage will destroy the commercial market for storage, unless it is held off the market except for well-defined conditions (like the US Strategic Petroleum Reserve).

Market power distortions *may* be a problem for the gas market if the price is linked to the price of oil and hence lacks the seasonality that gives the correct signals for storage investment, but this can be exaggerated. If much gas is bought on long-term contract (typically the case for inflexible supplies from LNG, offshore gas-fields, long-distance pipeline, where using the full capacity of the facility may not match varying seasonal demands), then it is likely to have a capacity and volume element (perhaps concealed as a take-or-pay contract). A well-functioning spot market will then deliver highly seasonal prices where storage capacity is (at the margin) expensive and scarce. This seems to have been illustrated recently in Britain during November 2005, when the spot price differences across the inter-connector should have signalled full capacity utilisation, but the inter-connector was only 60% full. In effect, the Continental spot market was illiquid and the prices quoted were not true scarcity prices (or there was abuse of market power, or both). Certainly UK NBP prices signalled scarcity prices that would encourage domestic storage investment.

2.4 *Diversity of supply*

Britain is on current projections increasingly dependent on gas and hence its diversity of fuel supply is projected to decrease quite sharply over the next decade. Does this justify interventions to reduce imported gas dependence?

Renewables policy aims to increase the share of electricity generated by renewable sources and to that extent will increase diversity above the level chosen by the unaided market. The ETS has a mixed effect, as it makes low-C generation (like nuclear power) more competitive (potentially reducing gas imports) but makes coal more costly, encouraging gas-fired generation, which increases gas dependency (although high gas prices ought to reduce this effect). With peak and mid-merit electricity prices increasingly set by gas (and carbon) prices, electricity consumers become more exposed to gas price risks, which recent events suggest can be significant. If Britain has market power in the import gas market then, as with oil taxation, there may be a case for an optimal gas import tariff to reflect that market power, and this might take the form of required storage of so many days import capacity paid for by importers, to reflect a possible under-supply of storage, as noted above.

The lack of a long-term contract for (or option on the price of) carbon, which could be an important aspect of long-term contracts for low-C generation, may be a cause for concern and a possible market failure. In Finland, a new nuclear power station is being financed by long-term contracts with large industrial consumers (in the paper and pulp industries that have high energy demands and long time horizons), partly as a hedge against future high carbon prices, but the prospect for similar long-term contracts in the UK is less evident. Nuclear power could offer long-term supplies at prices indexed to the RPI (particularly if, as would seem logical, it could issue indexed long-term debt to finance part of the construction costs), and electricity supply companies, many of whom are short in the wholesale market with larger retail sales than generation, may find such contracts attractive. The need for such carbon contracts is considered further in Appendix 2.

2.5 *Other information asymmetries and barriers to using low-carbon technologies*

There may be a case for intervening to correct systematic biases in decision-making where there is a systematic under-response compared to efficient decisions that should be taken if well-informed and rational agents were confronted with the right prices (including the prices for energy and emissions). The classic example is energy conservation or energy efficiency, where consumers may not be able to make informed life-cycle decisions, where labelling is important but may not be adequate, and where standards may have an important role (e.g. in appliances, for standby power consumption, and in buildings).

Smart metering has now become cheap (mainly as a result of ENEL installing some 30 million in Italy) and its deployment would assist the deployment of distributed generation. Ofgem could help by ensuring that subsidies available for e.g. micro-generation or solar PV are automatically paid when suppliers install such facilities (apparently this is not the case).

3 Other distortions than need addressing

The current system of allocating allowances (EUAs) to power stations was agreed during negotiations over the design of the ETS, and has the effect of making large income transfers from consumers to generating companies, which are a pure addition to the profits of those companies as the carbon price is passed straight through in higher electricity prices. This has already attracted considerable consumer objections and was a major factor calling for the EC investigation into high energy prices last year. It would be desirable for both fiscal reasons and to retain consumer support if these windfall (i.e. not compensatory) transfers were phased out as soon as possible, and that the distorting effects of most proposed future allocations were minimised, as explained in more detail in Appendix 3.

Answers to questions posed by DTI

Q.1. What more could the government do on the demand or supply side for energy to ensure that the UK's long-term goal of reducing carbon emissions is met?

On the supply side, there are two major obstacles to investments in electricity generation that would lower carbon emissions: economics and uncertainty. Most low-C technologies are capital-intensive but have low (or virtually zero) running costs. Their economics depend critically on the capital cost per kW, their availability, and the value of the electricity they sell. The value of electricity depends in term on the cost of generation of the price setting plant, which in Britain is increasingly gas-fired, and the carbon cost. Future carbon prices (and even the commitment to the ETS or its successor) are uncertain, and this chills investments whose viability depends on an adequately certain level of future carbon price. ***Creating a suitable instrument to reduce this risk is therefore a key task facing the Government*** (and the EU). Possible approaches are discussed in Appendix 2.

In addition, some technologies that are not commercial now at current carbon prices (€25+/tCO_2 = £65+/tC) may become commercially viable at some future date if costs can be adequately reduced. It should be possible to estimate on the basis of learning curves and the productivity of RD&D which technologies it is worth investing in from a global point of view (through support to RD&D and underwriting deployment). There is a public good problem of financing this support (over and above the carbon contracts described above, which are commercial transactions that should be attractive to the Government if they are committed to future carbon prices remaining at a satisfactory level). The public good is a club good for the member countries who support the scheme (currently the EU, but ideally if Kyoto extends in time and coverage, to Annex I countries) and they need to find a mechanism for sharing the burden.

One such attractive method is to require each country to support some fraction of its total generation capacity (or output, to be decided) under each approved technology. A more flexible approach would allow some trade-off between technologies, reflecting their worthiness for support or the potential uncaptured external benefit arising from their support – so for example 1 MWh of wind generation might be deemed equivalent to 0.5 MWh of solar PV. The weights might be determined by the relative costs of support, i.e. the amount of capital subsidy per kW per year of the life-time of the capacity. Such support may take the form of green certificates which would be tradable, but ***it is important to choose a design for the support mechanism that is least-cost, and that means reducing unnecessary price risk and not necessarily granting all technologies equal support*** (as happens under the UK ROC system). Appendix 2 discusses some of the design implications and argues that at the EU level (and one would wish to see if this could be efficiently devolved to the country level) there would be tender auctions for capital subsidies for each technology, with relative reservation prices determined by an assessment of the size of the potential external benefit of the support). Butler and Neuhoff (2004) argue that the price certainty provided by feed-in tariffs in Germany has been far more cost-effective at stimulating the deployment of wind power there than the various riskier methods tried in the UK and there are useful lessons to be drawn from that.

