Climate Change Policy and its Effect on Market Power in the Gas Market

David M. Newbery

February 2006

Climate change policy and its effect on market power in the gas market

David Newbery[*]

Faculty of Economics, Cambridge

16 November 2005

(revised 3 July 2007)

accepted for publication in the *Journal of the European Economic Association*

Note: the earlier version of this paper is appended at the end.

Abstract

The European Emissions Trading Scheme (ETS) limits CO_2 emissions from covered sectors, especially electricity (accounting for about 56%). At €44 billion p.a. the ETS is the largest emissions trading system ever, 40 times larger than US programmes. The paper demonstrates that fixing the quantity rather than the price of carbon reduces the price elasticity of demand for gas appreciably, amplifying the market power of gas suppliers, and amplifying the impact of gas price increases on the electricity price. A rough estimate using British data suggests that this could increase the Lerner index by 50%.

Key words

Climate change, emissions trading, market power, gas, quotas vs taxes, Lerner index

JEL classification

Q54, Q58, L94

CLIMATE CHANGE POLICY AND ITS EFFECT ON MARKET POWER IN THE GAS MARKET

David M Newbery[*]

Faculty of Economics, Cambridge

Abstract

The European Emissions Trading Scheme (ETS) limits CO_2 emissions from covered sectors, especially electricity (accounting for about 56%). At €44 billion p.a. the ETS is the largest emissions trading system ever, 40 times larger than US programs. The paper demonstrates that fixing the quantity rather than the price of carbon reduces the price elasticity of demand for gas appreciably, amplifying the market power of gas suppliers, and amplifying the impact of gas price increases on the electricity price. A rough estimate using British data suggests that this could increase the Lerner index by 50%.

1. Introduction

The European Union has agreed the European Emissions Trading Scheme (ETS) as its principle means of reducing emissions of the main greenhouse gas (GHG), carbon dioxide, CO_2. The ETS fixes the quantity of CO_2 that can be emitted from the covered sector, and can be contrasted with the alternative, and as argued below, preferable policy of taxing or setting a charge for the release of CO_2. More than half (56%) of emissions from the covered sector come from the electricity supply industry (ESI, i.e. electricity generation), and in the EU in 2004, 31% of electricity was generated from coal, and 19% from gas. Nuclear, hydro and renewables, all zero-carbon sources, accounted for 46% of total generation (IEA, 2006, p507). For the EU-15 the share of gas is higher at 21% and of coal lower at 27%. The zero carbon generation is inelastically supplied over the course of the year, as it has very low variable costs, but coal, which is very carbon-intensive, competes with gas-fired generation, which has half or less coal's carbon intensity.

This paper will argue that the fact that the ETS is a quota system amplifies the existing market power of gas suppliers, provided the allowances are scarce (as is the intention of the ETS). If the price of gas increases, electricity generators will switch some generation from gas-fired to coal-fired plant, increasing CO_2 emissions. Because the quantity of CO_2 allowances is fixed, an increase in their demand raises their price. The immediate effect is to magnify the impact of a gas price rise on the price of electricity, which is hard to reconcile with the environmental objectives of the ETS.

The second effect of raising the CO_2 price is to raise the cost of generating electricity from coal by more than it raises the cost of gas-fired generation. The rise in CO_2 price partly offsets the original decrease in gas demand caused by the gas price increase, and hence reduces the elasticity of demand for gas compared to a world in which the price of CO_2 is fixed. The market power of gas suppliers, measured by the Lerner Index, i.e. the ratio of the price-cost margin to the price, is inversely proportional to the elasticity of residual demand facing the suppliers,[1] so a reduction in the elasticity will increase the mark-up of gas costs, amplifying their market power.

At a more fundamental level, this effect is an example of the Samuelson-Le Chatelier principle that constraints on any part of a general equilibrium system (such as a market economy) reduce the elasticity of response of the unconstrained elements of that system (Samuelson, 1947). In this case a constraint on the amount of CO_2 available reduces the elasticity of demand for gas, just as quotas on imports of goods reduce the demand elasticity facing domestic producers and allow them to leverage their market power (Bhagwati, 1965).

To demonstrate the possibility and significance of this claim, it is necessary to show first that gas and coal-fired generation are substitutable and respond to changes in the price of gas relative to coal, second, that the price of CO_2 is material in influencing the choice of fuel, third, that price of EU Emission Allowances feeds through to the price of electricity and hence has a direct effect on consumers, fourth, that the gas market is imperfectly competitive, fifth, that the effect on gas market power is material, and finally, that the social cost of the results further strengthen the existing case for stabilising the price of CO_2 (and other GHGs) rather than fixing the quantity of emissions.

2. The EU Emissions Trading System

The ETS fixes the quantity of CO_2 that can be emitted from the covered sector. Each year from 2005 until the end of 2007 each country allocates at least 95% of its overall allowances to eligible firms, who are then free to trade them within the EU. EU-wide demand and supply of EUAs determine the resulting price of an EU Emission Allowance (EUA) for 1 tonne of CO_2. At the end of each calendar year covered industries, of which the largest is the electricity supply industry (accounting for about 56% of the total), must deliver EUAs equal in total to their recorded emissions in that year. EUAs can be held until the end of 2007, at which point a new scheme starts. The old EUAs then become worthless, and from 2008 until the end of 2112, second period EUAs are required. Figure 1 shows the spot and futures prices for first period EUAs, and recent futures for 2008 delivery of second period EUAs.

There are several points to make about the ETS. First, it represents a step change in the size of emissions markets, for the number of EUAs issued each year for the EU as a whole is around 2.2 billion, which at a price of €20/EUA gives a value of about €44 billion per year. In contrast the US cap-and-trade programme for SO_2 issues annual allowances for just under 3 million tons, which at 400 €/tonne SO_2 gives an annual value of around €1.2 billion. The US

---

[1] This relationship holds for Nash equilibria in supply functions (as derived by Klemperer and Meyer, 1989 and applied to modeling wholesale electricity markets by Green and Newbery, 1992), and in

NOx cap-and trade programme that initially covered the North-eastern states issued 143,000 tons of allowances in 2003 which at $750/ton gives a market value of about $100 million, although this is for only part of the US.[2] The ETS is therefore nearly 40 times the value of the previous largest emissions trading programme.

EUA price 25 October 2004-30 March 2007
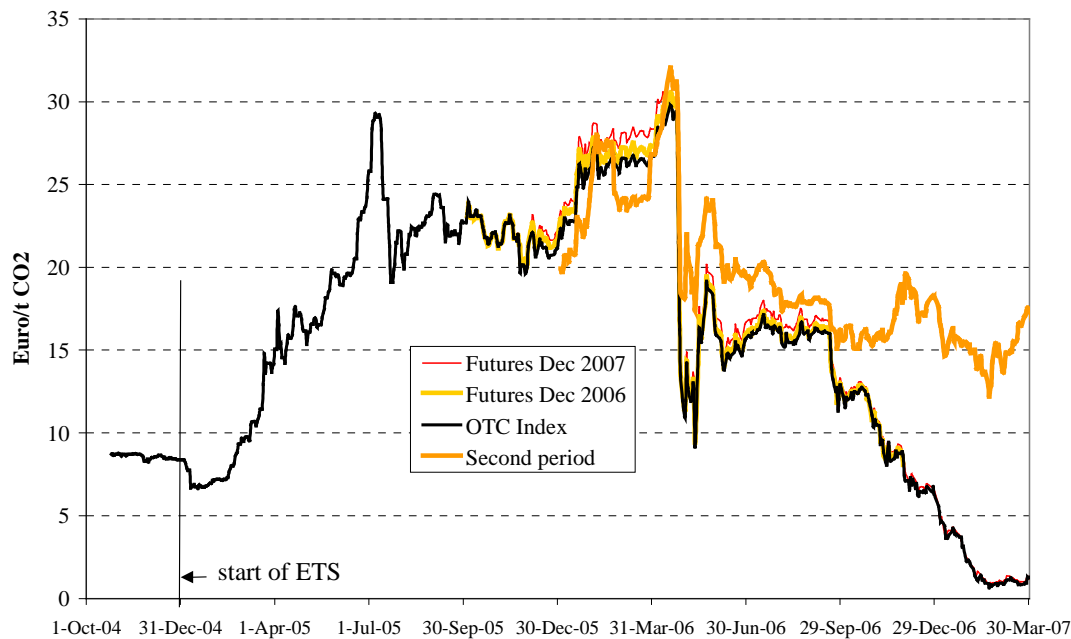
Figure 1 The prices of EUAs valid for 2005-2008
Source: EEX carbon index

Second, the prices of spot and futures *within* each trading period (until 31 Dec 2007, and 1 Jan 2008-31 Dec 2012) moved very closely together. Thus prices for EUAs for each successive year's delivery from Dec 2008 increase by 2.5% (SD 1.1%). Third, the prices of second period EUAs (the Kyoto commitment period) start below the first period price, but after March 2006 rise above it, and thereafter movements in the two series are significantly different. Ellerman and Parsons (2006) suggest that relative movements in prices give an estimate of the probability of a shortage of first period EUAs by the end of that period. The collapse of the first period market in 2007 reflects the growing realisation that the emission constraint had been set too leniently in the first period. In response the European Commission has been tougher in cutting back National Allocation Plans for the second period, sustaining a higher price of around €15/EUA (about $74/tonne of carbon). Finally, the market for EUAs has been volatile, as Figure 1 shows.

Cournot Nash equilibria.
[2] US EPA (2003). Each year the volume of allowances decreases.

2.1   *Substitutability between coal and gas in electricity generation*

The first piece of evidence needed is the relevance of coal-gas substitution. This depends on the prices of both coal and gas, for most countries have spare oil-fired capacity that is uneconomic except during very high price periods, and so is hardly involved in any price-sensitive substitution. Britain has the most readily accessible relevant information about fuel costs used in generation, as DTI (2007) gives the prices paid by major generators for coal and gas. Figure 2 plots the quarterly average prices paid for coal and gas before the start of the ETS (shown as triangles), after the start with (diamonds), and without (squares), the cost of the EUAs required to burn that fuel.

**Fuel choices in UK electricity generation**
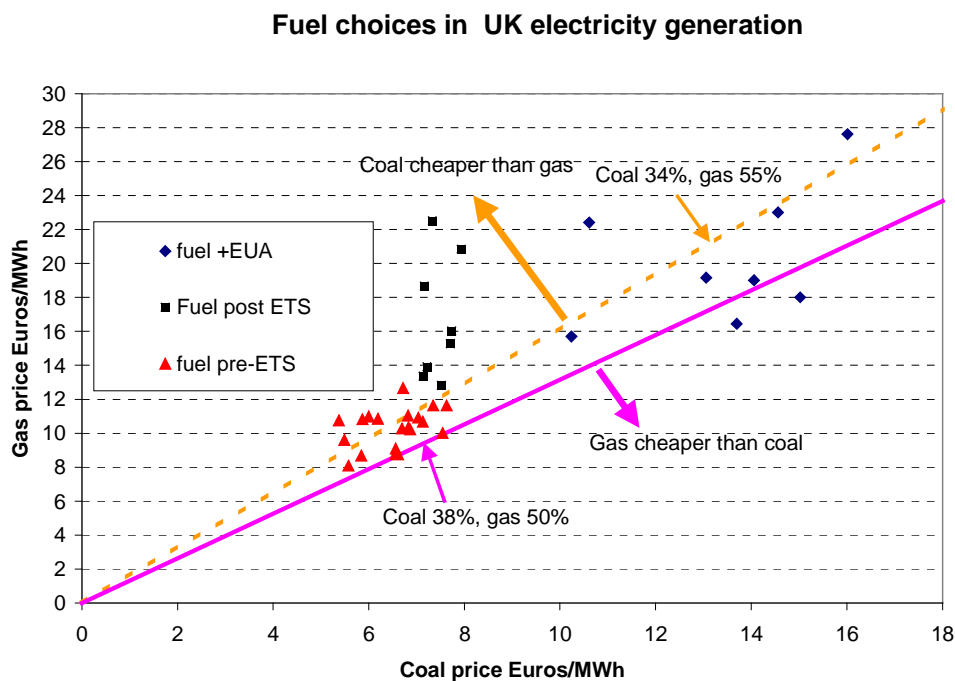
Figure 2 Costs of fuel used by major UK electricity generators, 2000-2006
Source: DTI (2007)

The lines represent combinations of the prices of coal and gas that would make the fuel cost of generation from coal and gas equal, for different combinations of efficiency in generation. Thus if coal-fired generation is 34% efficient, but gas-fired generation 55% efficient (Platt's assumed efficiency for quoting fuel costs) the upper dotted line is relevant, but if coal is more efficient (38%) and gas less efficient (50%, roughly the British averages), then the lower bold line is relevant. Above the line coal-fired generation is cheaper than gas, while below gas is cheaper than coal. Note that, depending on efficiencies, gas and coal are frequently competitive before ETS, but they would only be competitive after ETS with the cost of EUAs added. The evidence suggests that coal and gas are indeed competitive against each other and that the ETS has been decisive in keeping gas competitive with coal as gas prices increased. Further evidence is to be found by comparing daily spot gas prices (at the National Balancing Point, or NBP) against the quarterly DTI coal figures. For the post-ETS period without the cost of EUAs, gas is cheaper than coal 4% of the days on the lower

criterion (gas at 50% efficiency) and 11% on the Platts definition, but with the cost of EUAs it is cheaper 24%-65% of the time.

The next question is whether coal does displace gas as the price of gas rises. Here the evidence is extensive and compelling. Figure 3 shows the daily price of gas (the stepped function) rising sharply over the period 1 November 2005 to later in that month, and the output of coal-fired and gas-fired electricity in Britain (on an hourly basis but graphed as a 24 hour moving average). As the price of gas rises, so the amount of coal burned increases and gas decreases (and the considerable increase in overall demand is met by coal, rather than gas).

Weekday moving 24 hr av coal and gas generation Britain 1 Oct-9 Dec 05
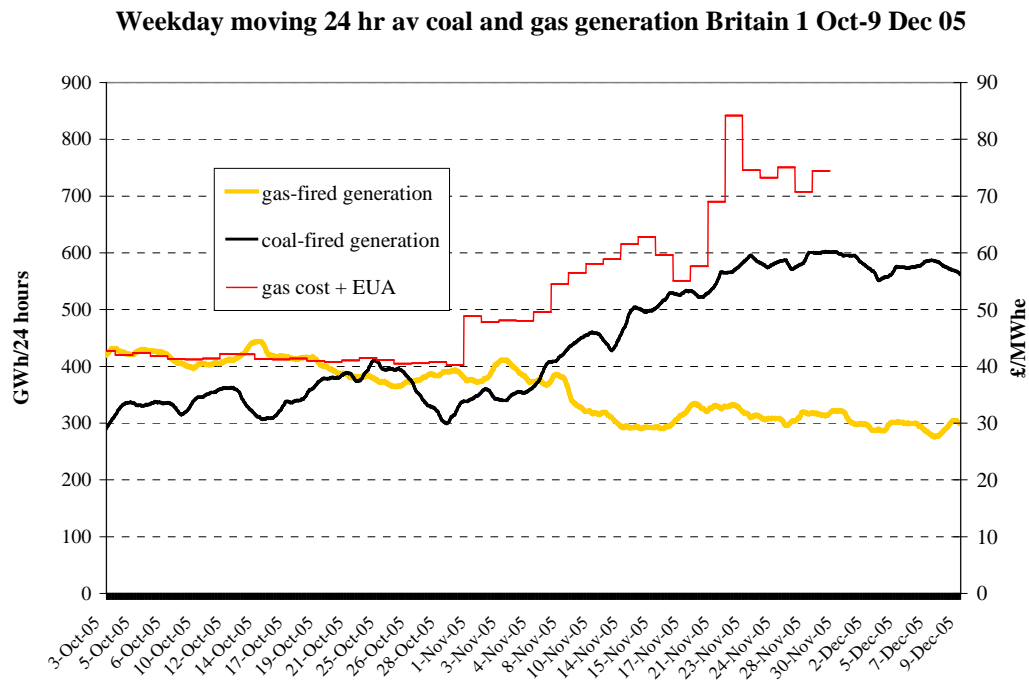
Figure 3 Impact of gas price increases on gas demand in the British ESI
Source: NGT, Platts, EEX carbon index

Spain and Italy (unfortunately not ideal models of competitive wholesale markets) give hourly data on the fuel of the marginal generator. Thus in Spain in 2005 gas-fired generation set the marginal price between 0 and 67% of the hours of each day, while thermal generation (mainly coal) sets the marginal price between 4% and 79% of the hours of each day. German market data reveal that output of coal and gas both vary over the course of each day, and in 2006 the output of gas-fired generation varied from 135 MW to 13,042 MW (with an average of 1,467 MW) while coal generation varied from 795 MW to 20,706 MW (with an average of 7,626 MW), indicating that the two fuels are competing to varying degrees over the course of the year. Figure 4 shows the monthly average of the hourly outputs in generation from the two fuels.

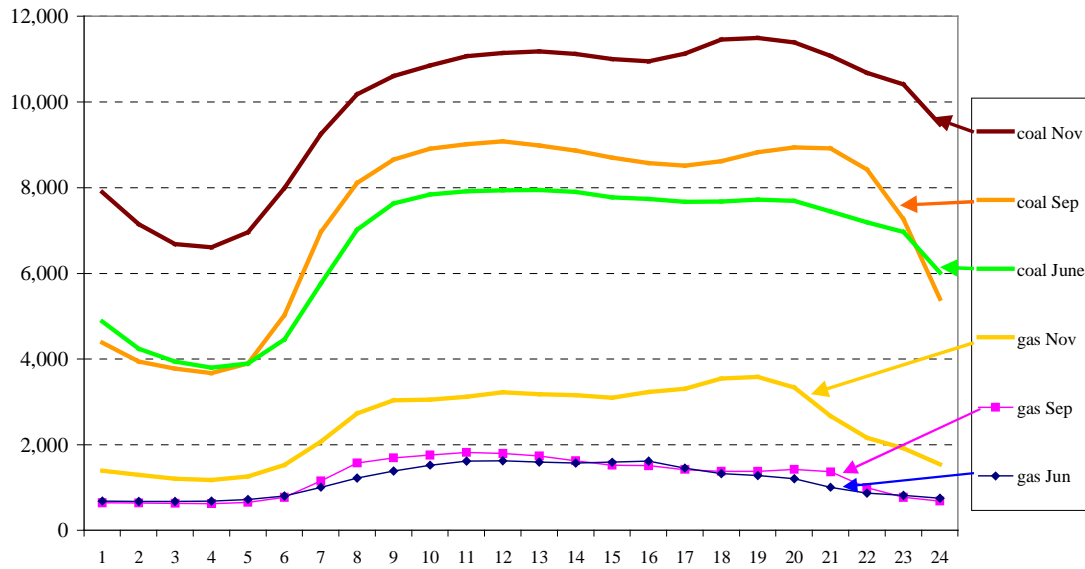Germany: Average hourly generation for gas and coal, 2006

Figure 4: Average monthly generation for gas and coal in Germany 2006
Source: EEX

2.2 Impact of the ETS on electricity prices

Theory argues that the price of EUAs should feed through to the wholesale price of electricity in a competitive market, although where final prices are regulated, the price could be held down to offset the windfall profits earned on the allocated EUAs. In most EU countries the wholesale electricity price is relatively unregulated (Italy and Spain may be exceptions).[3] Empirically, although EU electricity wholesale markets vary considerably in market concentration and competitiveness, there is considerable evidence that the price of EUAs does indeed feed through in large part to the price of electricity. The price of electricity rose dramatically in EU countries towards the end of the first year of emissions trading. Between December 2004 and March 2005 weekly average European base-load prices more than doubled from about 35 €/MWh to over 70 €/MWh, prompting a spate of complaints to the European Commission, who in response announced a sector inquiry into gas and electricity in June 2005 (European Commission, 2005).

Figure 5 shows 28-day centred moving averages of various prices and costs for the British market, where gas generation is particularly important, and where both the gas and electricity markets are competitive and for which there are liquid spot and forward markets. The electricity price is from the day-ahead power exchange, UKPX, for peak hours (7am-7pm), the gas cost is derived from the NBP gas spot price taking 0.36 EUAs/MWhe[4] of

---

[3] Ilex (2004) predicted the likely impact of EUA prices on wholesale prices and anticipated 100% pass-through in every country except Italy (0% pass-through) and Spain (8% pass-through).
[4] MWhe is Megawatt hours of *e*lectricity output, in contrast to the price of gas that expressed in £/MWh. At 50% efficiency it requires 2MWh of gas to generate 1 MWhe. Platts forward gas prices assume 55% efficiency, rather higher than average UK CCGT efficiency.

generation in a Combined Cycle Gas Turbine (CCGT) at 55% efficiency. The EUA cost is also shown separately. Year-ahead peak electricity prices in Britain rose from about 50 €/MWh in December 2004 to over 90 €/MWh by July 2005, while month-ahead gas prices rose from 15 €/MWh in December 2004 to 40 €/MWh in December 2005 (Platts). The *cost* of burning gas to generate electricity doubles this price if efficiency is 50%. Figure 5 demonstrates clearly that the main influence on the price of electricity was the price of gas, rather than that of the EUAs, although they move together, as Figure 1 and Figure 5 show.

**CCGT cost (55% efficiency) and peak prices in British electricity market**
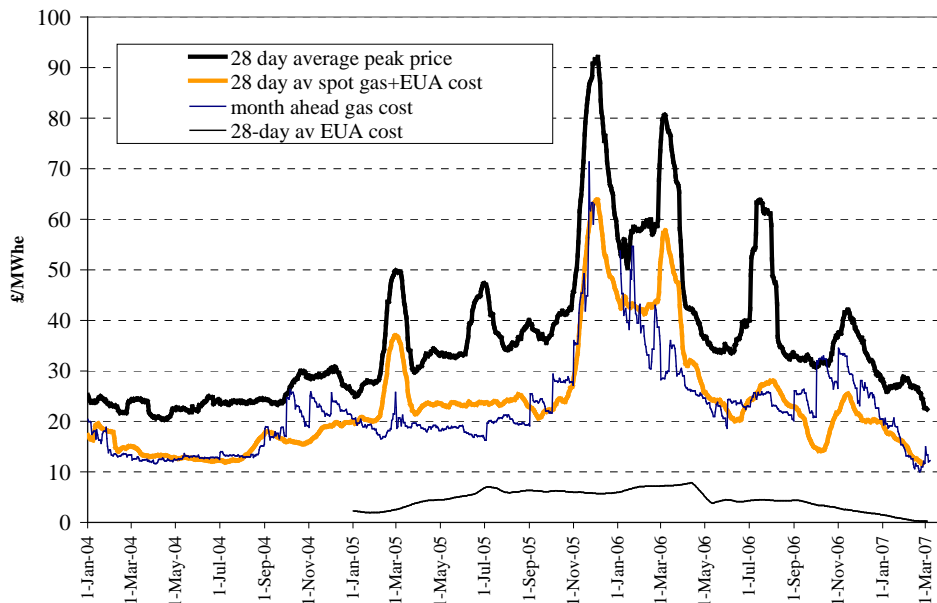
Figure 5 Spot electricity prices, gas and EUA costs in Britain
Sources: UKPX, Platts data, and EEX carbon index

A similar picture emerges from all the actively traded Continental power exchanges, and for both base-load and peak electricity, as Figure 6 shows. Again, most of the price rise could be attributed to a sharp increase in the price of gas, which increasingly sets the peak price in several EU countries.[5] Interestingly, French wholesale electricity prices moved in close sympathy with German and Dutch prices (which moved in harmony with Britain), even though French electricity is almost entirely nuclear and hence immune to the price of either gas or CO_2. Nevertheless, France trades directly with the Netherlands (and Britain), as does Germany, and although there are transmission constraints that often fragment the European electricity market, it is clear that prices in neighbouring countries move closely together. The price of gas affects electricity prices in countries that either use little or no gas in generation. However, the European Commission was sceptical that the price increase could be attributed to the normal functioning of competitive fuel markets and argued that the gas market in particular raised serious competition issues, discussed further below.

---

[5] Coal prices also rose sharply, doubling between January 2003 and December 2005 (IEA, 2007).

**Weekly average baseload spot prices 2004-Dec 2006**
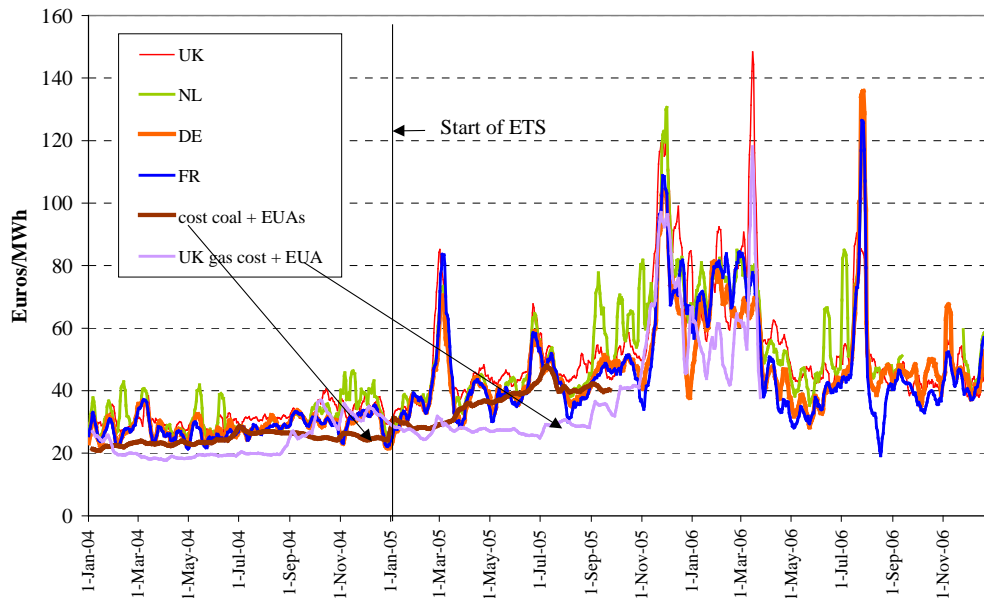
Figure 6 Electricity spot prices and fuel plus EUA costs on European power exchanges

Figure 5 and Figure 6 do not directly demonstrate that the price of EUAs feeds through directly to the price of electricity, although it strongly suggests that the wholesale spot price of electricity moves closely with the cost of gas, including the cost of EUAs. Figure 7 isolates the effect of the EUAs on the price of electricity by graphing the "clean spark spread" in various markets. The clean 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, *less* the cost of the EUAs needed, and is a measure of the gross profit needed to cover other variable costs such as O&M, and the fixed and capital costs of generation). The cost of the EUAs required varied over this period from about 3 to 12 €/MWh. The visual interpretation is that after an initial period of adjustment the clean spark spread has returned to where it had been, suggesting that most if not all of the EUA opportunity cost has been passed through into the wholesale price.[6]

A further indication that EUA prices feed rapidly into electricity prices is provided by evidence from the French and German forward markets around the time of the first dramatic collapse in EUA prices observed in Figure 1. Figure 8 plots the cost of the EUAs needed in 50% efficient gas turbines and 36% efficient coal-fired plant, and shows the response of the forward base-load prices in France and Germany to the sudden fall in the EUA price in late April 2006. The base-load French forward price for 2007 appears to have fallen almost as much as if it were determined by the cost of EUAs needed for coal-fired plant, rather than gas-fired plant (which requires fewer EUAs per MWh), even though French electricity is primarily nuclear needing no EUAs.

---

[6] Gas is the dominant fuel in the Netherlands (61% in 2004) but only accounts for 10% of generation in Germany where coal accounts for 51% (IEA, 2006).