Finally, at present nuclear power faces serious obstacles to efficient deployment. It does enjoy the benefit of the current ETS that raises the price of power generated by the cost of marginal CO_2 released, but as argued above, the durability of this benefit is in doubt. As discussed in the answer to Q3, UK Energy Policy needs a more efficient approach to nuclear siting, licensing, safety responsibility, decommissioning and waste management. At current long-term real interest rates, gas and carbon prices, nuclear power is economically very attractive, but the lack of long-term carbon and possibly electricity contracts somewhat reduces that attraction. The real show-stopper is, however, the lack of political commitment to resolving the regulatory hurdles (including waste–management) facing the industry.

On the demand side there are still various obstacles to improving energy efficiency of which the subsidies in the form of reduced rate VAT are one clear example, but the informational asymmetries discussed in section 2.5 above are also relevant. Standards for appliance and building energy efficiency are one standard solution to these. Improving the efficiency of the building stock may well be where the most cost-effective gains are to be reaped (although this would require a sound social-cost benefit test to confirm).

Q.2. *With the UK becoming a net energy importer and with big investments to be made over the next twenty years in generating capacity and networks, what further steps, if any, should the government take to develop our market framework for delivering reliable energy supplies? In particular, we invite views on the implications of increased dependence on gas imports.*

Security of supply decisions will be taken efficiently by the market only if scarcity is correctly priced and consumers anticipate future risks correctly. Ofgem is correcting the unsatisfactory nature of the balancing mechanism towards marginal pricing of imbalances and away from average pricing, and this should give clearer signals of scarcity, which in turn feed back into spot and contract electricity prices. Ensuring that suppliers are credit-worthy is important if they are not to avoid their financial risks by choosing bankruptcy. Gas storage investment decisions require an efficient intertemporal pricing of gas, which current oil-price linked contracts may fail to deliver (but see above at section 2.3). Such contracts are favoured by Gazprom and effectively undermine the security of local gas supply increasing dependence on Gazprom. There is thus a potential abuse of market power that may need corrective action if spot markets do not signal temporal scarcity properly (i.e. the price difference between winter and summer needs to earn a return on the cost of both the gas and the storage capacity, which has not been the case in the recent past). Long-term gas contracts with Norway ought to reduce dependence on Russian gas, as will the predicted increases in the share of LNG.

Retaining generation plant that is obsolete (coal and oil-fired in particular) to deal with gas shortages may be cheaper than providing gas storage, and a proper costing of emissions (sulphur in particular) should inform policy towards the implementation of the

Large Combustion Plant Directive (LCPD), as it may be preferable (cheaper) to keep coal and oil plant available even without Flue Gas Desulphurisation. ***The Government should consider whether to modify the application of the LCPD to power stations by introducing sulphur trading (as in the US) rather than subjecting each station to arbitrary limits (as under the LCPD)***.

Finally, there may be a case for reconsidering domestic franchises for gas and electricity (although this might require an EU decision to modify the Energy Directives, unless some other mechanism to make a single regulated regional supplier (perhaps chosen by auction) the obvious choice for an overwhelming share of domestic customers. Franchises provide the security that encourages long-term contracting that might support more diverse and secure investments (even in nuclear power, if the regulatory obstacles can be overcome). Certainly the REC franchises allowed considerable investments by IPPs in the 1990s. It is possible that the present structure of dominant and vertically integrated supply companies is an adequate substitute for reducing investment risks, even if it does so at higher cost for domestic consumers.

Q.3. *The Energy White Paper left open the option of nuclear new build. Are there particular considerations that should apply to nuclear as the government re-examines the issues bearing on new build, including long-term liabilities and waste management? If so, what are these, and how should the government address them?*

There are several actions that the government can take at low cost that considerably reduce the cost of exercising the nuclear option at some future date, such as providing assurances of stability of (and a intelligent design of) the safety and licensing regime, some way of reducing the cost of site approval, and of course assurance about (guaranteed contracts for) long-term liabilities and waste management, as well as longer-term assurances about the future price of carbon (as discussed in Appendix 2).

From the perspective of a nuclear power station design company (such as Areva-Framatome, Toshiba-Westinghouse or AECL Ltd) the United Kingdom appears to be a small and complicated market. There are larger and easier markets out there. None of these companies is fully familiar with the UK safety culture (in particular the *As Low As Reasonably Practicable* 'ALARP' approach); nor are they familiar with the workings of the HSE Nuclear Safety Directorate.[6] That Directorate is currently under-staffed and would appear unable to cope with multiple design approval applications. This is further complicated by the Government's somewhat ambiguous plans for "pre-licensing". As a consequence, the HSE-NSD is unlikely to be able to help a foreign design company familiarise itself with the UK safety regulation process anytime soon.

The UK has liberalised its electricity industry and has achieved competition. This is a good thing. At least four UK generators (British Energy, EdF, e-ON and RWE) currently

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[6] See Kemp (2005) for a discussion of the problems of created by the British approach to nuclear safety.

operate nuclear power plants perfectly safely somewhere in the European Union. How useful is that international experience in facilitating an efficient new build programme in the UK? Perhaps British Energy has a special advantage. We are not persuaded that nuclear power is so special that only one company should generate nuclear electricity in the UK. However, achieving a level competitive playing field for multiple nuclear generators, each perhaps seeking to build their preferred reactor type, seems especially complex given today's starting point.

The UK engineering base is comparatively weak and these international reactor technologies will struggle to source more than 50% of their design from UK companies. How does this affect the attractiveness of our market? At present in Europe and North America new build is only just starting and engineering firms are still keen to be given a chance. It is not unimaginable that in two years there will be a stampede towards nuclear power and the United Kingdom will struggle to attract interest from nuclear constructors.

We have companies capable of managing the complexities of project management for nuclear power plant construction, Amec and Bechtel come to mind. They appear to have a pivotal role in helping define the limits of the possible. We suggest that policy makers should examine the issues faced by all parts of the supply chain and establish an appropriate risk allocation. This is to be preferred to a strategy designed to assist the design companies or electricity generators. The whole question of where the responsibility for the design should rest may need rethinking and is an area that deserves careful analysis. Here the Treasury's approach is relevant: "the principle that should govern risk transfer in PFI projects is that risk should be allocated to whoever is best able to manage it. [. .] The aim is to achieve optimum risk allocation, not transfer for its own sake." (HM Treasury, 1995, §3.6 p13).

Nuclear power looks attractive at low rates of interest and current gas and carbon prices (or even projected prices reflecting lower gas prices). Figure 4 is reproduced from figure 16 of Roques, Newbery and Nuttall (2006) and shows the risk-return characteristics of three base-load generation technologies at a 5% real discount rate and a carbon price of £40/tC (SD £10), equivalent to a CO_2 price of £11/t CO_2 or rather lower than the price since last June).