Spark spread net of EUA
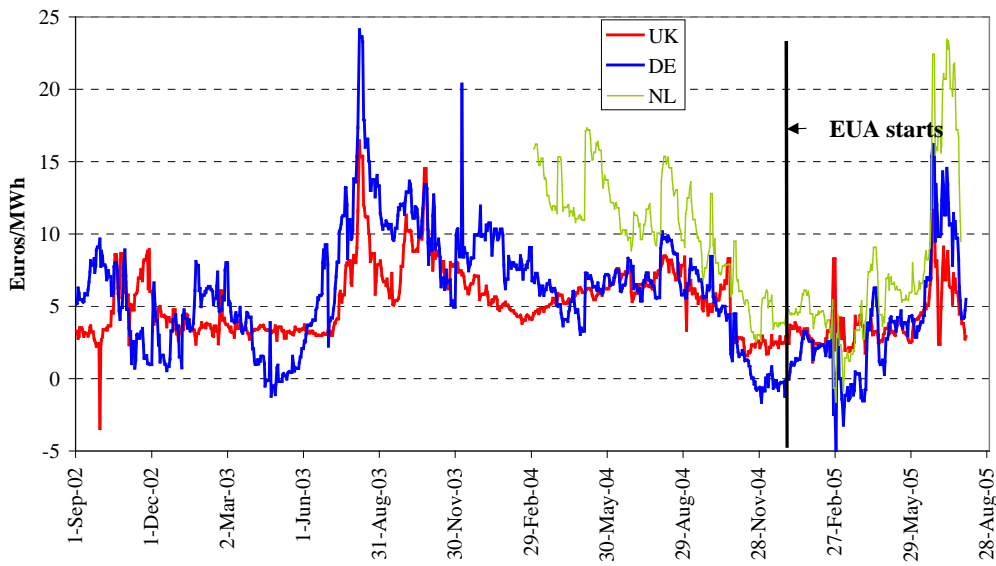
Figure 7 Clean spark spreads
Source: Platts

Forward base year contracts - France and Germany Aug 2005-May 2006
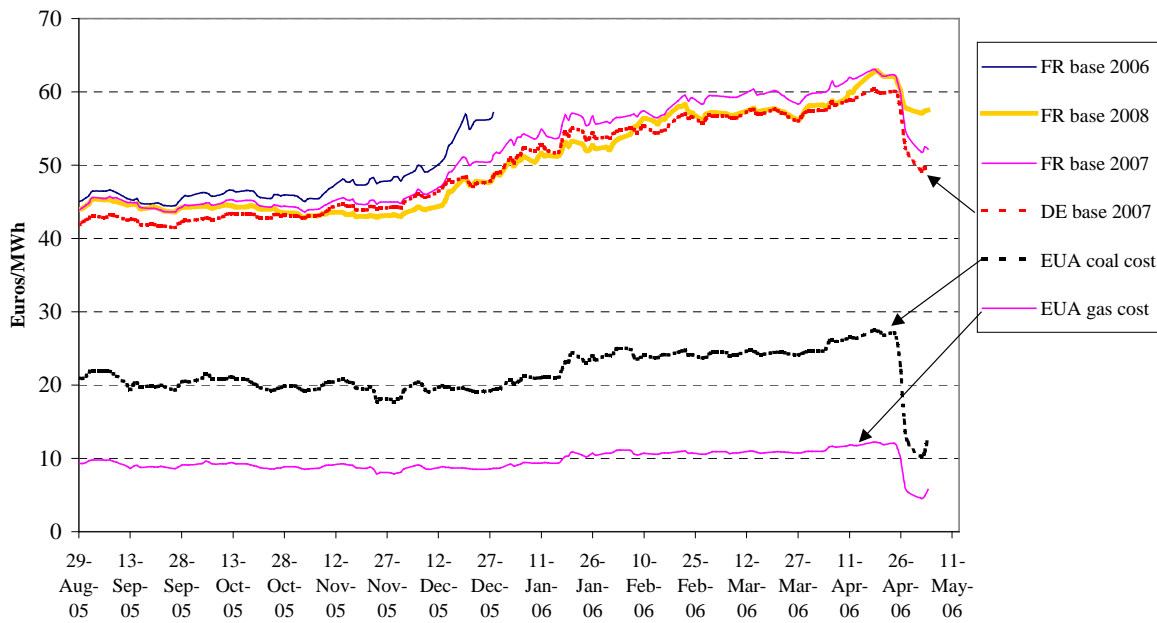
Figure 8 French and German forward prices and the cost of EUAs for generation
Source: EEX

Finally, various authors have undertaken econometric estimates of the extent to which EUA prices are passed through into electricity prices (IEA, 2007). Honkatukia et al (2006) estimated that 75-90% of EUA price changes were passed through to the Finnish Nord Pool

day-ahead prices, even though the Nordic market is dominated by nuclear and hydro electricity (but linked to the rest of Europe). In a sophisticated boot-strapping econometric exercise Sijm, Neuhoff and Chen (2006) examined the impact of EUA price changes on the cost of generating from coal in Germany, finding complete pass-through for peak prices and 60-70% for off-peak prices (when interconnectors are less constrained and imports introduce competition from other fuels) . In the Netherlands they found that 60-80% of the EUA price changes are passed through for peak hours for gas generation, and 70-80% passed through in off-peak hours for coal generation.[7]

2.3   *Market power in the gas market*

The price of EUAs is determined by supply and demand, and both depend on the extent to which the electricity supply industry (ESI) can substitute less carbon-intensive fuels like gas for more carbon-intensive fuels like coal though changes in the merit order.[8] As the price of gas increases, the price of EUAs increases, as the demand from coal-fired generation will increase demand for EUAs. That will reduce fuel switching from gas to coal, making the demand for gas less elastic, and thus enhancing the ability of those with market power in the gas market to increase prices. 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. The CEC *Sector Inquiry* concluded that gas wholesale markets "generally maintain the high level of concentration of the pre-liberalisation period. … incumbents remain dominant on their traditional markets, by largely controlling up-stream gas imports and/or gas production. … . The network of long term supply contracts between gas producers and incumbent importers makes it very difficult for new entrants to access gas on the upstream markets. … Gas infrastructure (networks and storage) is to a large extent owned by the incumbent gas importers, and the insufficient separation of this infrastructure from supply functions results in insufficient market opening." (EC, 2006, p3.)

There are therefore grounds for concern that the particular way climate change policy works in the EU through pricing a fixed supply of EUAs is likely to amplify the existing market power in the gas market. The next section shows how this can happen

3.   A simple model of pricing EUAs

To gain some insight into possible mechanisms, consider a very simple model in which the price of EUAs is dominated by supply and demand from the electricity supply industry, in the

---

[7] The impact of EUA price changes are roughly twice as high for coal as it is more carbon intensive. As Dutch electricity prices are above neighbouring countries, there may be less scope for passing cost increases through fully. Explaining spot electricity prices is particularly difficult as they are affected by contract cover, market power, the extent of the market, i.e. whether interconnectors are constrained, and the supply-demand balance, so the match between theory and evidence is impressive.
[8] The merit order is the order in which generation stations are called on to generate, starting with the cheapest for base-load, and successively choosing those with higher variable costs until the most expensive are reserved for peak demand.

following way. The price of coal is c (€/MWh of fuel), set on world markets,[9] and that of gas is g. The heat rate for fuel f ($f = c, g$) is h_f (MWh of fuel per MWh of *e*lectricity generated, or MWhe). The short-run marginal cost (SRMC) will be the variable fuel cost (per MWh) given by $h_f.f$ €/MWh.[10] The fuel prices are initially such that the variable generation cost using coal is less than gas: $ch_c < gh_g$. Emissions (tonnes CO_2 per MWh of energy content of fuel) f is e_f, so emissions per MWhe of electricity generated will be $h_f e_f$. If the price of EUAs is s €/t the SRMC, including the opportunity cost of the EUAs, will be $v_f = h_f.(f + se_f)$ €/MWhe. For the moment consider periods of the year in which there is enough gas and coal capacity to drive the relevant marginal cost down to the variable fuel cost, but there are not enough EUAs available to allow all demand to be met by coal capacity alone. If in such periods both technologies are required to meet demand (because of the constraint on the number of EUAs), then the price of EUAs, s, and the marginal revenue of electricity, R', must be such that both technologies are equally costly, and marginal revenue is equal to the same short-run marginal cost from each technology:

$$R' = h_c\,(c + e_c\,s) = h_g\,(g + e_g\,s),\tag{1}$$

or

$$s = \frac{h_g\,g - h_c\,c}{h_c e_c - h_g\,e_g}.\tag{2}$$

The relationship between the price of electricity, p, and the marginal revenue, R', in a Nash equilibrium in which firms take the supply decisions of others as given, is $R' = p(1-1/\varepsilon_{rd}) = \theta p$, where ε_{rd1} is the elasticity of residual electricity demand (i.e. demand less other firms' supply, as a positive number) and $\theta < 1$.[11] Hence, substituting for s:

$$R' = \theta p = \frac{h_g h_c \left(e_c\,g - e_g\,c\right)}{h_c e_c - h_g\,e_g}.\tag{3}$$

and that the impact of gas prices on electricity prices is amplified, for if the elasticity of residual demand is constant,[12]

---

[9] Coal is internationally traded from numerous countries, such as Australia, Colombia, the US, and South Africa. European coal mining costs are typically substantially above import prices and complex subsidy arrangements are in place to make them competitive with import prices, but at least for the past ten years the coal price delivered to EU power stations is set by import prices (Newbery, 1995).

[10] As defined, the heat rate is the inverse of the thermal efficiency, so for a CCGT of 50% efficiency the heat rate would be 2.

[11] If firms are not identical, then the residual demand elasticity may vary across firms, complicating the formulas but not altering the force of the argument.

[12] This is not an innocuous assumption for if the residual demand for electricity is linear, then less than 100% of the increase in cost is passed on under Cournot competition, although it is still true that the ETS magnifies the effect of an increase in the gas price.

$$\frac{dp}{dg} = \frac{h_g h_c e_c}{\theta(\ h_c e_c - h_g e_g\ )} = \frac{h_g}{\theta}\left(\frac{1}{1 - h_g e_g / h_c e_c}\right) > \frac{h_g}{\theta}. \qquad (4)$$

Note that the partial effect of gas prices on electricity prices holding the price of EUAs constant is just h_g/θ so the effect of the feedback through the market for EUAs is given by the bracketed term, which magnifies the effect. This demonstrates the first claim of the paper, that the ETS *amplifies* the impact of a rise in gas prices on the price of electricity.

To put some numbers on this suppose that h_g is 2, h_c is 2.65, $e_c = 0.34$ tonnes CO_2/MWh and $e_g = 0.2$ tCO_2/MWh, then the multiplication factor will be 1.8 compared with a market in which the price of gas does not affect the price of EUAs. Interestingly, if coal becomes more efficient relative to gas the multiplier increases. Thus if h_c were to fall to 2.5 the multiplier would become 1.9.

This has interesting implications for the profits of generation companies, even if the companies are competitive.[13] Suppose that their baseline output is Q and they are allocated $h_a e_a Q$ EUAs, where $h_a e_a$ is an average emission factor per MWhe corrected by the amount of coverage (e.g. 95%). The profit of the company if it sells q units of electricity is

$$\begin{aligned}
\Pi &= pq + s e_a Q - (r + s e_g)\alpha q - (c + s e_c)(1 - \alpha)q \\
&= s e_a Q + (1-\theta)pq,
\end{aligned} \qquad (5)$$

during those periods when the arbitrage equation (1) holds (and assuming no inframarginal coal or gas plants) (where α is the share of generation from gas during this period). Again from the price equation (2) for EUAs and the price equation (4), if the elasticity of residual demand is constant so that θ is independent of p:

$$\begin{aligned}
\frac{d\Pi}{dg} &= \left(\frac{h_g e_a h_a}{h_c e_c - h_g e_g}\right)Q + (1-\theta)R'\frac{dq}{dp}\frac{dp}{dg}, \\
&= \left(\frac{h_g}{h_c e_c - h_g e_g}\right)\left(e_a h_a \frac{Q}{q} - \left(\frac{1-\theta}{\theta}\right)h_c e_c\right)q,
\end{aligned} \qquad (6)$$

and as the second term is small for plausible values of θ compared to the first term,[14] profits will rise with the price of gas. The reason for this apparently counterintuitive result is that electricity companies can recover the full cost of any fuel *and carbon* required to generate in the electricity price, and *in addition* they are granted the initial grandfathered allocation of EUAs. Gas price increases directly increase the value of these EUAs (and electricity companies in the EU have been enjoying record profits since the start of the ETS). This might give generating companies with large gas interests and market power in the gas market (e.g. E.On-Ruhrgas in Germany) an extra incentive to raise the price of gas. Again, to put some numbers on this, suppose that the

---

[13] If companies are not competitive, then (5) has an extra term $R(q) - qR'(q)$, whose derivative is $-q R''.dq/dp.dp/dg$.

[14] The second term will be zero for competitive electricity generators.

baseline allocation is 95% and that the initial share of coal is 80%, then $h_a e_a = 0.8$ tCO$_2$/MWhe and if $\theta = 90\%$, (so the Lerner mark-up would be 10%), the overall multiplier of q in (6) is 2.64. If the Lerner mark-up rises to 20% the multiplier falls to 2.14, and for a perfectly competitive electricity firm the multiplier would be 3.04.

Another way to examine the incentives to raise gas prices is to examine the demand for gas by the ESI as a function of the EUA price, s. To simplify further to a competitive electricity market, in those hours when demand is high enough to require both coal and gas generation, but there is overall excess capacity and hence variable cost pricing, coal and gas plants are perfect substitutes. The price of EUAs is set by the coal and gas prices according to (2). Equilibrium in the market for EUAs will thus depend on the supply of EUAs to the ESI, as in Figure 9.
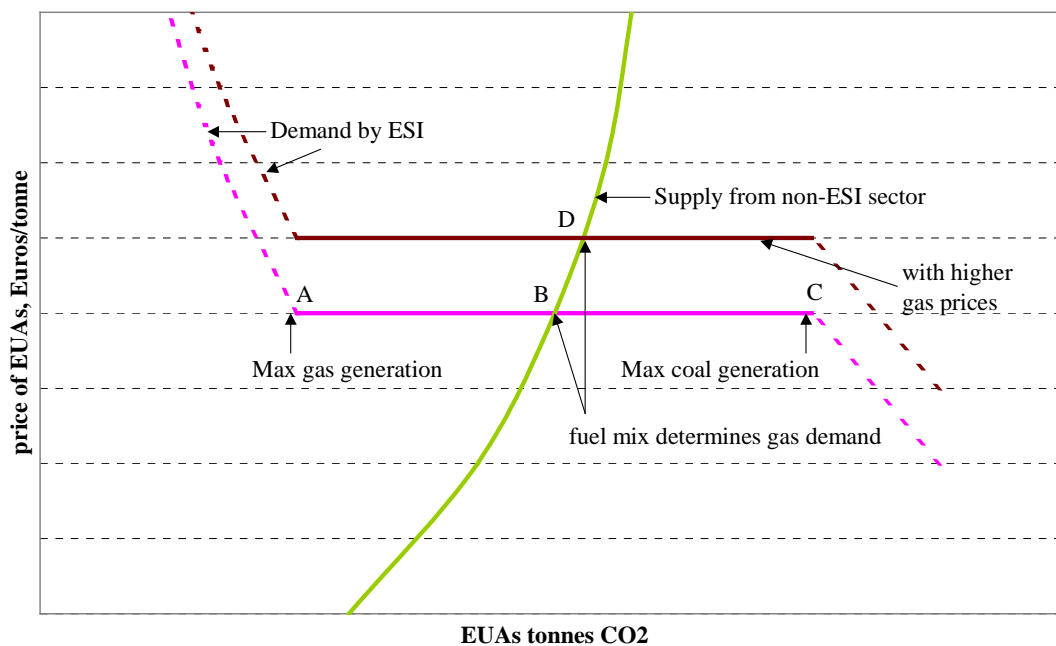
Figure 9 Supply and demand of EUAs in the electricity supply industry

The flat section of the demand for EUAs by the electricity supply industry (ESI), ABC, shows the range of combinations of coal and gas-fired plant that is capable of meeting demand during these hours, with low emissions requiring all CCGTs to run, at A, and point C corresponding to the minimum gas use and maximum coal use. The actual demand for gas will be set by the intersection of the supply of EUAs from the rest of the economy at point B. From (2), $ds/dg > 0$, so if the price of gas increases, the whole ESI demand schedule for EUAs moves up, as in Figure 9, and the equilibrium shifts from B to D, which reduces the demand for gas as coal substitutes for gas (point D is closer to the maximum coal end of the horizontal part of the schedule).

The next step is to see how these effects feed through into the demand for gas and hence on the market power of gas suppliers.

4.   The impact of the ETS on the elasticity of gas demand.

The simple model of the electricity sector has a number of obvious drawbacks, in that it only considers the case of perfectly elastic substitutability of gas for coal. While it gives a very direct link between the price of electricity and the prices of the fuels and EUAs, it does not provide a very helpful view of the demand for gas, and it only applies to part of the year. As the carbon price is determined by multi-annual demand and supply it is important to extend the model to cover with varying levels of demand, and in so doing it is possible to develop a more realistic model of the demand for gas, which is our central concern.

In the Appendix we construct an explicit algebraic model of the ESI, in which coal and gas compete for their position in the merit order. As the price of gas rises, so coal displaces gas and increases the demand for EUAs and hence the equilibrium price of carbon, which feeds back into the price of electricity (as noted above) and also the demand for gas. To show that this is a non-negligible effect, first note that the ESI accounts for more than half the allocation of allowances in the ETS, and next, that the demand for gas in the ESI is indeed sensitive to the prices of gas and EUAs (see Figure 2).

As the argument is completely general, we suppose that the demand for gas, $G,$ is a function of both the price of gas, g, and the price of EUAs, s, as the price of coal is set on internatinal markets and is not affected by local fuel demands:

$$G = G(g,s),$$

so, differentiating totally with respect to g:

$$\frac{g}{G}\frac{dG}{dg} = \frac{g}{G}\frac{\partial G}{\partial g} + \frac{s}{G}\frac{\partial G}{\partial s}\frac{g}{s}\frac{ds}{dg}. \tag{7}$$

The supply of EUAs to the electricity industry, $S(s)$, depends on the price of EUAs, and in equilibrium is equal to the demand for EUAs by the ESI, $E(g,s)$:

$$S(s) = E(g,s).$$

The impact of a change in the price of EUAs is found by differentiating this totally w.r.t. g:

$$\frac{dS}{ds}\frac{ds}{dg} = E_g + \frac{\partial E}{\partial s}\frac{ds}{dg},$$

so

$$\frac{g}{s}\frac{ds}{dg} = \frac{gE_g/E}{\eta-\xi}, \quad \eta \equiv \frac{d\log S}{d\log s}, \quad \xi \equiv \frac{\partial \log E}{\partial \log s},$$

where η is the elasticity of supply of EUAs to the ESI and ξ is the elasticity of demand for EUAs by the ESI, a negative number, and we have taken advantage of the equality $S = E$.

The own-price elasticity of demand for gas, $\varepsilon^* = d\log G/d\log g$, allowing for indirect effects on the price of EUAs, is given from (7)

$$\varepsilon^* = \varepsilon + \frac{s}{G}\frac{\partial G}{\partial s}\frac{gE_g/E}{\eta-\xi},$$

where $\varepsilon = \partial\log G/\partial\log g$ is the price elasticity of demand for gas if there is no change in the price of EUAs. The demand for gas increases with the price of EUAs, as it displaces more

carbon-intensive fuels, so $G_s > 0$, and as $E_g > 0$, the last term is positive. Both the price elasticities of gas are negative, so the effect of forcing the price of EUAs to change in response to a change in the price of gas is to make the own-price elasticity of gas demand smaller in absolute value, i.e. less elastic.

The appendix shows in more detail how to estimate the importance of this effect for a more realistic model of the electricity industry, where it is shown that the ratio of the price elasticity of demand for gas with and without the ETS is given as

$$\frac{\varepsilon^*}{\varepsilon} = \left(\frac{\eta}{\eta + \phi} \right), \tag{8}$$

where ϕ is derived from the characteristics of gas and coal-fired generation (and for the UK may lie between 0.3 and 0.6). For example, if $\eta = 0.3$, then this ratio is between one-third and one-half.

The ESI and other energy industries account for about 40% of total UK gas consumption, less than domestic consumption and services, which are not part of the ETS. If we assume that the ETS only affects half of gas demand, and if the pre-ETS elasticities of the covered and uncovered sectors are the same, then the overall price elasticity of demand will fall to between two-thirds and three-quarters of its previous level. That in turn means that the Lerner Index (the mark-up as a fraction of the price) will be increased by between 33% and 50%.[15] That is a very appreciable increase in potential market power.

Although these numerical calculations are based on a calibrated model of the British ESI, the argument is completely general. It is well known that demand is less elastic in the presence of rationing, even where the rationing applies to other markets than the one under study (Deaton and Muellbauer, 1980, 4.3; Neary and Roberts, 1980). This in turn is an illustration of the Le Chatelier Principle that constraints reduce the elasticity of response, as noted by Samuelson (1947) and set out in standard textbooks (e.g. Varian, 1984, p56). The same applies if the quantity of EUAs is fixed, as this reduces the elasticity of demand for gas and enhances the market power of those selling gas.

5.   Policy implications

The amplification of market power works through the impact on the price of EUAs, which, as gas prices rise and lead to coal substituting for gas, raise emissions and hence the price of EUAs, which in turn favours gas, offsetting the normal market demand response to an increase in the price of gas. As the EU gas market is thought to be less competitive than either the electricity or coal market, and as Gazprom clearly has some market power,[16] it seems desirable to find ways of addressing climate change without exacerbating these other

---

[15] If, as seems likely, the elasticity of gas demand in the covered sector is higher than in the uncovered sector, then the effect will be larger. Thus if the covered elasticity is twice the uncovered value, the overall elasticity will fall to between 5/9 and two-thirds of its previous value, and the Lerner index will rise by between 50 and 80%.

[16] Gazprom sells on long-term contracts at prices linked to the price of oil, which alleviates its ability to manipulate prices, but contracts with new customers can be struck at different initial prices that reflect this market power, while Gazprom is also integrating into downstream supply.

market failures, particularly where the result is not just a redistribution of income between gas companies and consumers within the EU (as well as extra dead-weight losses) but also an increased transfer to gas producers outside the EU. Even if the gas market were competitive, the ETS amplifies the impact of any rise in the price of gas on the price of electricity, which is surely an unintended side effect of a the EU policy towards CO_2 emissions. Both effects work whether or not the electricity market is competitive. Indeed, if the elasticity of the residual electricity demand is constant, the impact of a gas price rise is even greater in the presence of electricity market power.

The obvious solution to these perverse effects is to cut the link between the demand for EUAs and their price by fixing the price of the EUAs. This could be done either by the European Commission (or some body) being prepared to buy and sell any number of EUAs at the fixed price, or by replacing the ETS by a fixed carbon tax per tonne of carbon burned. The former is likely to be politically more attractive than the latter, and can be made cash positive or neutral to the EC by suitable reductions in the allocations of EUAs each year. Jacoby and Ellerman (2004) discuss a similar proposal termed the "safety valve".

Banking of allowances over long periods of time should also increase the elasticity of supply of EUAs to the ESI, although it will not eliminate the volatility of carbon prices. For example, if the elasticity of supply of EUAs to the ESI, η, increases to $\eta = 1$, the elasticity of ESI gas demand rises to 63% of its former level, the total gas demand elasticity rises to 82% of its former level and the Lerner mark-up only rises by 22%. If $\eta = 2$, then the mark-up only rises by 13%.

There are additional arguments for setting the price of carbon and allowing the market to determine emissions, rather than setting the quantity and allowing the market to determine the price, all deriving from the insights of Weitzman's seminal paper on prices vs. quantities. Weitzman (1974) started a lengthy debate by observing that in the presence of uncertainty, permits are only superior to taxes if the marginal benefit of abatement schedule is steeper than the marginal cost of abatement schedule. This might be the case if marginal damage were low until some threshold level, at which point it suddenly increases. For most pollutants the marginal abatement cost schedule is fairly flat and low for modest abatement, but rises rapidly as a higher fraction of emissions is to be curtailed. The damage contributed by emissions today is effectively the same as those tomorrow, and so the marginal benefit of abatement is essentially flat at each moment, while the marginal cost of abatement rises rapidly beyond a certain point, arguing for taxes rather than quotas.

6.   Conclusions

Policy towards CO_2 emissions (or greenhouse gases, GHGs, more generally), should aim to reduce their damage without exacerbating other market failures. The ETS restricts total emissions of CO_2 and determines their price in each of the two periods by market trading. As a result the price, which is supposed to reflect the marginal social damage of emissions, is affected by the price of gas, which has nothing obviously to do with the marginal social damage. Furthermore, the price of electricity is made more sensitive to the price of gas, again to no social benefit. In addition, the quantity nature of the ETS amplifies market power in the

gas market, which the European Commission has determined is uncompetitive. Obviously it is desirable to eliminate market power in the gas market, but even if that is done (and it seems most unlikely that the Commission has sufficient power to do that), the other problems remain. Finally, the fixed quantity of ETS makes the EUA price volatile (although trading between years reduces this volatility somewhat). This volatility is costly in a variety of ways, not least in making investment decisions more risky and therefore the cost of capital higher.

There are powerful arguments for preferring a climate change policy that stabilises the price of EUAs, based on the stock nature of GHG emissions, and given uncertainties and ignorance about the nature of the costs of mitigation and of climate change.[17] This paper has advanced an additional argument in favour of stabilising the price of EUAs rather than the quantity, in that CO_2 quotas rather than taxes amplify the damaging effects of imperfect competition in the gas market.

It is well known that tariffs and quotas are not equivalent in the presence of imperfect competition in domestic markets (Bhagwati, 1965), and that under certainty, tariffs are superior (in the strong sense that an optimal tariff would be better than the optimal quota). The reason is simple – a binding quota limits imports of competing products and makes the residual demand facing the home supplier less elastic than would be the case if imports were subject to a tariff. It is also well known that demand is less elastic in the presence of rationing, even where the rationing applies to other markets than the one under study, as noted above. The lower the demand elasticity facing those with market power, the higher will the price be raised above the competitive level. Banking over longer time periods is an obvious way of both stabilising the carbon price (to some extent) and reducing the impact of the ETS on market power in the gas market.

The political advantages of the current ETS should not be underestimated, and these need to be retained when designing the next phase to start in 2008. The preferred solution would be to agree a price for GHGs, and for the European Commission to be willing to sell any demanded and not supplied by the market, or to intervene to buy back surplus EUAs. The allowances to be allocated free should be scaled back so that the risk of the EC having to buy back EUAs is reduced to very low levels.

Although the flow damage schedule is essentially flat, it has been argued (most recently by Stern, 2006) that the stock damage schedule (i.e. the damage set in train at different levels of CO_2 concentration) could be sharply increasing beyond some point, which is an argument for steering the carbon price to meet a cumulative stock target. As better information about EU GHG supply and demand, and about the costs and benefits of reducing GHG emissions, arrives, so the intervention price can be modified, although there are probably good arguments for issuing long-term contracts for differences on the prevailing price to provide greater certainty for low-carbon investments. There are possibly stronger arguments for governments issuing put options on carbon to create credibility (Ismer and Neuhoff, 2006).

---

[17] Hoel and Karp (2001) examines the impact of uncertainty about climate change damages, while Karp and Zhang (2004) also consider uncertainty and asymmetric information about the costs of abatement and learning about the cost of global warming.

References

Bhagwati, Jagdish (1965). "On the Equivalence of Tariffs and Quotas" in *Trade, Growth, and Balance of Payments: Essays in Honor of Gottfried Haberler*. editors: R.E. Baldwin et.al. Chicago.

European Commission (2005). *The Week in Europe* 17 June 2005 available at http://www.cec.org.uk/press/we/we05/pdf/we0523.pdf

European Commission (2006). *Sector Inquiry under Art 17 Regulation 1/2003 on the gas and electricity markets*, *Preliminary Report Executive Summary*.16 Feb, Brussels, CEC

Deaton, Angus, and John Muellbauer (1980). *Economics and consumer behavior*, Cambridge: CUP.

DTI (2007) *Quarterly Energy Prices,* March, available at http://www.dti.gov.uk/energy/statistics/index.html

Ellerman, A.Denny, and John Parsons (2006) "European Unit Allowances: a theory of pricing", presentation at the CMI-Iberdrola Electricity Conference, Madrid, 1 June, available at http://web.mit.edu/ceepr/www/Madrid/

Hoel, Michael, and Larry Karp (2001). "Taxes and quotas for a stock pollutant with multiplicative uncertainty." *Journal of Public Economics*, 83, 91-114

Green, Richard .J., and David M. Newbery (1992). "Competition in the British Electricity Spot Market." *Journal of Political Economy* 100 (5), October, pp 929-53.

Honkatukia, J., Mälkönen, V., Perrels, A., (2006). "Impacts of the European Emissions Trade System on Finnish Wholesale Electricity Prices." VATT-Discussion Papers, Helsinki.

IEA (2006). *World Energy Outlook, 2006*, Paris: International Energy Agency

IEA (2007). *CO_2 Allowance and Electricity Price Interaction Impact on Industry"s Electricity Purchasing Strategies In Europe*, Paris: International Energy Agency

Ilex (2004). "Impact of the EU ETS on European Electricity Prices." A report to DTI, Oxford, UK.

Ismer, Roland, and Karsten Neuhoff (2006). "Commitments through Financial Options**:** A Way to Facilitate Compliance with Climate Change Obligations.**"** Cambridge EPRG working paper available at http://www.electricitypolicy.org.uk/pubs/wp.html

Jacoby, Henry D., and A. Denny Ellerman, (2004). "The safety valve and climate policy." *Energy Policy*, 32 (4), 481-491

Karp, Larry, and Jiangfeng Zhang (2004). "Regulation with anticipated learning about environmental damages", University of California, Berkeley

Klemperer, Paul. D. and Margaret A. Meyer (1989). "Supply Function Equilibria in Oligopoly under Uncertainty." *Econometrica*, 57 (6), pp. 1243-1277.

Neary, J.Peter, and Kevin W..S. Roberts (1980). "The Theory of Household Behaviour under Rationing." *European Economic Review*. 13(1): 25-42

Newbery, David M. (1995). "Removing coal subsidies: Implications for European electricity markets", *Energy Policy*, **23**(6), 523-33.