With a 5% real discount rate, the nuclear plant Expected Net Present Value (EPNV) is much higher than the ENPV of a coal or CCGT plant, which are similar to each other. The relative riskiness of the three technologies has nuclear being less risky than gas and coal when only cost risk is taken into account, and the CCGT becoming much less risky to a merchant generating company than nuclear when both electricity price and gas price risks are taken into account, due to the high correlation of gas and electricity prices at present in the British market. Optimal portfolios when generators can obtain a long-term power purchase agreement contain a majority of nuclear power.

For a real discount rate of 8%, all three technologies still have positive ENPV and nuclear is less risky than gas and coal when only cost risk is taken into account (i.e. selling at a fixed price of electricity), but the CCGT is now much less risky to a merchant generator than nuclear when selling at the spot electricity price which is linked to (highly correlated with) the gas price. Clearly the economics of nuclear power depends sensitively on the discount rate and the nature of the electricity sales contract (which will depend on the degree of vertical integration of nuclear owning companies with retailing).

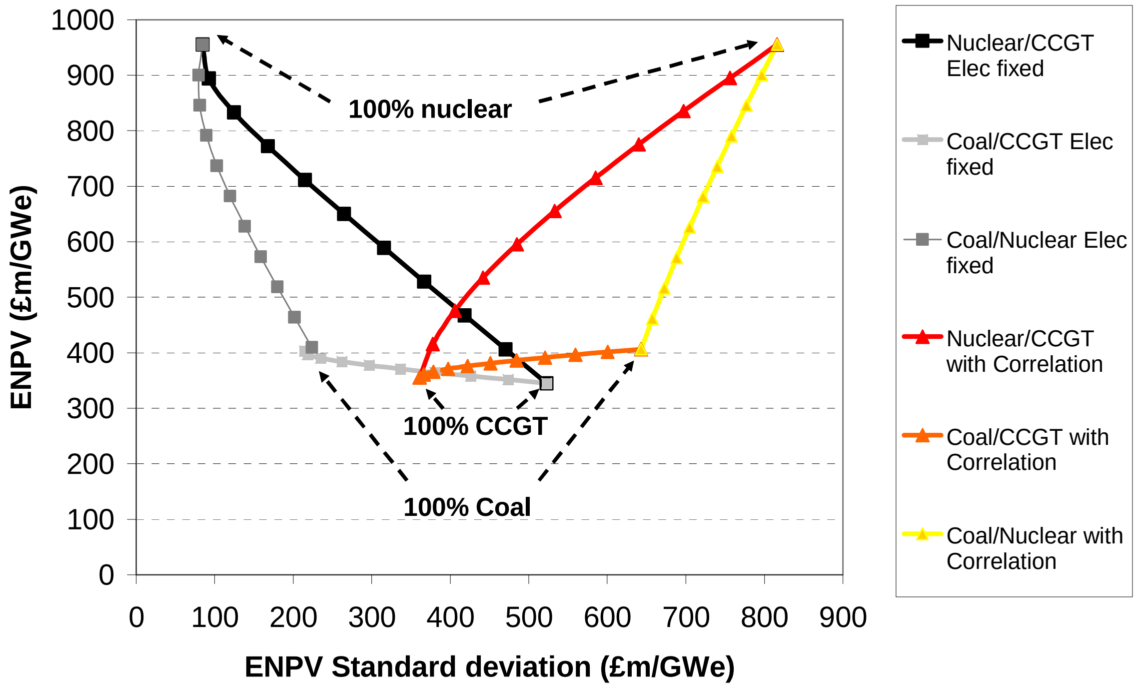

Figure 4 - Efficient frontier for portfolios of Nuclear, Coal and CCGT plants with *fixed and risky* electricity prices (*5% discount rate*)

One striking mismatch that suggests a possible market failure (or distortion) is in the current long-term risk-free interest rate (less than 2% for 30-50 years) and the commercial discount rate that is typically used to assess the economics of nuclear power. If companies were willing to take on the construction risk (which may be considerable), and if the Government could offer assurances against regulatory risk (site approval, licensing, safety and decommissioning), and if part of the capital could be raised by indexed bonds (perhaps even indexed to the electricity price)[7] perhaps secured by long-term contracts with consumers or suppliers, then the commercial case for new nuclear build would be considerably enhanced. (This would replicate the form of contract that the Finnish nuclear power station has with its backers who wish to use the power in their paper and pulp businesses and solves their problem of fixing the price of electricity).

Q.4. *Are there particular considerations that should apply to carbon abatement and other low-carbon technologies?*

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[7] As the French Government issued bonds indexed to the price of gold in the 1970s.

The proper design of policy towards low-carbon technologies requires efficient instruments to reflect future carbon prices to guide current investment decisions, and providing efficient, lower risk, support mechanisms for the RD&D aspects of low-C technologies that are not yet commercial even with carbon properly priced. They are discussed in Appendix 2.

Carbon abatement technologies, defined here as efforts to reduce emissions from fossil-fired generation, raise different questions. Indeed, it is unhelpful and misleading to place low-C technologies such as renewables and cleaner fossil generation in the same category for policy (and budgetary) purposes.

The case for carbon capture and storage (CCS) is strong enough to warrant serious Government attention on its own merit. Key considerations include: increased energy security; continued extraction of oil and gas from the North Sea (with the twin benefits to the Government of regional development and deferring the costs of decommissioning); and the magnitude of potential reductions in greenhouse gases from CCS, particularly in developing countries if the technology can be made commercially attractive.

If CCS technologies are seen to be cannibalising support for renewables, then support from environmental groups and the public may suffer, as has happened in Australia. Indeed, as the House of Commons Select Committee on Science and Technology has noted, a far greater effort of engagement with the public is needed on CCS (House of Commons, 2006 p. 43, para. 95). Given the early stage of development and relative lack of awareness, caution is warranted.

Until 2012, the emissions trading system (ETS), by itself, is unlikely to offer a carbon price sufficiently high enough to warrant significant investment in most carbon abatement technologies. According to House of Commons (2006) “For coal plant, the cost of avoided emissions compared with the plant which would be built today is £17/t CO_2 avoided.” This equates to about €29/EUA, slightly above the current level, and £63/tC, higher than DEFRA’s estimate of the (global) social cost of carbon. As with other long-lived and capital intensive low-C investments, if the UK is serious about demonstrating the viability of carbon abatement technologies, support mechanisms will be needed until a *long-term* carbon price mechanism is in place.