Newbery, David M. (2005). "Climate change policy and its effect on market power in the gas market." Update available as EPRG Working Paper at http://www.econ.cam.ac.uk/cgi-bin/eprg2.pl

Platts reporting services, http://www.platts.com

Samuelson, Paul.A. (1947). *Foundations of Economic Analysis,* Cambridge Mass: Harvard

Sijm, Jos, Karsten Neuhoff and Yihsu Chen (2006). "CO2 cost pass through and windfall profits in the power sector", Cambridge University EPRG 0617 Working Paper

Stern, Nicholas H. (2006). *The economics of climate change¸* Cambridge: CUP

US EPA (2003). *NOx Budget Program: 1999-2002 Progress Report*. U.S. Environmental Protection Agency and the Ozone Transport Commission, available at http://www.epa.gov/airmarkets/otc.

Varian, Hal R. (1984). *Microeconomic Analysis* New York: Norton

Weitzman, Martin L. (1974). "Prices vs. Quantities", *Rev. Econ. Stud.* **41** (4), 477-91

Appendix Deriving the demand for gas by the ESI

To keep matters as simple as possible, assume that the price of carbon has little effect on the demand for electricity (compared to the demand for carbon), and that there are two technologies, gas and coal.[18] Assume that all gas-fired plant is equally efficient but limited in capacity, measured by K_g MW, so the variable cost of gas-fired plant is constant. Coal plants, in contrast, vary in efficiency, and the heat rate of the marginal plant increases with supply. Put another way, older less efficient coal plant is placed lower down the merit order and is only called after more efficient plant. The unsubscripted heat rate now refers to coal and is a function of its position in the merit order, with $h(K)$ the heat rate of the marginal coal plant of the most efficient K MW of coal plant, $K < K_c$, the total coal capacity.[19] The simplest such model would have $h(K) = h_0 + \alpha K$, (where α has dimensions MW^{-1}) giving a linear increasing marginal cost schedule.

The merit order will now depend on the prices of coal, gas and EUAs. The variable (or marginal) cost of CCGT will be, as before, $v_g = h_g(g + se_g)$. The marginal cost of coal-fired plant is a function of K: $v(K) = h(K)(c + se_c)$, which will be linear if the heat rate is linear: $v(K) = (h_0 + \alpha K)(c + se_c)$. The interesting case has some coal plant cheaper than gas, but older plant more expensive, or $h_0(c + se_c) < h_g(g + se_g) < (h_0 + \alpha K^*)(c + se_c)$, where if D^* is peak demand, $K^* = D^* - K_g$. (Other cases are discussed in Newbery, 2005) Suppose the load duration curve is given by $D(t) = b + \mu(1-t)$, where t is the fraction of the year that demand is higher than $D(t)$ MW and both b and μ are measured in MW, as shown in figure A1. Given the capacity of CCGT, $D^* = D(0) = b + \mu = K^* + K_g$ (so $K^* = b + \mu - K_g$).

The merit order determines how many hours each plant runs and therefore generates and emits. Suppose that the lowest load factor CCGT runs a fraction $1-T$ of the year, then one possible configuration of the merit order has K_1 units of coal plant running on base-load, followed by $b - K_1$ units of CCGT running base-load and the remaining μT MW of CCGTs running mid-merit, with the $\mu(1-T)$ units of higher cost coal supplying the peak, as in figure A1. The value of K_1 is such that the marginal costs of coal and gas are there equal, so

$$(h_0 + \alpha K_1)(c + se_c) = h_g(g + se_g) ,$$

or

$$K_1 = \frac{h_g(g + se_g)}{\alpha(c + se_c)} - \frac{h_0}{\alpha} . \tag{A1}$$

---

[18] This is not restrictive, given that the emissions per unit of electricity produced is increasing for "coal" units, so oil-fired plants can also be considered with a suitable reinterpretation of the heat rates.
[19] The model is simplest to understand if the electricity market is competitive, for then the merit order depends solely on marginal costs and not on the distribution of plant ownership. The model would also work if all firms were identical in their shares of coal and gas plant under imperfect competition. The combination of imperfect competition and asymmetries would complicate the analysis of equilibrium, but not fundamentally alter the results.
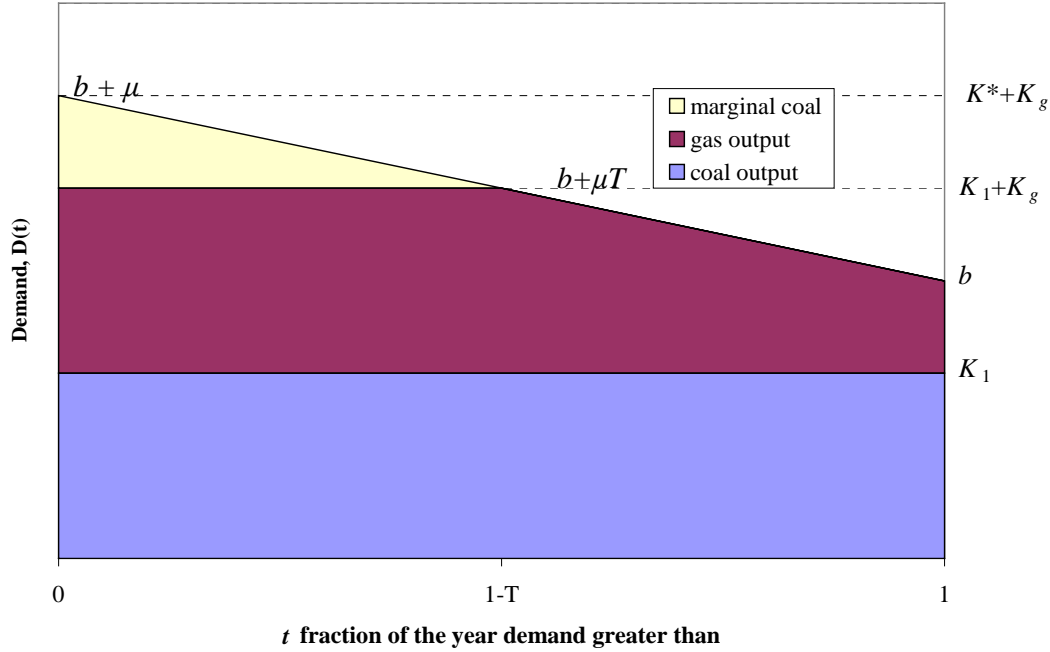
Figure A1 Load duration curve and generation from each fuel

The value of T then solves $b + \mu T = K_1 + K_g$, or $T = (K_1 + K_g - b)/\mu$. The total generation of gas-fired electricity is found by geometry from figure 1 to be the base-load and mid-merit outputs: $Q_g = b - K_1 + \frac{1}{2}\mu T(2-T)$ MW years. Emissions from gas-fired plant are $E_g = 8760 \, h_g e_g Q_g$. Total coal-fired generation is $Q_c = K_1 + \frac{1}{2}\mu(1-T)^2$ MW years, but emissions will vary with the plant dispatched, and must be found by integration:

$$E_c = 8760 \, e_c \left(\int_0^{K_1} h(q)dq + \frac{1}{\mu} \int_{K_1}^{K*} (K*-q)h(q)dq \right) = E_c(K_1). \qquad (A2)$$

As the price of EUAs increases, so the volume of base-load coal plant, K_1, decreases as gas is favoured in the merit order, increasing its share of total generation and thus displacing more carbon-intensive coal. Total emissions, $E = E_g + E_c$, are therefore a decreasing function of the EUA price, s. If the supply schedule of EUAs from other sectors supplied to the market is increasing in s, the equilibrium value of s will be determined by the intersection of supply and demand.[20] If the price of coal is assumed constant, then the price of EUAs will depend on the price of gas.

Exercising market power in the gas market

The demand for gas from the ESI will depend on its price, the price of coal (which is assumed constant and independent of demand), and the price of EUAs, which is in turn determined by the prices of fuels. The main question to be addressed is whether the particular form of the ETS amplifies, mitigates, or is neutral to the exercise of market power by gas

---

[20] The qualification is that EUAs can be used any time between 1 Jan 2005 and 31 Dec 2007 so the demand and supply should be thought of as 3-year totals selling in theory at a single price, as illustrated in figure 1.

suppliers. To simplify, suppose the supply of EUAs to the ESI, $S(s)$, depends on the price of EUAs only and not on the price of gas. (This assumption can be relaxed without changing the direction of the results, but at the cost of greater complexity in modelling the EUA market.)

The ESI demand for gas is $G = 8760h_gQ_g = \theta Q_g$, which is a function of K_1, so $dG/dg=\theta(dQ_g/dK_1).(dK_1/dg)$. For the merit order shown in Figure A1, $dQ_g/dK_1 = -T$. The crucial derivative is therefore dK_1/dg, which from (A1) is

$$\frac{dK_1}{dg} = \frac{\partial K_1}{\partial g} + \frac{\partial K_1}{\partial s}\frac{ds}{dg} \ . \tag{A3}$$

The value of ds/dg can be found by examining the intersection of the demand for and supply of EUAs to the ESI. The demand for EUAs by the ESI is a function of the price of gas and of EUAs, $E\{K_1(g,s)\}$, whereas the supply is just a function of the EUA price, $S(s)$. Equilibrium in the market for EUAs is found from $S(s) = E\{K_1(g,s)\}$. Differentiate this totally with respect to the gas price, g:

$$\frac{dS}{ds}\frac{ds}{dg} = \frac{\partial E}{\partial K_1}\left(\frac{\partial K_1}{\partial g} + \frac{\partial K_1}{\partial s}\frac{ds}{dg}\right),$$

or, rearranging and simplifying

$$\frac{ds}{dg} = \frac{\dfrac{\partial K_1}{\partial g}\Big/\dfrac{\partial K_1}{\partial s}}{\dfrac{dS}{ds}\Big/\left(\dfrac{\partial E}{\partial K_1}\dfrac{\partial K_1}{\partial s}\right)-1} \ .$$

This can now be inserted into equation (A3) to give

$$\frac{dK_1}{dg} = \frac{\partial K_1}{\partial g}\left(1-\frac{1}{1-\dfrac{\partial S}{\partial s}\Big/\left(\dfrac{\partial E}{\partial K_1}\dfrac{\partial K_1}{\partial s}\right)}\right). \tag{A4}$$

The various terms can now be derived from (A2) as follows:

$$\frac{\partial E_c}{\partial K_1} = 8760\,e_c\left(h(K_1)-\frac{1}{\mu}(K*-K_1)h(K_1)\right)=8760\,e_c\,h(K_1)T,$$

which makes use of the relation $K*-K_1 = \mu(1-T)$. Given the equation for $E_g = 8760\ h_ge_gQ_g$, the full derivative is:

$$\frac{\partial E}{\partial K_1} = 8760T\big(e_c\,h(K_1)-e_g\,h_g\big)>0. \tag{A5}$$

The term $\partial K_1/\partial s$ is found from (A1) to be

$$\frac{\partial K_1}{\partial s} = -\frac{h_g(e_c g - e_g c)}{\alpha(c + se_c)^2} < 0. \tag{A6}$$

If the elasticity of supply of EUAs to the ESI is η, then $\partial S/\partial s = \eta E/s$, and all the necessary elements are now available to calculate the elasticity of ESI demand for gas with the ETS:

$$\varepsilon^* = \frac{g}{G}\frac{dG}{dg} = \frac{-\theta T}{\theta Q_g}\frac{g}{dg}\frac{dK_1}{dg} . \tag{A7}$$

The elasticity without the ETS (or with the price of EUAs independent of the price of gas), ε, is found by replacing dG/dg by $\partial G/\partial g$. The ratio of the elasticity with and without the ETS is then given from (A4) as

$$\frac{\varepsilon^*}{\varepsilon} = \left(\frac{\eta}{\eta + \phi}\right), \quad \phi \equiv \left(\frac{K_1 \partial E}{E \partial K_1}\right)\left(\frac{-s\partial K_1}{K_1 \partial s}\right). \tag{A8}$$

Table 1 gives rough values for the parameters to calibrate the model for Britain (shading indicates variations).

Table 1 Parameters for calibrating the model to Britain, 2005

gas heat rate	h_g		2	2
coal base heat rate	h_0		2.5	2.63
rate of change of HR	α	per GW	0.025	0.03
CO2 per MW gas	e_g	tonnes/MWh	0.2	0.2
CO2 per MW coal	e_c	tonnes/MWh	0.34	0.34
min demand	b	GW	25	25
Slope of load duration	μ	GW	30	30
gas capacity	K_g	GW	20	20
coal capacity	K_c	GW	40	40
Price of gas	g	€/MWh	16	16
Price of coal	c	€/MWh	6	6
EUA price	s	€/tonne CO_2	20	20

Given these values, $\phi = 0.59$ and 0.29 respectively. If the elasticity of EUA supply, η, is 0.3, then the elasticity of gas demand by the ESI is reduced to one-third and one-half its unconstrained value respectively.

The effect of an increase in gas price on the demand for (and hence price of) EUAs is unambiguous. Higher gas prices move gas down the merit order (and up the load duration schedule in figure A1) and reduce gas-fired generation, increasing emissions and hence increasing the demand for EUAs, raising their price and magnifying the impact of the gas

price rise on the price of electricity. Equation (A8) shows that the effect of carbon trading is to *reduce* the elasticity of demand for gas, *amplifiying* the market power of the gas supplier.

Extensions

The model gave a direct link between the electricity price and the price of gas and EUAs, as it only studied periods of excess capacity and variable cost (i.e. competitive) pricing. A more realistic model would allow for imperfect competition, and higher mark-ups in period of tight demand. Newbery (2005) discusses these and other extensions, but none of these change the fundamental message of the paper.

---

[21] As defined, the heat rate is the inverse of the thermal efficiency, so for a CCGT of 50% efficiency the heat rate would be 2.

[22] This is not restrictive, given that the emissions per unit of electricity produced is increasing for "coal" units, so oil-fired plants can also be considered with a suitable reinterpretation of the heat rates.

[23] The qualification is that EUAs can be used any time between 1 Jan 2005 and 31 Dec 2007 so the demand and supply should be thought of as 3-year totals selling in theory at a single price, as illustrated in figure 1.

[24] There is a small effect in some hours in that the margin T will change with the change in gas and EUA prices.