Unlike most other areas of the electricity sector, the UK has considerable expertise in the CCS in companies such as BP, Shell, Alstom, Mitsui Babcock, and AMEC. The UK also has the world-class British Geological Survey, which is already coordinating European efforts on geological storage. Based on historical ties, the UK is uniquely positioned to influence many of the major coal-consuming and exporting nations including the US, Australia, Canada, South Africa, and India.

In the short term, the focus of investment in carbon capture and storage technologies should be three-fold: large-scale demonstration in the UK, storage or enhanced oil recovery in the North Sea and cooperation in major emerging markets such as India, South Africa, and China. Each year, China adds (primarily coal-fired) generating capacity equivalent to total UK installed fossil capacity. Although the EU-China and UK-China memoranda of understanding are good first steps, they are still woefully inadequate given the magnitude and time pressures involved. Being able to influence the trajectories of China, India, South

Africa, and other developing countries with fast growth rates and domestic coal resources is thus of first order importance. Future involvement of key developing countries (and the US) in any international climate regime will undoubtedly be contingent upon addressing emissions from coal-fired generation.

If Britain seeks to maintain credibility as a leading advocate for carbon abatement technologies, it is incumbent to move beyond token efforts. The example of Sleipner in Norway has had a catalysing effect around the world in terms of generating media interest and broader notice. BP's DF-1 and other UK projects could have a similarly disproportionate effect at a time when many countries and firms are considering investments. The next obvious step would be support for demonstrating decarbonisation of coal plant (such as IGCC plus capture). RWE is already actively considering CCS for lignite plant in Germany and is involved in world-wide projects for CO_2 free steam plants (Platts, *EPD* 31 March 2006). Beyond direct support for specific capital investments, the only credible incentive for significant investment is a regulatory regime that offers long-term certainty (a time horizon of 20 years or more) as was the case for the US sulphur dioxide market.

Q.5 *What further steps should be taken towards meeting the government's goals for ensuring that every home is adequately and affordably heated?*

One possibly perverse implication of defining fuel poverty in terms of the fraction of household income spent on fuel is that it may inhibit an intelligent approach to domestic fuel taxation. Currently domestic gas use is heavily subsidised (it is not covered by the ETS and has a relative VAT subsidy of 12.5%) while electricity is covered by the ETS but also has a relative VAT subsidy of 12.5%. If, logically, these subsidies were removed (perhaps when energy prices start to fall, which is when Germany increased domestic energy taxes), then the numbers measured to be in fuel poverty would rise (or not fall). It would be better to target cash subsidies (or insulation services) on these households (like the winter fuel payment to pensioners) to compensate for the tax increase, and define fuel poverty net of these compensating transfers that offset fuel expenditures.[8]

One of the problems that increasing housing insulation standards encounters is that it raises the cost of building and buying houses, already the major expenditure facing most households. One would hope that new building standards are subject to cost-benefit analysis of life-time costs and savings and so in fact deliver cheaper household services than lower standard houses. Reforming the current very restrictive planning system that restricts the supply of land for building might do much to offset the cost increase in house building by lowering the price of land, encouraging a higher rate of turnover of the housing stock and hence a more rapid transition to a more energy efficient domestic sector.

[8] Thus if a household spends £1,200 on fuel and has an income of £11,000 it is defined as fuel poor (more than 10% of income spent on fuel). With a fuel subsidy (like the current winter fuel payment to pensioners) of £200 its relevant net fuel expenditure would fall to £1,000 taking it out of so-defined fuel poverty status.

Comments were also invited on the following issues:

i. *The long term potential of energy efficiency measures in the transport, residential, business and public sectors, and how best to achieve that potential;*

See answer to Q5 above, and note that transport fuel is overtaxed (as noted in section 1 above) and domestic heating fuel (except oil) is subsidised. Gas for domestic heating escapes the carbon price but electricity does not, which is perverse. There is little case for raising car fuel taxes which would inefficiently over-encourage costly increased fuel efficiency. Subjecting air travel to a sensible tax regime (rather than the current deeply inegalitarian fixed charge per passenger, not related to willingness to pay) would help. The first step is to argue that air travel be brought into the ETS and then to subject arriving flights to delivering the required number of EUAs, possibly modified by an additional greenhouse or global warming effects via contrails which are height-sensitive.[9] It may also be desirable to charge them for NO_x and other emissions where these are immediately damaging to human health – e.g. near ground level around airports.

ii. *Implications in the medium and long term for the transmission and distribution networks of significant new build in gas and electricity generation infrastructure*;

Distribution networks will need to become more actively managed and properly priced to guide efficient location decisions for distributed generation. Ofgem has consulted on how best to do this and we have responded (Jamasb et. al., 2005). Major investments in the grid are in danger of being inefficiently made if their cost is not properly attributed to the new connections (particularly in remote areas) causing the investments. Interruptible tariffs for access are required for some locations rather than the present guaranteed access in return for the annual access and TNUoS charges, so that generators are not compensated if they cannot be dispatched but do not have firm access rights, compensated for by a substantially lower charge (Neuhoff et al., 2006).

A more radical suggestion would be to replace the current system of grid charges with nodal pricing as implemented in the PJM market of the USA (Brunekreeft, Neuhoff and Newbery, 2005). Under the current electricity market design all generators are guaranteed firm access to the network and can sell their power at the same price regardless of any transmission constraints of the network. If the resulting electricity flows violate transmission constraints then the system operator National Grid must rebalance the system to relieve the congestion. The system operator bears some of the extra costs under the current incentive scheme, which in turn creates incentives for NG to minimise the connection of new generators who might contribute to congestion. Alternatively, connection of new generators is delayed until new lines are constructed. Intermittent renewables are quite likely to fall into

[9] Charging arriving flights means that their origin and hence fuel consumption is known, but charging departing flights to their first destination is also viable provided all covered countries make the same choice.

this category. Nodal pricing or non-firm access conditions could address this problem, or alternatively, the incentive scheme may need redesign.

iii. *Opportunities for more joint working with other countries on our energy policy goals*;

Joint working should play a critical part in UK Energy Policy to improve the effectiveness of our climate change policies, to leverage support for RD&D and to ensure competitive energy markets. Unless the UK believes that its actions and support activate comparable actions and support in the wider international community, they are almost certainly not worth doing. One mechanism that might encourage other countries to cooperate in burden sharing might be a border tax on the carbon content of imports from non-Kyoto signatories, or those who do not impose carbon taxes or charges. Ismer and Neuhoff (2004) argue that this would be legal under the WTO and potentially quite effective.

In Europe, the main task of the UK Government is to first identify market failures that can be corrected and work to correct them so markets can work, and concentrate international attention where collective action is needed – critically on climate change action and burden sharing for low-C RD&D support. The present system of allocating EUAs introduces unnecessary distortions in the operation of and investment in power stations, as discussed in Appendix 3, while supporting large income transfers from consumers to electricity generating companies, both of which undermine support for the ETS, and threaten its continued existence. The UK could also play a helpful role in ensuring that actions are intelligently targeted and justified by proper cost-benefit analysis. Finally, the UK should continue to press for more competitive energy markets, and resist the thrust towards national champions, while supporting countervailing power against external monopolies in gas.

iv. *Potential measures to help bring forward technologies to replace fossil fuels in transport and heat generation in the medium and long term.*

Here the danger is to pursue options that are likely to be uneconomic or better developed elsewhere. Over the longer term, the key drivers for replacing fossil fuels in transport and heat generation will be expanded support for RD&D and the continued growth in carbon prices commensurate with longer-term reductions in emissions, but not all technology or fuel options are equally attractive. The hydrogen economy will require sustained research over many decades and will face many challenges. The danger with bio-fuels is that they will become a cloak for more inefficient farm subsidies, and should not be offered without free import rights for the raw and processed products (e.g. sugar, ethanol and bio-diesel). The best way to subsidise bio-fuels is to reduce the road fuel excise tax by an estimate of the value of the CO_2 saved as measured by the ETS. It is not clear that there are many learning-by-doing externalities that need further subsidy, as the UK's addition to the world total of bio-fuel consumption would be tiny. Road transport is already over-taxed, while air travel is subject to an inefficient charge per passenger, rather than on the global warming impact of the flight.

There is a danger that walking and cycling solutions will be overlooked as these are delegated to often-hostile local authorities that may see motorists and public transport as their main constituencies. The UK should aim to imitate the Dutch approach to supporting cycling. Better cost-benefit of public transport is needed to eliminate hugely inefficient (in cash and emissions terms) lightly used rail routes, concentrating instead on increasing capacity cheaply on heavily used commuter lines (relax station length requirements to allow longer trains, better pricing of train access to give preference to heavily used services, etc).

Decentralised gas-fired micro-generation is already subsidised by the restriction of the carbon charge to electricity generation, although support for deployment and demonstration may be justified. Scepticism is in order for CHP schemes for housing unless they are designed as part of high density new build, and even then they need to be subject to critical cost-benefit analysis compared to decentralised heating and better insulation.

Appendix 1 The Emissions Trading System and its impact on electricity prices and the exercise of market power in the gas market

Figure A1 shows the evolution of carbon prices since trading started in the ETS (actually of CO_2 measured by the price of EUAs, which must be multiplied by 3.67 to give the price of carbon per tonne).

EUA price 25 October 2004-28 March 2006

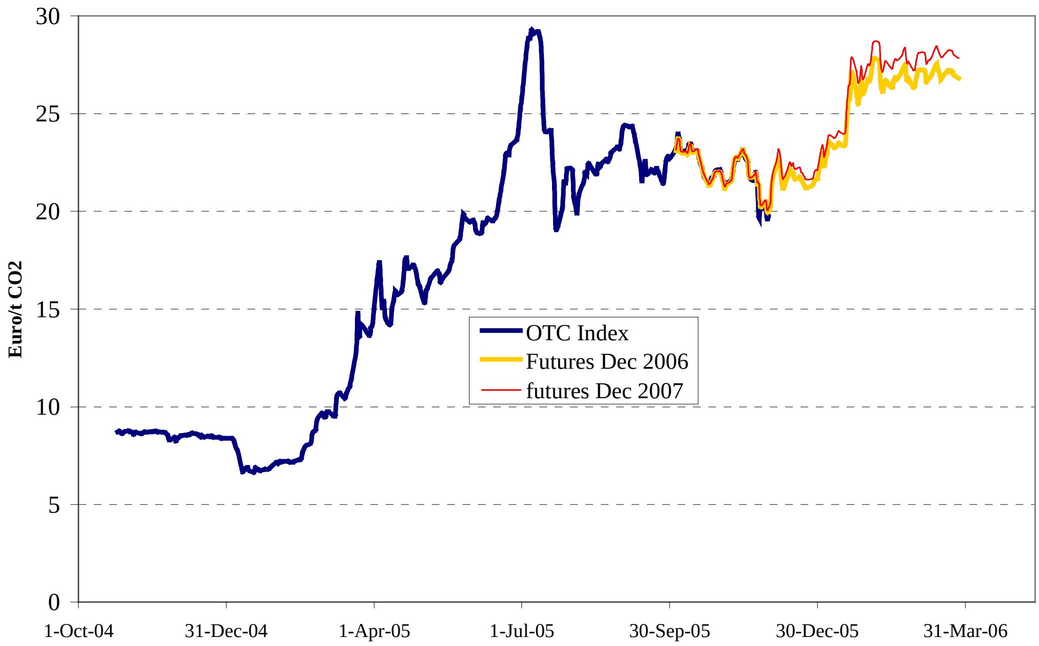

Figure A1 Price of CO_2 in Euros/tonne (Source EEX)

The price appears now to be above €25/tonne CO_2 or \$110/tC (£63/tC), well above most estimates of the global social cost of carbon, which might lie in the range \$8-53/tC (Newbery, 2005b, using figures from Karp and Zhang, 2004), or the rather higher figures used by DEFRA of £35/tC.[10] Hope (2005) estimates a figure of \$66/tC (£45/tC) using IPCC's data and \$43/tC (£30/tC) using more plausible equity weights.[11] Both figures have wide

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[10] http://www.defra.gov.uk/environment/climatechange/carboncost/index.htm

[11] Hope's model weights outcomes according to a social welfare function, whose central equity value $\nu = 1$ gives a marginal utility weight inversely proportional to income. This equity weight directly affects both the discount rate r (according to the formula $r = \nu g + \delta$, where δ is the rate of pure time preference and g is the per capita real rate of growth of consumption) and the weight attached to damage to low income countries. If one wished to attach a more uniform weight to damage to poor countries (i.e. use a lower value of ν for cross-country equity purposes) while retaining a higher value of ν for inter-temporal decisions within the UK or EU, then the effect can be simulated by raising δ and lowering ν, both of which reduce the SCC. The figure of \$43/tC compared to \$66/tC represents the effect of increasing δ from 1.5% (as in the *Green Book*) to 2% and the mean rate of discount from 3.5% to 4%. Lowering δ and the cross-country equity weight would have roughly offsetting effects.

confidence intervals (16% to 300% of the central estimate covers from 5% to 95% of the probability distribution of outcomes).

Evidence that the EUA price does indeed feed through to the wholesale price is provided by figure A2, which shows the spark spread in various markets and the cost of the CO_2 emitted per MWh of electricity produced in a combined cycle gas turbine (CCGT) of 50% efficiency. (The spark spread is the base-load price of electricity for the month ahead *less* the cost of the gas needed at 50% efficiency to generate that electricity, and is a measure of the gross profit needed to cover fixed and capital costs of generation).