Climate change policy and its effect on market power in the gas market

David Newbery
Faculty of Economics, Cambridge
10 November 2005

Note: This earlier version of the paper has been replaced by the version of 16 August, 2006 at the top of this paper). This version has an arithmetic error in the calculation of the mark-up now noted immediately after Table 1

Abstract

The European Emissions Trading Scheme (ETS) limits CO_2 emissions from covered sectors, especially electricity until December 2007, after which a new set of Allowances will be issued. The paper demonstrates that the impact of controlling the quantity rather than the price of carbon is to reduce the elasticity of demand for gas, amplifying the market power of gas suppliers, and also amplifying the impact of gas price increases on the price of electricity. A rough estimate using just British data suggests that this could increase gas market power by 50%.

Key words
Climate change, emissions trading, market power, gas, quotas vs taxes

JEL classification
Q54, Q58, L94

Climate change policy and its effect on market power in the gas market

David Newbery
Faculty of Economics, Cambridge
14 November 2005

Introduction

The European Union has agreed the European Emissions Trading Scheme (ETS) as its principle means of reducing emissions of the main greenhouse gas, carbon dioxide, CO_2. Each year from 2005 until the end of 2007 each country allocates at least 95% of its overall allowances to eligible firms, who are then free to trade them within the EU. The resulting price of an EU Emission Allowance (EUA) for 1 tonne of CO_2 is determined by EU-wide demand and supply of EUAs. At the end of each calendar year covered industries, of which the largest is the electricity supply industry (ESI), must deliver EUAs equal in total to their recorded emissions in that year. EUAs can be held until the end of 2007, at which point a new scheme starts and the old EUAs become worthless.
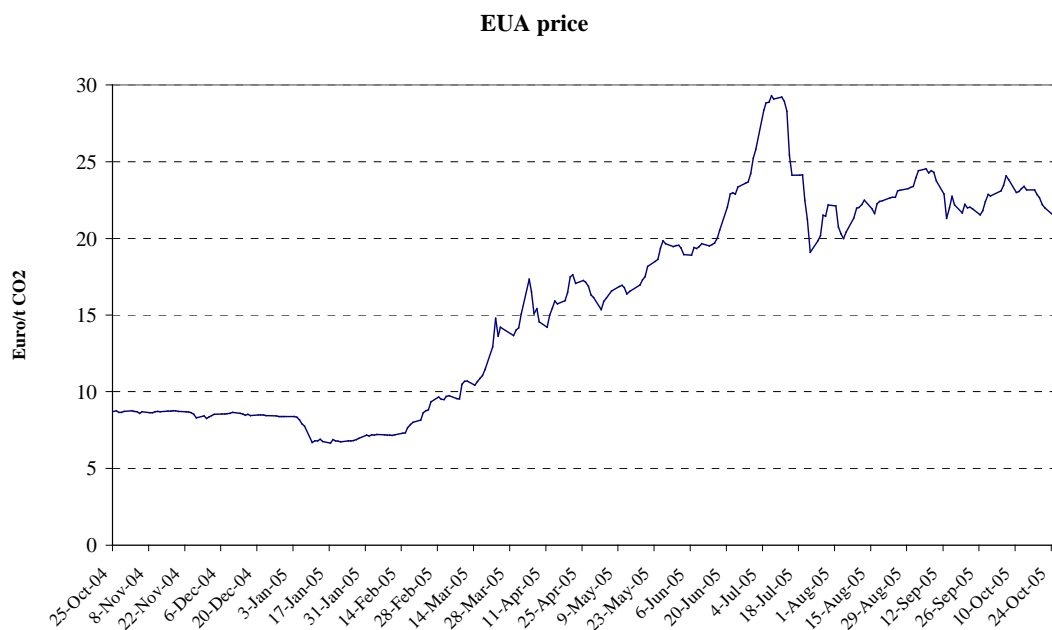

Figure 1 The EU price of CO_2 valid for 2005-2007 (Source: EEX carbon index)

The market for EUAs has been volatile, as figure 1 shows. Moreover, the price of EUAs can be expected to feed through to the wholesale price of electricity in a competitive market, although where final prices are regulated, the price could be held down to offset the windfall profits earned on the allocated EUAs. Some evidence that the EUA price does indeed feed through to the wholesale price is provided by figure 2, 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).

**Spark spread month ahead 50% efficiency**
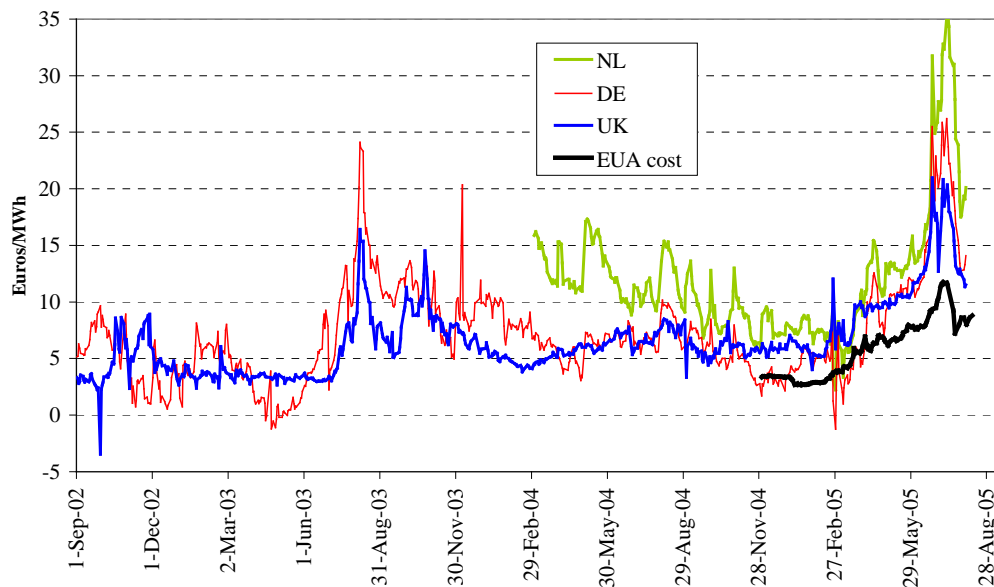
Figure 2 Spark spread and carbon cost in various EU markets (Source Platts)

The striking point that figure 2 hints at is that the price of electricity has risen dramatically in EU countries since the start of emissions trading. Between December 2004 and March 2005 weekly average European base-load prices rose more than doubled from about 35 €/MWh to over 70 €/MWh, prompting a spate of complaints to the European Commission, who in response announced a sector inquiry into gas and electricity in June 2005 (European Commission, 2005).

A considerable part of the price rise could be attributed to a sharp increase in the price of gas, which increasingly sets the peak price in many EU countries. Year-ahead peak prices in Britain rose from about 50 €/MWh in December 2004 to over 90 €/MWh by July 2005 (Platts). However, the European Commission was sceptical that the price increase could be attributed to the normal functioning of competitive fuel markets and noted that network operators favoured their affiliates, that there was little transparency about available capacity and that access charges to gas networks did not appear to reflect costs. This raises two questions – how much of the electricity price rise was caused by the extra (opportunity) cost of CO_2, and to what extent did the presence of the ETS aggravate the effect of market power in gas markets?

The impact on wholesale prices of the obligation to hold EUAs equal to the emissions from 1 January 2005 is shown by subtracting their opportunity cost from the spark spread in figure 3. The visual interpretation is that after an initial period of adjustment the gross profit margin has returned to where it had been, suggesting that most if not all of the EUA opportunity cost has been passed through into the wholesale price.
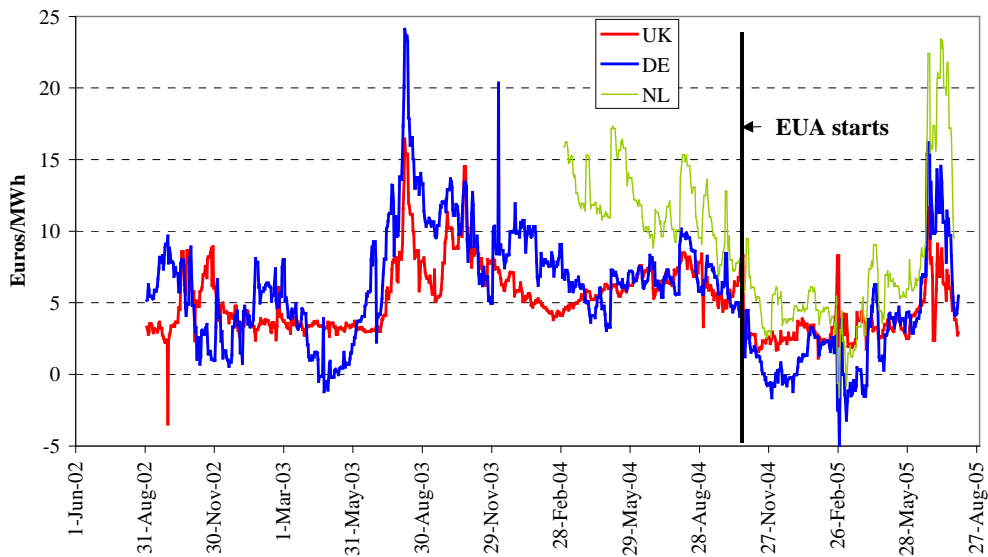
Figure 3 Gross profit of CCGT after paying for fuel and carbon (Source: Platts)

The price of EUAs is determined by supply and demand, and both depend on the extent to which the ESI 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. 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 may amplify the existing market power in the gas market. This paper argues that such concerns should be taken seriously, and that these provide additional good reasons to move away from a quantity-determined climate policy to a price-based approach.

A simple model of pricing EUAs

To gain some insight into possible mechanisms, consider a very simple model in which the price of EUAs is dominated by supply and demand from the electricity supply industry, in the following way. Suppose that the prices of coal and gas are set on world markets and that the cost of coal is c (€/MWh of fuel) and of gas is g. The heat rate for fuel f ($f = c,\ g$) is h_f (MWh of fuel per MWh of electricity generated, or MWhe) so that the variable fuel cost (per MWh) is

$h_f f$ €/MWh.[25] The fuel prices are initially such that the variable generation cost using coal is less than gas: $ch_c < gh_g$. Emissions (tonnes CO_2 per MWh of energy content of fuel) f is e_f, so emissions per MWhe of electricity generated will be $h_f e_f$. If the price of EUAs is s €/t the variable cost, including the opportunity cost of the EUAs, will be $v_f = h_f(f + se_f)$ €/MWhe. For the moment consider periods of the year in which there is enough gas and coal capacity to drive the wholesale price down to the variable cost of generation, but not enough coal capacity alone to meet demand then. If in such periods the price of electricity is p and both technologies are required to meet demand, then the price of EUAs, s, and of electricity, p, must be such that

$$p = h_c\left(c + e_c s\right) = h_g\left(g + e_g s\right). \tag{1}$$

or

$$s = \frac{h_g g - h_c c}{h_c e_c - h_g e_g}. \tag{2}$$

It follows that the price of electricity is

$$p = \frac{h_g h_c\left(e_c g - e_g c\right)}{h_c e_c - h_g e_g}. \tag{3}$$

and that the impact of gas prices on electricity prices is amplified, as

$$\frac{dp}{dg} = \frac{h_g h_c e_c}{h_c e_c - h_g e_g} = h_g\left(\frac{1}{1 - h_g e_g / h_c e_c}\right) > h_g. \tag{4}$$

The partial effect of gas prices on electricity prices holding the price of EUAs constant is just h_g so the effect of the feedback through the market for EUAs is given by the bracketed term, which magnifies the effect. To put some numbers on this suppose that h_g is 2, h_c is 2.65, $e_c = 0.34$ tonnes CO_2/MWh and $e_g = 0.2$ tCO_2/MWh, then the multiplication factor will be 1.8 compared with a market in which the price of gas does not affect the price of EUAs. Interestingly, if coal becomes more efficient relative to gas the multiplier increases. Thus if h_c were to fall to 2.5 the multiplier would become 1.9.

This has interesting implications for the profits of generation companies. Suppose that their baseline output is Q and they are allocated $h_a e_a Q$ EUAs, where $h_a e_a$ is an average emission factor per MWhe corrected by the amount of coverage (e.g. 95%). The profit of the company if it sells q units of electricity is

$$\Pi = pq + sh_a e_a Q - h_g(g + s e_g)\alpha q - h_c(c + s e_c)(1 - \alpha)q = sh_a e_a Q, \tag{5}$$

---

[25] As defined, the heat rate is the inverse of the thermal efficiency, so for a CCGT of 50% efficiency the heat rate would be 2.

during those periods when the arbitrage equation (1) holds (and assuming no inframarginal coal or gas plants) (where α is the share of generation from gas during this period). Again from the price equation (2) for EUAs

$$\frac{d\Pi}{dg} = \frac{e_a h_g Q}{h_c e_c - h_g e_g},$$ (6)

so profits rise with the price of gas. This might give generating companies owned by gas suppliers (e.g. Gas Natural in Spain) an extra incentive to raise the price of gas (although an individual EU gas company might not have as much to gain as a major player like Gazprom). Again, to put some numbers on this, suppose that the baseline allocation is 95% and that the initial share of coal is 80%, then $h_a e_a = 0.722$ tCO$_2$/MWhe and the multiplier of Q in (6) is 1.6.

Another way to examine the incentives to raise gas prices is to examine the demand for gas by the ESI as a function of the EUA price, s. In this overly simple model, at least during hours when there is excess capacity and variable cost pricing, coal and gas plants are perfect substitutes, with the price of EUAs set by the coal and gas prices according to (2). Equilibrium in the market for EUAs will thus depend on the supply of EUAs to the ESI, as in figure 4.
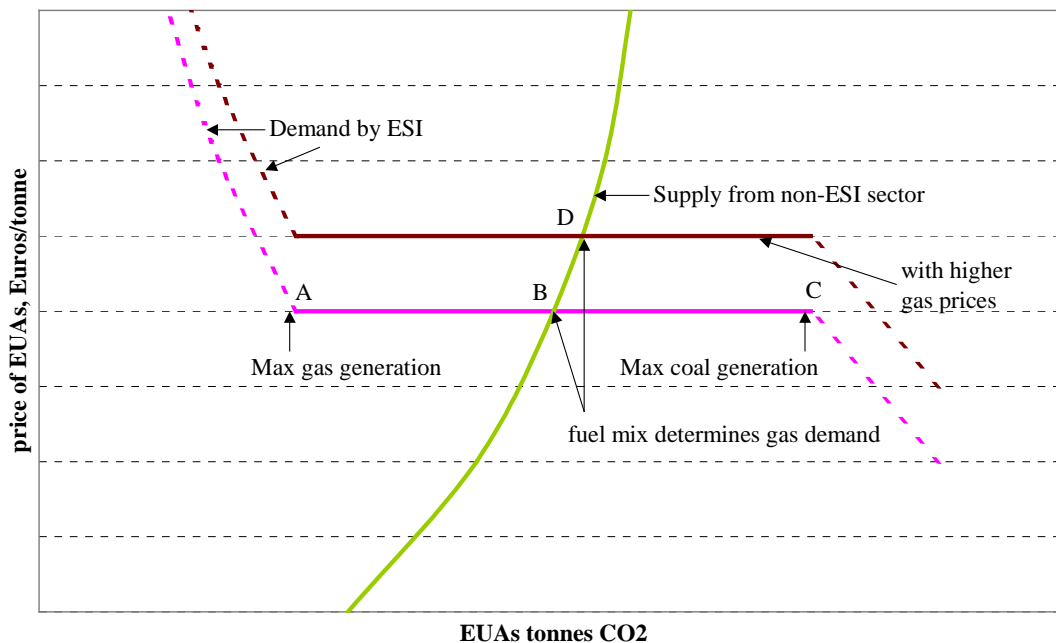
Figure 4 Supply and demand of EUAs in the electricity supply industry

The flat section of the demand for EUAs by the ESI, ABC, shows the range of combinations of coal and gas-fired plant that is capable of meeting demand during these hours, with low emissions requiring all CCGTs to run, at A, and point C corresponding to the minimum gas use and maximum coal use. The actual demand for gas will be set by the intersection of the supply of EUAs from the rest of the economy at point B.