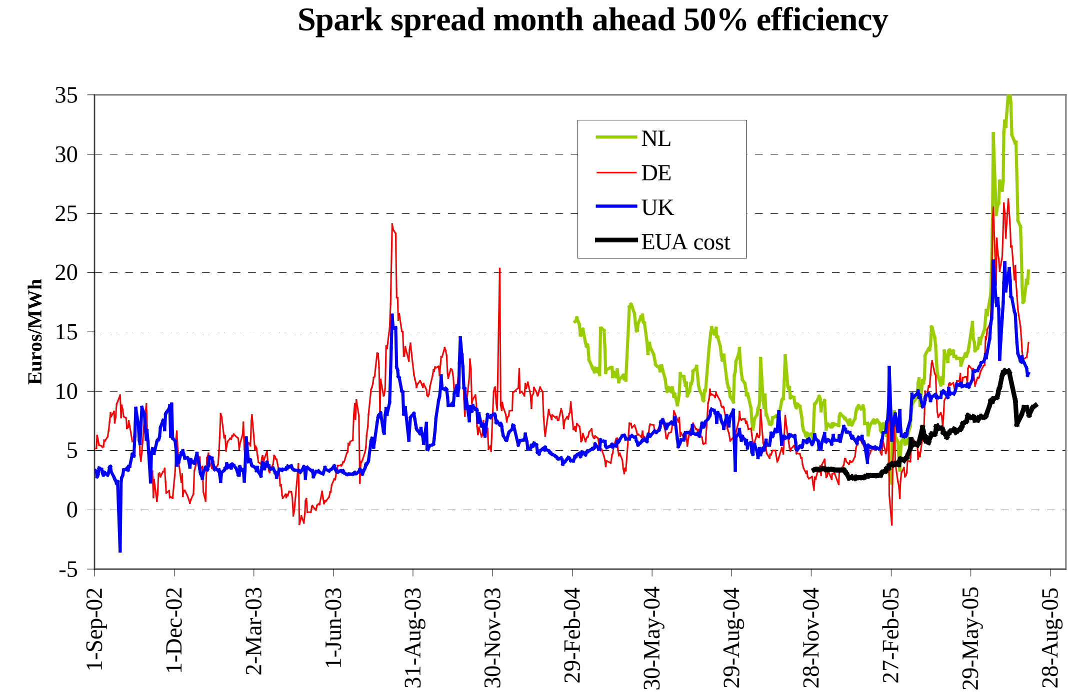

Figure A2 Spark spread and carbon cost in various EU markets (Source Platts)

The impact on wholesale prices of the obligation to provide EUAs equal to the emissions from 1 January 2005 is shown by subtracting their opportunity cost from the spark spread in figure A3 to give a "clean spark spread". After an initial period of adjustment the gross profit margin has returned to where it had been before the ETS, suggesting that most if not all of the EUA opportunity cost has been passed through into the wholesale price.

The price of EUAs is determined by supply and demand, and both depend on the extent to which the electricity supply industry can substitute less carbon-intensive fuels like gas for more carbon-intensive fuels like coal though changes in the merit order. As the price of carbon increases, so gas becomes more attractive relative to coal and gas demand will increase, reducing the need for EUAs. More to the present point, as the price of gas increases, the value of EUAs increases, as the demand from coal-fired generation will increase demand for EUAs, raising their price, and hence making gas relatively more attractive. The effect of the ETS is thus to make the demand for gas more inelastic (i.e. the demand will become less sensitive to its price).

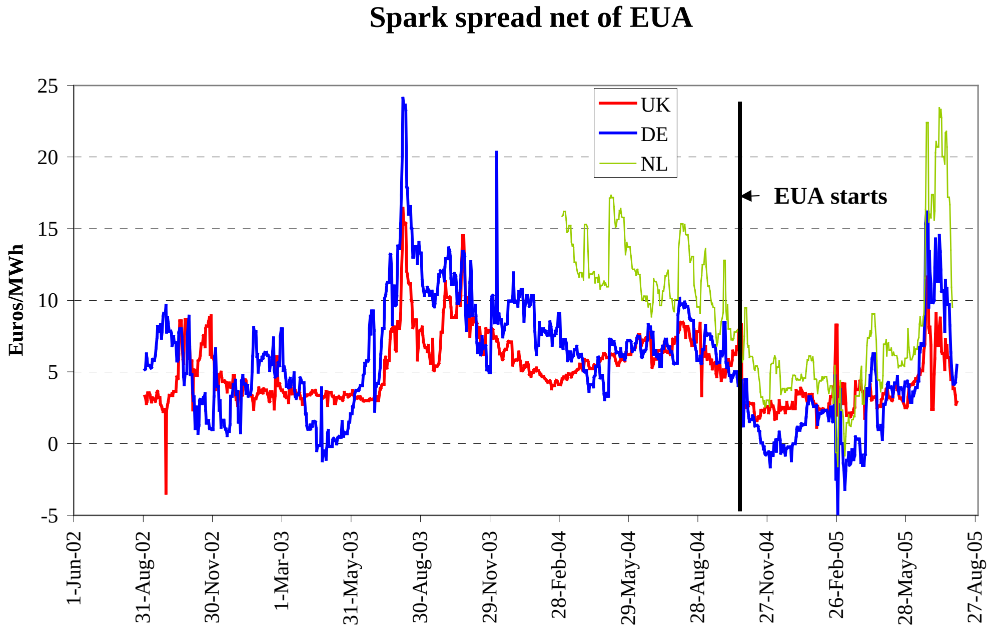

Figure A3 Gross profit of CCGT after paying for fuel and carbon (Source: Platts)

While the international market for coal is reasonably competitive, the same is not true for gas, particularly in Europe, which is heavily dependent on importing Russian gas from the monopoly supplier, Gazprom. In addition, gas producers and suppliers in the EU have more market power than the suppliers of other fuels, and are frequently vertically integrated into electricity generation. There are therefore grounds for concern that the particular way climate change policy works in the EU through pricing a fixed supply of EUAs amplifies the existing market power in the gas market by making gas demand less elastic and price sensitive. This in turn enhances the market power of those selling gas, including large foreign suppliers such as Gazprom. Estimates presented in Newbery (2005b) suggest that the effect could be to increase market power measured by the Lerner Index (the markup as a fraction of the price) by up to 50%.

If the price of EUAs were stabilised (by banking or issuing and removing permits at a fixed price) then the link between the demand for gas and the price of EUAs would be broken and the market power of gas suppliers would no longer be amplified.