From (2), $ds/dg > 0$, so if the price of gas increases, the whole demand schedule moves up, as in figure 4, and the equilibrium shifts from B to D, which reduces the demand for gas as

coal substitutes for gas (point D is closer to the maximum coal end of the horizontal part of the schedule. It is not immediately clear whether this indirect effect on the demand for gas makes the demand for gas less elastic than without the ETS, and hence amplifies the market power of gas producers, or not. To investigate that we need a more articulated model of the ESI.

A more realistic model

The simple model has a number of obvious drawbacks, in that it only considers periods of excess capacity and pricing at variable cost. While it gives a very direct link between the price of electricity and the prices of the fuels and EUAs, it does not provide a very helpful view of the demand for gas, and it only applies to part of the year. As the carbon price is determined by annual demand and supply it is important to extend the model to cover with varying levels of demand, and in so doing it is possible to develop a more realistic model of the demand for gas, which is our central concern.

To keep matters as simple as possible, assume that the price of carbon has little effect on the demand for electricity (compared to the demand for carbon), and that there are two technologies, gas and coal.[26] Assume that all gas-fired plant is equally efficient but limited in capacity, measured by K_g MW, so the variable cost of gas-fired plant is constant. Coal plants, in contrast, vary in efficiency, and the heat rate of the marginal plant increases with supply. Put another way, older less efficient coal plant is placed lower down the merit order and is only called after more efficient plant. The unsubscripted heat rate now refers to coal and is a function of its position in the merit order, with $h(K)$ the heat rate of the marginal coal plant of the most efficient K MW of coal plant, $K < K_c$, the total coal capacity. The simplest such model would have $h(K) = h_0 + \alpha K$, (where α has dimensions MW^{-1}) giving a linear increasing marginal cost schedule.

The merit order will now depend on the prices of coal, gas and EUAs. The variable (or marginal) cost of CCGT will be, as before, $v_g = h_g(g + se_g)$. The marginal cost of coal-fired plant is a function of K: $v(K) = h(K)(c + se_c)$, which will be linear if the heat rate is linear: $v(K) = (h_0 + \alpha K)(c + se_c)$. The interesting case has some coal plant cheaper than gas, but older plant more expensive, or $h_0(c + se_c) < h_g(g + se_g) < (h_0 + \alpha K^*)(c + se_c)$, where if D^* is peak demand, $K^* = D^* - K_g$. (Other cases are discussed in the Appendix.) Suppose the load duration curve is given by $D(t) = b + \mu(1-t)$, where t is the fraction of the year that demand is higher than $D(t)$ MW and both b and μ are measured in MW, as shown in figure 5. Given the capacity of CCGT, $D^* = D(0) = b + \mu = K^* + K_g$ (so $K^* = b + \mu - K_g$).

---

[26] This is not restrictive, given that the emissions per unit of electricity produced is increasing for "coal" units, so oil-fired plants can also be considered with a suitable reinterpretation of the heat rates.
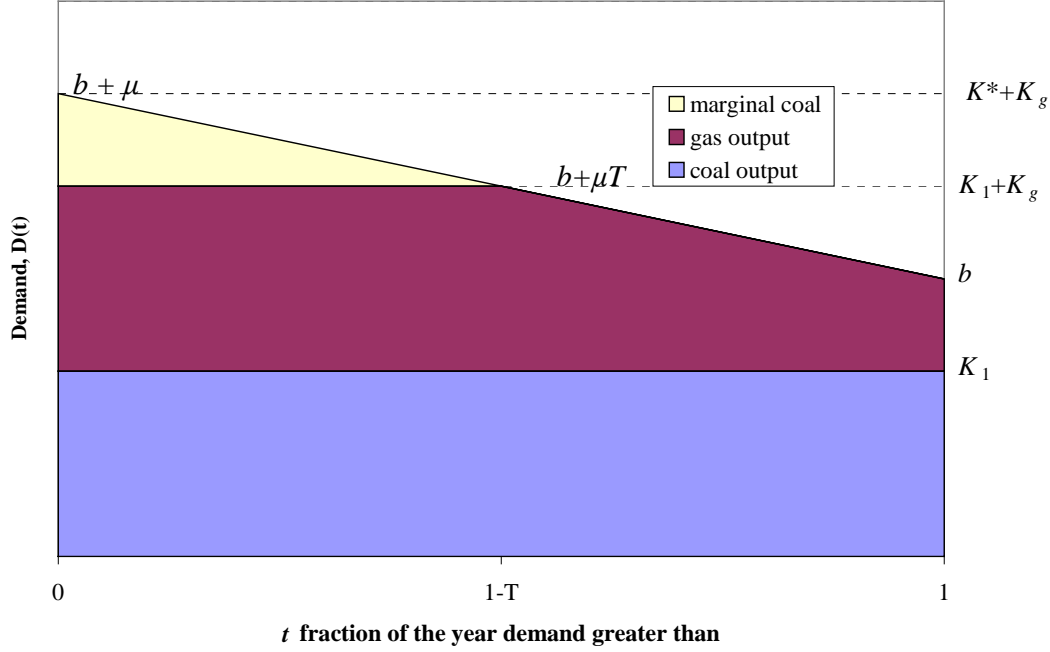
Figure 5 Load duration curve and shares of generation from each fuel

The merit order determines how many hours each plant runs and therefore generates and emits. Suppose that the lowest load factor CCGT runs a fraction T of the year, then one possible configuration of the merit order has K_1 units of coal plant running on base-load, followed by $b - K_1$ units of CCGT running base-load and the remaining μT MW of CCGTs running mid-merit, with the $\mu(1-T)$ units of higher cost coal supplying the peak, as in figure 5. The value of K_1 is such that the marginal costs are there equal, so

$$(h_0 + \alpha K_1)(c + se_c) = h_g(g + se_g),$$

or

$$K_1 = \frac{h_g(g + se_g)}{\alpha(c + se_c)} - \frac{h_0}{\alpha}. \tag{7}$$

The value of T then solves $b + \mu T = K_1 + K_g$, or $T = (K_1 + K_g - b)/\mu$. The total generation of gas-fired electricity is found by geometry from figure 1 to be the base-load and mid merit outputs: $Q_g = b - K_1 + \frac{1}{2}\mu T(2-T)$ MW years. Emissions from gas-fired plant are $E_g = 8760\, h_g e_g Q_g$. Total coal-fired generation is $Q_c = K_1 + \frac{1}{2}\mu(1-T)^2$ MW years, but emissions will vary with the plant dispatched, and must be found by integration:

$$E_c = 8760\, e_c \left(\int_0^{K_1} h(q)dq + \frac{1}{\mu} \int_{K_1}^{K*} (K*-q)h(q)dq \right) = E_c(K_1). \tag{8}$$

As the price of EUAs increases, so the volume of base-load coal plant, K_1, decreases as gas is favoured in the merit order, increasing its share of total generation and thus displacing more carbon-intensive coal. Total emissions, $E = E_g + E_c$, are therefore a

decreasing function of the EUA price, *s*. If the supply schedule of EUAs from other sectors supplied to the market is increasing in *s*, the equilibrium value of *s* will be determined by the intersection of supply and demand.[27] If the price of coal is assumed constant, then the price of EUAs will depend on the price of gas.

Exercising market power in the gas market

The demand for gas from the ESI will depend on its price, the price of coal (which is assumed constant and independent of demand), and the price of EUAs, which is in turn determined by the prices of fuels. The main question to be addressed is whether the particular form of the ETS amplifies, mitigates, or is neutral to the exercise of market power by gas suppliers. To simplify, suppose the supply of EUAs to the ESI, $S(s)$, depends on the price of EUAs only and not on the price of gas. (This assumption can be relaxed without changing the direction of the results, but at the cost of greater complexity in modelling the EUA market.)

The ESI demand for gas is $G = 8760h_gQ_g = \theta Q_g$, which is a function of K_1, so $dG/dg = \theta(dQ_g/dK_1).(dK_1/dg)$. For the merit order shown in Figure 5, $dQ_g/dK_1 = -T$. The crucial derivative is therefore dK_1/dg, which from (7) is

$$\frac{dK_1}{dg} = \frac{\partial K_1}{\partial g} + \frac{\partial K_1}{\partial s}\frac{ds}{dg} \quad . \tag{9}$$

The value of *ds/dg* can be found by examining the intersection of the demand for and supply of EUAs to the ESI. The demand for EUAs by the ESI is a function of the price of gas and of EUAs, $E\{K_1(g,s)\}$, whereas the supply is just a function of the EUA price, $S(s)$. Equilibrium in the market for EUAs is found from $S(s) = E\{K_1(g,s)\}$. Differentiate this totally with respect to the gas price, *g*:

$$\frac{\partial S}{\partial s}\frac{ds}{dg} = \frac{\partial E}{\partial K_1}\left(\frac{\partial K_1}{\partial g} + \frac{\partial K_1}{\partial s}\frac{ds}{dg}\right),$$

or, rearranging and simplifying

$$\frac{ds}{dg} = \frac{\dfrac{\partial K_1}{\partial g}\Big/\dfrac{\partial K_1}{\partial s}}{\dfrac{\partial S}{\partial s}\Big/\left(\dfrac{\partial E}{\partial K_1}\dfrac{\partial K_1}{\partial s}\right)-1} \quad .$$

This can now be inserted into equation (9) to give

---

[27] The qualification is that EUAs can be used any time between 1 Jan 2005 and 31 Dec 2007 so the demand and supply should be thought of as 3-year totals selling in theory at a single price.

$$\frac{dK_1}{dg} = \frac{\partial K_1}{\partial g}\left(1 - \frac{1}{1 - \frac{\partial S}{\partial s}\bigg/\left(\frac{\partial E}{\partial K_1}\frac{\partial K_1}{\partial s}\right)}\right). \tag{10}$$

The various terms can now be derived from (8) as follows:

$$\frac{\partial E_c}{\partial K_1} = 8760\, e_c\left(h(K_1) - \frac{1}{\mu}(K^* - K_1)h(K_1)\right) = 8760\, e_c\, h(K_1)T,$$

which makes use of the relation $K^*-K_1 = \mu(1-T)$. Given the equation for $E_g = 8760\, h_g e_g Q_g$, the full derivative is:

$$\frac{\partial E}{\partial K_1} = 8760T\big(e_c\, h(K_1) - e_g\, h_g\big) > 0. \tag{11}$$

The term $\partial K_1/\partial s$ is found from (7) to be

$$\frac{\partial K_1}{\partial s} = -\frac{h_g(e_c\, g - e_g\, c)}{\alpha(c + se_c)^2} < 0. \tag{12}$$

If the elasticity of supply of EUAs to the ESI is η, then $\partial S/\partial s = \eta E/s$, and all the necessary elements are now available to calculate the elasticity of ESI demand for gas with the ETS:

$$\varepsilon^* = \frac{g}{G}\frac{dG}{dg} = \frac{-\theta T}{\theta Q_g}\frac{g}{dg}\frac{dK_1}{dg}\ . \tag{13}$$

The elasticity without the ETS (or with the price of EUAs independent of the price of gas), ε, is found by replacing dG/dg by $\partial G/\partial g$. The ratio of the elasticity with and without the ETS is then given from (10) as

$$\frac{\varepsilon^*}{\varepsilon} = \left(\frac{\eta}{\eta + \phi}\right), \quad \phi \equiv \left(\frac{K_1\partial E}{E\partial K_1}\right)\left(\frac{-s\partial K_1}{K_1\partial s}\right). \tag{14}$$

For example, if we roughly calibrate this for Britain in 2005 with the parameters shown in table 1.

Table 1 Parameters for calibrating the model to Britain, 2005

gas heat rate	h_g	2
coal base heat rate	h_0	2.5
rate of change of HR	α	0.025 per GW
CO_2 per MW gas	e_g	0.2 tonnes/MWh
CO_2 per MW coal	e_c	0.34 tonnes/MWh
min demand	b	25 GW
Slope of load duration	μ	30 GW
gas capacity	K_g	20 GW
coal capacity	K_c	40 GW
Price of gas	g	16 €/MWh
Price of coal	c	6 €/MWh
EUA price	s	20 €/tonne CO_2

Given these values, φ = 0.55. If the elasticity of EUA supply, η, is 0.1 then the elasticity of gas demand is reduced to two-thirds its unconstrained value, and the Lerner Index (the markup as a fraction of the price) will be increased by 50%. [**Note – the elasticity is actually reduced to 15% of its former value and the Lerner Index increases by a factor 6.5 – see the discussion in the version of August.**]

The effect of an increase in gas price on the demand for (and hence price of) EUAs is unambiguous. Higher gas prices move gas down the merit order (and up the load duration schedule in figure 5) and reduce gas-fired generation, increasing emissions and hence increasing the demand for EUAs, raising their price and magnifying the impact of the gas price rise on the price of electricity. Equation (14) shows that the effect of carbon trading is to *reduce* the elasticity of demand for gas, *amplifiying* the market power of the gas supplier.

Policy implications

The amplification of market power works through the impact on the price of EUAs, which, as gas prices rise and lead to coal substituting for gas, raise emissions and hence the price of EUAs, which in turn favours gas, offsetting the normal market demand response to an increase in the price of gas. As the EU gas market is thought to be less competitive than either the electricity or coal market, and as Gazprom clearly has some market power, it seems desirable to find ways of addressing climate change without exacerbating these other market failures, particularly where the result is not just a redistribution of income between gas companies and consumers within the EU (as well as extra deadweight losses) but also an increased transfer to gas producers outside the EU.

The obvious solution is to cut the link between the demand for EUAs and their price by fixing the price of the EUAs. This could be done either by the European Commission (or some body) being prepared to buy and sell any number of EUAs at the fixed price, or by replacing the ETS by a fixed carbon tax per tonne of carbon burned. The former is likely to be politically more attractive than the latter, and can be made cash positive or neutral to the

EC by suitable reductions in the allocations of EUAs each year. A similar proposal termed the "safety valve" is discussed by Jacoby and Ellerman (2004)..

There are additional arguments for setting the price of carbon and allowing the market to determine emissions, rather than setting the quantity and allowing the market to determine the price, all deriving from the insights of Weitzman's seminal paper on prices vs. quantitites. Weitzman (1974) started a lengthy debate by observing that in the presence of uncertainty, permits are only superior to taxes if the marginal benefit schedule had more curvature than the marginal abatement schedule. This might be the case if marginal damage were low until some threshold level, at which point it suddenly increases. For most pollutants the marginal abatement cost schedule is fairly flat and low for modest abatement, but rises rapidly as a higher fraction of emissions is to be curtailed, arguing for taxes rather than quotas. The damage contributed by emissions today is effectively the same as those tomorrow, and so the marginal benefit of abatement is essentially flat at each moment, while the marginal cost of abatement rises rapidly beyond a certain point.

The scale of the hazard of global warming is very uncertain, as are the future costs of reducing carbon intensity. All these provide additional arguments for a carbon tax (or fixed price) rather than tradable permits. Hoel and Karp (2001) explore this question more carefully in a calibrated linear-quadratic dynamic model of global warming and confirm this claim robustly. Karp and Zhang (2004) extend the analysis, taking account of the stock nature of CO_2 emissions and uncertainty about costs, but also taking account of asymmetric information about the costs of abatement and learning about the cost of global warming. Again they find that taxes are superior to quotas or tradable permits.

Extensions

The simple model gave a direct link between the electricity price and the price of gas and EUAs, as it only studied periods of excess capacity and variable cost pricing. The more realistic merit order model can derive the impact of gas prices on variable costs for each level of demand, but needs an extension to properly model the impact on electricity prices. A more complete model would also look at the recovery of fixed costs via the conditions (and cost) of entry and the required reserve margin, which will affect the wholesale price. During periods when the price is dominated by the variable cost (low price periods of excess supply, covering in figure 5 the lowest fraction *T* of the year), the effect is straightforward:

$$\frac{dv_g}{dg} = h_g (1 + e_g \frac{ds}{dg}).$$

The first term is the direct impact of gas prices on the variable cost, which should feed directly through to the wholesale price, but as in the first model the effect is magnified by the second term, which is positive. The same is true for the most expensive 1-*T* fraction of the year in figure 5, when coal is at the margin. There will be an additional term $e_c.ds/dg$

increasing the effect (which would otherwise be zero, as the same coal-plant would be at the margin in the top 1-T fraction of the year).[28]

The impact on wholesale prices will be made up of the impact on the variable cost and on the capacity charge. If CCGT were the preferred investment before and after the price change there should be no effect on the capacity cost and hence on the extra capacity charge in the wholesale price. If gas prices are so magnified by the ETS that coal becomes preferred, then capacity costs would be higher and the capacity charge might have to increase. Whether this is likely might depend on the response of gas suppliers. On the one hand, the demand for gas has been made less elastic by the ETS, allowing gas suppliers to raise prices more for a given reduction in gas, and so arguably making it less likely that gas supplies would fall so much as to require coal to displace gas for new investment. On the other hand, governments may feel that to counter the increased market power of gas suppliers, coal should be favoured by the system of allocating new EUAs. If the EUA price were capped that argument might be more effectively countered.

Conclusions

The ETS restricts total emissions of CO_2 and determines their price (until 2007) by market trading. As a result the price is volatile (although trading between years reduces this volatility somewhat. This volatility is costly in a variety of ways, not least in making investment decisions more risky and therefore the cost of capital higher. There are powerful arguments for preferring a climate change policy that stabilises the price of EUAs (or greenhouse gases, GHGs, more generally), based on the stock nature of GHG emissions, and given uncertainties and ignorance about the nature of the costs of mitigation and of climate change. This paper has advanced an additional argument in favour of setting the price of EUAs rather than the quantity, in that CO_2 quotas rather than taxes amplify the damaging effects of imperfect competition in the gas market.

It is well-known that tariffs and quotas are not equivalent in the presence of imperfect competition in domestic markets (Bhagwati, 1965), and that under certainty, tariffs are superior (in the strong sense that an optimal tariff would be better than the optimal quota). The reason is simple – a binding quota limits imports of competing products and makes the residual demand facing the home supplier less elastic than would be the case if imports were subject to a tariff. It is also well-known that demand is less elastic in the presence of rationing, even where the rationing applies to other markets than the one under study (Neary and Roberts, 1980). This in turn is an illustration of the Le Chatelier Principle that constraints reduce the elasticity of response, as noted by Samuelson (1947) and set out in standard textbooks (e.g Varian, 1984, p56). The same applies if the quantity of EUAs is fixed, as this reduces the elasticity of demand for gas and enhances the market power of those selling gas, including large foreign suppliers such as Gazprom.

---

[28] There is a small effect in some hours in that the margin T will change with the change in gas and EUA prices.

The political advantages of the current ETS should not be underestimated, and these need to be retained when designing the next phase to start in 2008. The preferred solution would be to agree a price for GHGs, and for the European Commission to be willing to sell any demanded and not supplied by the market, or to intervene to buy back surplus EUAs. The allowances to be allocated free should be scaled back so that the risk of the EC having to buy back EUAs is reduced to very low levels. There may then be a good case for eliminating the discontinuity at the end of 2007 by extending the price-setting mechanism into the first period. As better information about EU GHG supply and demand, and about the costs and benefits of reducing GHG emissions, arrives, so the intervention price can be modified, although there are probably good arguments for issuing long-term contracts for differences on the prevailing price to provide greater certainty for low-carbon investments.

References

Bhagwati, Jagdish, (1965) 'On the Equivalence of Tariffs and Quotas' in *Trade, Growth, and Balance of Payments: Essays in Honor of Gottfried Haberler*, editors: R.E. Baldwin et.al. Chicago.

European Commission (2005) *The Week in Europe* 17 June 2005 available at http://www.cec.org.uk/press/we/we05/pdf/we0523.pdf

Hoel, M. and L. Karp (2001) "Taxes and quotas for a stock pollutant with multiplicative uncertainty" *Journal of Public Economics*, 83, 91-114

H. D. Jacoby and A. D. Ellerman, The safety valve and climate policy, Energy Policy, 32 (4) 2004, 481-491

Karp, L. and J. Zhang (2004) "Regulation with anticipated learning about environmental damages", University of California, Berkeley

Neary, J.P and K.W.S. Roberts, (1980) 'The Theory of Household Behaviour under Rationing' European Economic Review. 13(1): 25-42

Newbery, D.M. (2005) 'Why tax energy? Towards a more rational policy**,** *Energy Journal*, **26** (3), 1-39

Platts reporting services, http://www.platts.com

Samuelson, P.A. (1947) *Foundations of Economic Analysis,* Camrbndge Mass: Harvard

Varian, H.R. (1984) *Microeconomic Analysis¸* New York: Norton

Weitzman, M.L. (1974) "Prices vs. Quantities", *Rev. Econ. Stud.* **41** (4), 477-91

Appendix Other configurations of the merit order

If the price of gas is low enough, then gas will run base-load before any coal. The condition for this is given by K_1 in (7) being zero or negative, or

$$g < \frac{h_0(c + se_c)}{h_g} - se_g . \tag{A1}$$

In this case, total gas-fired generation and total emissions from gas will be independent of the price of gas and the EUA price until condition (A1) is violated, in which case we return to the case discussed in the text. Over this initial range of (low) gas prices, the EUA price would not respond to the price of gas and hence the amplification effect discussed in the paper would initially be absent.

As the price of gas rises further, so will K_1 until it exceeds b as shown in figure A1. This complicates the derivation of responses, as there are now two margins for gas, but it does not alter the conclusion, which appears remarkably robust.
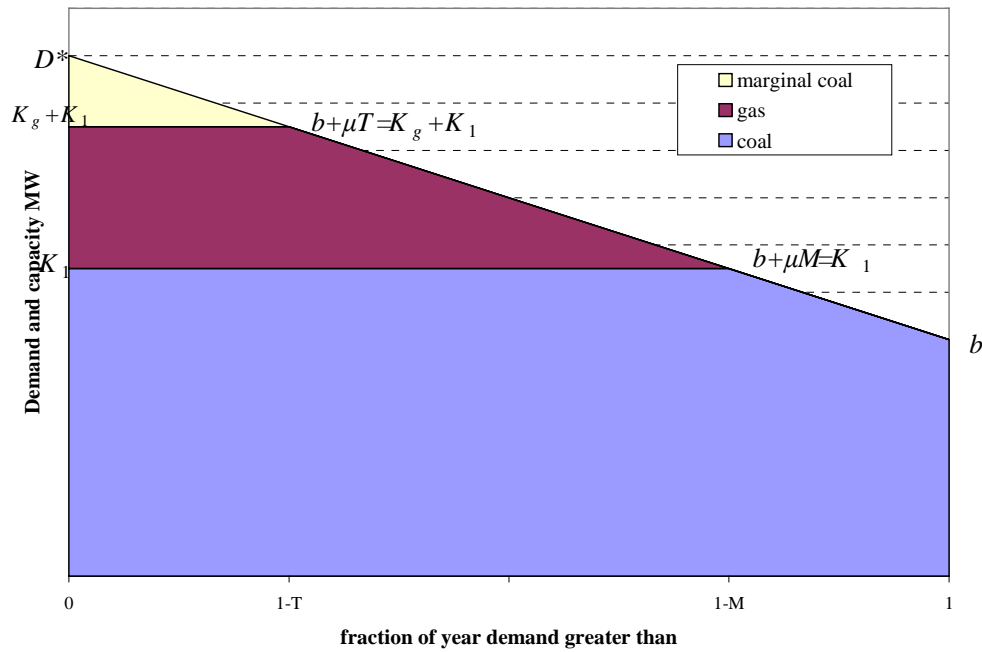

Figure A1 Gas entirely off base-load

At even higher prices of gas gas-fired generation might move down the merit order (i.e. run less and appear at the top of the load duration curve), but as before the links in the chain of reasoning between gas price, gas demand and the mitigating effect through the price of EUAs will continue (but with different numerical values). The volume of gas-fired generation will be

$$Q_g = K_g(1 - \tfrac{1}{2}(T + M)) = K_g\left(\frac{\mu + b - K_1 - \tfrac{1}{2}K_g}{\mu}\right), \tag{A2}$$

As before, $dG/dg=\theta(dQ_g/dK_1).(dK_1/dg)$. For the merit order shown in Figure A1 and from (A2), $dQ_g/dK_1 = -K_g/\mu$, which has the same sign as, and is similar to, the merit order case of figure 5, where $dQ_g/dK_1 = - (K_1 + K_g - b)/\mu$. The effect on the ratio of gas demand elasticities remains $(dK_1/dg)/(\partial K_1/\partial g)$ and this is not affected by the form of Q_g, although the terms in (14) will need to be recomputed. Using the same techniques as before, $\partial E_c/\partial K_1 = 8760e_ch(K_1)K_g/\mu$, so $\partial E/\partial K_1 = 8760K_g/\mu\{e_ch(K_1) - h_ge_g\} > 0$. This is the same as (11) multiplied by $K_g/\mu T$. As the formula for $\partial K_1/\partial s$ is unchanged, the value of φ is also multiplied by $K_g/\mu T$, which with the parameters of Table 1 is slightly less than 0.5 (although of course, the gas price would have to change, and that would also have an effect). In general one would expect the elasticity to be less affected by the ETS as gas became a smaller share of generation.
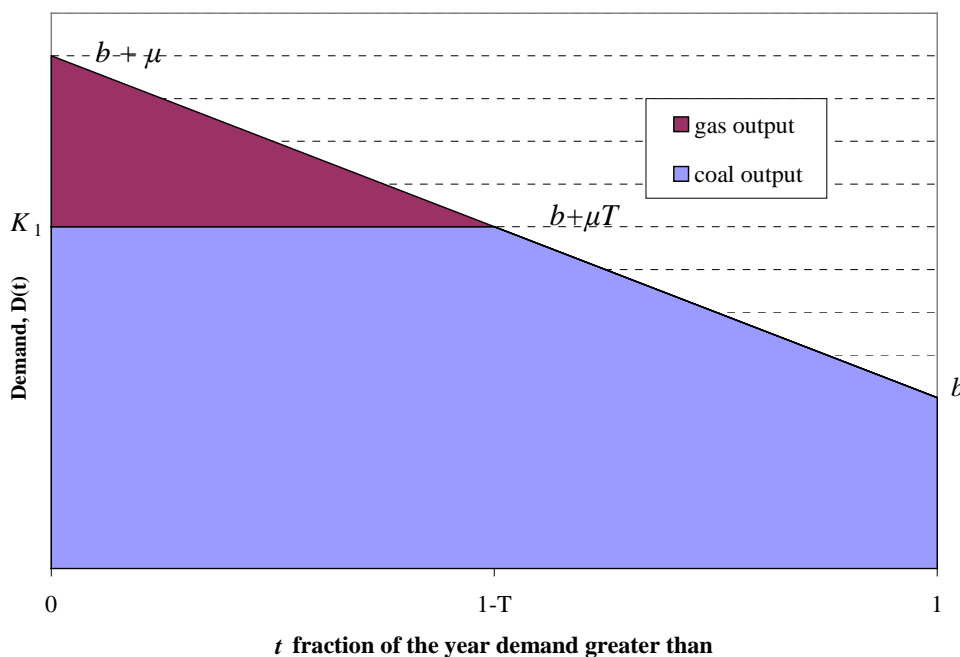
Figure A2 CCGT mid merit and peaking

The situation shown in figure A2 again has K_1 determined by (7) (assuming that the solution $K_1 \leq K_c$) but the amount of gas capacity actually needed is $\mu(1-T) \leq K_g$ so that $T = (b - K_1)/\mu$. Gas-fired output is $Q_g = \frac{1}{2}\mu(1-T)^2$ so that $dQ_g/dK_1 = (1-T)$, which this time is positive. However, $\partial E/\partial K_1 = 8760(1-T)\{e_ch(K_1) - h_ge_g\} > 0$, this time multiplying φ by $(1- T)/T$. Qualitatively, the results do not change, although the changing gas prices needed to produce these configurations will affect the numerical results.