Appendix 2 The case for long-term carbon contracts and better instruments to support new technologies

The economics of low-C generation technologies depend on the future price of carbon, which is completely uncertain after 2012. A prudent investor will thus heavily discount the benefits of earning the carbon premium in the electricity price (currently visible in the number of EUAs needed to generate the marginal MWh of electricity, as discussed in Appendix 1). One mechanism that might help reduce this bias is for the Government to offer low-carbon technologies an option on a contract for differences for future carbon prices (a CfDC). These would set a strike price for CO_2 (£2006/tonne CO_2 at each year from a specified future date, *T*, to *T*+15). For example, the CfDC may specify a strike price of £10/t CO_2 indexed to the RPI at Jan 1 2006, for the period 2012 to 2027). A potential investor in low-C generation may bid now at an annual auction (or pay a price computed by an option valuer) for the right to take up 5 million CfDCs (each of 1 tonne CO_2 and enough to hedge 1000 MW of base-load coal plant) with this strike price at the start of its exercise (in this case 2012). If the CO_2 price fell below £10 (e.g. because the ETS collapsed, or now longer applied to electricity generation, or was replaced by some other scheme that led to a lower effective price of carbon embodied in electricity) then the Government would pay the shortfall from £10, but would receive any excess above this level. The option would be denied if the holder did not have a credible way of delivering low carbon electricity at or shortly after the due date, and would be restricted to owners of low carbon technologies (specified as less than e.g. 0.1 t CO_2/MWhe released).

The main complication with this is establishing the effective carbon price embodied in electricity prices if the ETS is modified or overlaid by other instruments that reflect the cost of carbon. Given that extremely large sums of money may hinge on this (in the case discussed, if the actual carbon price were £5/t CO_2 the transfer to the holder would be £35 million per year), the difficulty should not be under-estimated.

Given that, it may be preferable for the Government to offer CfDs written on the price of electricity (CfDEs), which is in any case a more direct hedge against both future high or low fuel as well as carbon prices. The exact form of the CfD would need careful design, and at this stage only suggestions can be made. One such is to define the CfD on a capacity payment (£k/MW/hr available) and an energy payment (£p/MWh generated). At the end of the year if the plant had sold Q MWh for revenue R at an average availability factor of a (e.g. 80%), the Government would pay $8760.ak + pQ - R$, which might be negative, indicating that the generator would pay the excess to the Government.

Instruments for supporting new technologies

The main instrument for supporting renewables in the UK are Renewable Obligation Certificates (ROCs), which have the obvious drawback that their price fluctuates with supply and demand, and hence is risky, to the point that the price of eligible generation seems to discount the rather high potential ROC income heavily after a few years (Butler and Neuhoff, 2005). It would reduce risk if instead new technologies were offered a fixed price for generation rather than facing a variable and unpredictable price. The logical solution to subsidising the deployment of capital-intensive but low variable cost technologies is for a tender auction for capacity subsidies (combined with the CfDCs or CfDEs described above).

It may be preferable to pay this subsidy annually per kW of capacity actually available spread over a certain number of years (e.g. 15 years to ensure adequate durability and maintenance, particularly important for e.g. off-shore tidal or wave power, but predictable to allow borrowing against the payment obligation). To avoid a lack of commitment on the part of those bidding for the subsidy, the payment would be contingent on delivery by an agreed date with a penalty for non-delivery for each of a number of subsequent years (e.g. 3 years, to allow for some slippage but not abandonment). The experience of the earlier NOFFO auctions suggests that this might be important, and some care should be taken to devise an efficient auction design, and whether it is better to subsidise capital or generation or some surrogate such as availability.

An alternative is to invite tenders for a fixed price feed-in tariff, which automatically addresses the issues of the carbon benefit and continued availability, but does not reward generation for availability in peak value hours. This may not be a serious objection for low variable cost plant, which will benefit from being available as much as possible, but it may complicate dispatch instructions in constrained export zones where the renewables competes directly with high marginal cost plant. Non-firm connection agreements or other dispatch arrangements can be offered as options in the tender auction, and the least cost solution (including dispatch and transmission investment costs) can then be chosen.

With such a support system, there would be no need for ROCs or feed-in tariffs as well, and a need if they are retained to ensure that they are not more costly forms of delivering the same result, as well as a need to continue existing rights or transfer them into an equivalently valuable system of support that does not require their continuance. Here the obvious choice is to capitalise the expected future value of ROCs assuming no change in support as a subsidy to be paid per kWh generated, perhaps to be determined in a tender auction. There would be a reservation ceiling in this auction, with those whose bids were not accepted being compensated by the implied value of ROCs given the actual volume of renewable electricity generated. This is likely to be higher than under the ROC-only scheme as this mechanism should deliver more renewables at the same subsidy cost, and so the predicted market clearing price of ROCs will be lower, encouraging a tender at or below the ceiling, which itself would be set to be non-expropriatory.

Appendix 3 The design of allocations mechanisms and updating

Karsten Neuhoff

The first point to make is that the price of EUAs is already passed through in higher electricity prices (as argued in Appendix 1) and to that extent free allocations of EUAs to electricity companies is a pure windfall gain translated into higher profits (at the expense of other possible uses of that income, e.g. in financing increased energy efficiency, offsetting the impact on electricity consumers, etc.). The past allocation decisions were agreed with the EU and cannot be changed, but the future of allocations is an important issue for UK (and even more EU) energy policy. The critical question is how future allocations should be made.

The iterative allocation of allowances to power stations means that today's production of the power station is likely to enter the base line of (and thus affect) future allocations. This effect is typically referred to as 'updating'. To avoid the resulting perverse incentives, governments aim to commit not to implement such updating. It is, however, difficult to envisage that a government in 2011 will allocate allowances worth hundreds of millions of Euro to power stations based upon their pre-2005 existence even if the power station has subsequently been closed down, at least without distinguishing between entitlements as a function of some objective measure of life expectancy.[12]

As a result, expectations about contingent entitlements to future allocation create an economic incentive to keep open obsolete power stations. This has a number of effects. More power stations connected to the power system reduces the scarcity value of generation capacity and discourages investment in new and more efficient replacement power stations. More old and carbon-intensive power stations also increase CO_2 emissions, thus increasing the scarcity value of CO_2 allowances and pushing up electricity prices. While the net impact upon electricity prices depends upon the specific scenario, both distortions create inefficiencies (in the choice of investments and the operation of power plants). Figure A4 illustrates some of these distortions.

Allocation plans not only have to determine if, but also how many, allowances are allocated to individual power stations. Five basic approaches can be used to determine the quantity of allowances allocated to a power station. Sorted according to increasing severity of the distortions created, they are based upon: (1) installed capacity, (2) installed capacity and fuel type (3) historic power generation, also referred to as uniform benchmarking (4) historic power generation and fuel type, also referred to as fuel specific benchmarking and (5) historic emissions.

The following effects are present in some of these allocation methods:

a) The fuel or emission specific components of methods (2), (4) and (5) create additional incentives to retain generators with C-intensive technologies available. This in turn can increase CO_2 emissions, CO_2 scarcity prices and feed through to higher electricity prices and higher costs of CO_2 emission reductions.

[12] These would depend on age, fuel and thermal efficiency

b) The updating effect of methods (3) to (5) implies that generators in competitive environments reduce the price at which they sell electricity by the value of future allowances they expect to receive. This might feed through to lower electricity prices. However, this direct effect might be partially compensated: if lower electricity prices induce additional electricity consumption and production, then higher CO_2 emissions might increase the CO_2 price.

c) The fuel-specific updating effect in methods (4) and (5) creates additional incentives to operate CO_2-intensive power generators and thus increases CO_2 emissions. Given the constraint on total CO_2 emissions, this pushes up the CO_2 allowance price, which then feeds through to higher electricity prices.

d) The emissions-related updating effect in method (5) reduces the incentive to improve the fuel and CO_2 efficiencies of existing power stations, and thereby increases CO_2 emissions, allowance prices and electricity prices.

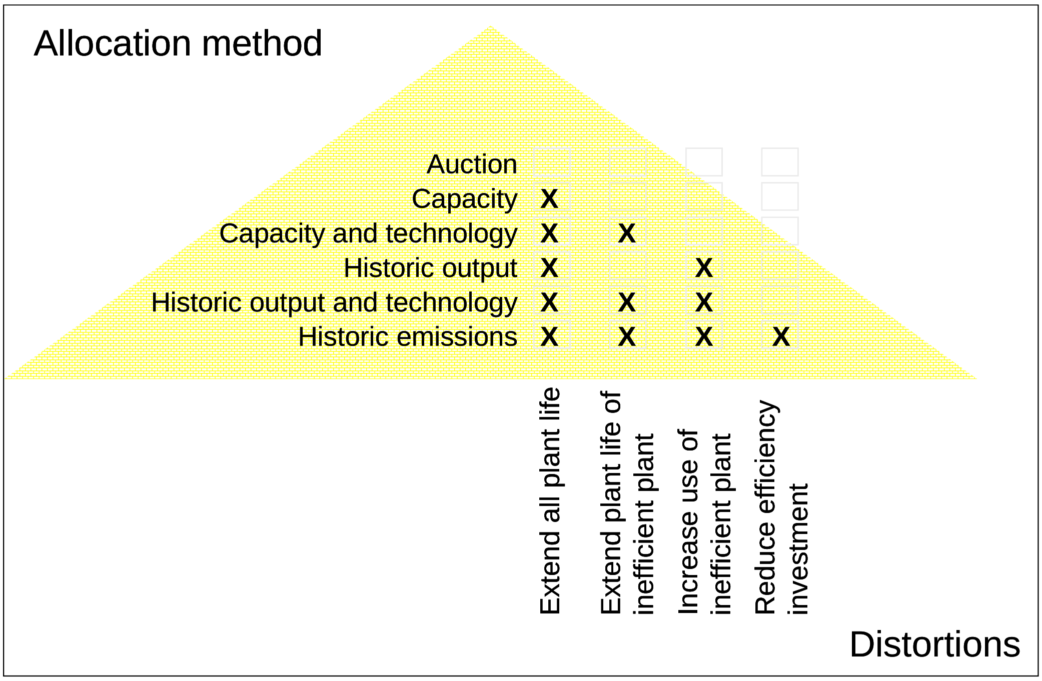

Figure A4 Distortions from allocations to existing plants

Effect (b) might directly feed through to lower current electricity prices. Whether this effect dominates the price increases induced by the other effects depends both upon the allocation method and the specific circumstances. Irrespective of the direct impact upon the electricity price, all distortions create inefficiencies that increase the aggregate cost of CO_2 emission reductions.

Finally, all national allocation plans envisage some allocation of free allowances to new power stations (new entrants' allocation). These provisions are motivated by a combination of: (1) national industry policy aiming to attract new investment, (2) an attempt to compensate for distortions created by closure provisions and (3) the objective of facilitating the finance of these assets by reducing the required capital and risk exposure. The free allocation to new entrants can again create various distortions of the market.

From our analysis, we conclude that the following principles should guide future allocation policy:

- phase out free allocation as quickly as possible; failing which
- avoid the most distorting effects of the free allocation;
- create institutional independence for the allocation process ;
- clearly identify the objectives of the free allocation, e.g. compensation of costs of emission trading, and avoid creating uncertainty by aiming to satisfy too many policy objectives using the allocation process;
- support the European Commission in enforcing such objectives, as individual member states might pursue allocation methods that benefit national electricity prices or industry at the expense of higher European CO_2 prices. (If the UK over-achieves its targets, it will be able to sell surplus EUAs more profitably if other countries raise EUA prices by inefficient strategies, but this will tend to weaken commitment to the Kyoto process within Europe.)
- Outline a credible post 2012 strategy to create investment security.

The first step in addressing these distortions might be to define a time path of reducing allocations to existing stations that is independent of whether they continue operations or not, based on their age, efficiency and fuel. This would be simpler if new stations were not eligible for allocations, for then major upgrades would not change these allocation rules, otherwise upgrades might argue for equal treatment with new investment. For example, CCGT stations might be defined to have a nominal 20 year life, oil and coal-fired stations of above 33% original achieved thermal efficiency a 30 year life (and below that, no life beyond the earliest relevant date, e.g. 2008), and nuclear and hydro stations a 30 year life, all from date of commissioning, with the percentage of base-line allocations declining to zero at these dates. A CCGT station commissioned in January 1993 and with currently a 95% base-line allocation, would in 2008 be granted 5/20 x 95% of base-line EUAs, falling to zero in 2013. A coal-fired station commissioned in January 1978 would receive nothing.

Adjusting the nominal lives or the date at which this scheme came into effect would allow different transfer payments to the electricity industry without affecting the prices of electricity, bearing in mind that any allocation represents an almost pure windfall gain to electricity companies (paid for by electricity consumers). To the extent that fewer EUAs are need for allocation to existing and new power stations, the balance could be auctioned, generating additional public funds to finance RD&D, efficiency investments and to compensate consumers and sectors adversely affected by international competition from countries not covered by stringent emissions policies.

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[13] EPRG papers can be downloaded from http://www.electricitypolicy.org.uk/ as can *DTI 2006 Energy Review - Relevant EPRG publications* that provides abstracts of these and other papers.