The impact of low carbon generation on the future price of electricity

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There are relatively few who would argue that tackling climate change, and therefore reducing carbon emissions, should not be a priority for society and the energy sector. But significant increases in energy prices are a necessary consequence of that policy. Using published sources this paper estimates that by 2020 UK and EU regulatory mechanisms designed to promote lower carbon energy will increase average household electricity prices by between 23% and 42%, and median industrial electricity prices by between 30% and 60%.

Achieving Scottish and UK climate change targets will require a major expansion of low carbon electricity generation – with a consequent investment of £ billions over the next 2 decades or so. The UK government's expectation is that this investment will very largely be delivered by the commercial sector – whether the investment is in renewable energy, cleaner use of fossil fuels, nuclear power, or development of related infrastructure (such as extension and reinforcement of the electricity grid). The implication of delivering cleaner energy through commercial investment is that the full costs of delivering a lower carbon future will be passed through to consumers in the form of higher electricity prices – and that this increase in prices can probably be expected to at least last the lifetime of the next generation of power stations (30 years or more). In addition some lower carbon technologies (such as renewable energy, or carbon capture and storage for fossil fuelled power stations) are expected to require significant ongoing subsidy to make returns attractive to commercial investors. The mechanisms favoured by the government (such as the renewables obligation, carbon trading, and regulatory intervention) all mean the additional costs of any subsidy required for cleaner electricity will be passed on to consumers (rather than alternative mechanisms than would use taxation to redistribute the costs). As industrial electricity prices are around 30% lower than household electricity prices, if the price increases are distributed evenly across all electricity consumers, the percentage increase in industrial energy bills will be greater than the increase in household energy bills.

Just to be clear, the costs of reducing the carbon impact of electricity are all additional to future price increases that could occur due to underlying increases in the costs of the main primary fuels used in electricity generation (coal, gas, and uranium). Increases in primary fuel prices (due in part to increased demand from fast growing economies such China and India) have already resulted in an average 46% increase in retail electricity prices in the UK since 2005[1].

In an interview in the Financial Times on 4 June 2008, Paul Golby, the chief executive of one of the UK's major generators, Eon, warned that consumers needed to prepare themselves for structurally higher prices in order to meet the requirement for new investment in nuclear power stations and renewable energy, and to replace existing aging energy infrastructure. He suggested that investment in energy infrastructure in the UK could reach £100 billion or more by 2020. The UK is not in an unusual position – the International Energy Agency projects that $17 trillion investment is needed in energy infrastructure by 2030[2].

Given that there is a GB electricity market these additional costs will tend to be spread across all GB consumers – no matter whether investment in new cleaner generation is being made in Scotland, England, or Wales. The Scottish Government has devolved powers which would allow it to vary policies in relation to the renewables obligation and carbon trading. However the GB-wide electricity market, and the EU-wide trading mechanism for carbon emissions, would tend to level out differences in the costs of policies across all GB consumers, and it would therefore seem unlikely in current circumstances that different Scottish policies would result in significant differentiation of electricity prices in Scotland from those elsewhere in the UK.

The size of the challenge

Both the UK and Scotland are setting ambitious targets for reducing carbon emissions. The UK Government is committed to reducing carbon emissions by 60% by 2050, and the Scottish Government has consulted on a target to deliver an 80% reduction in carbon emissions by 2050[3]. The energy sector is responsible for 36% of UK carbon emissions[4], and in Scotland the three main fossil fuelled power stations (Longannet, Cockenzie, and Peterhead) typically emit around 35% of Scotland's total net carbon emissions (with Longannet being the largest of these)[5]. Power generation is the largest single contributor to UK and Scottish carbon emissions. Due to the size and nature of its emissions (from a relatively small number of large, easily identified and monitored sources), and the industry's ability to pass through the costs of new investment to consumers, the power generation industry has been for some time one of the major targets of regulatory action to reduce carbon emissions at both European and member state level. By their nature, emissions from the transport and the domestic sector are more difficult to target effectively - and therefore the power sector can expect to be a major target for governmental carbon reduction initiatives for decades to come.

Renewable energy support

Currently most forms of renewable generation would not be commercially viable without some form of additional financial support[6]. The main method used by the UK and Scottish Governments to support the development of renewable electricity is the Renewables Obligation (or RO). The RO places an obligation on UK suppliers to source a proportion of their electricity from renewable sources. This proportion increases every year – and for 2008-09 is 9.1%[7] Suppliers effectively meet this obligation through generating renewable electricity, or purchasing it from other generators, or by paying a buy out price for any shortfall. Generators are issued Renewable Obligation Certificates (ROCs) in proportion to the amount of renewable electricity they generate. The price of a ROC (1 ROC is issued for each MWh generated) is determined by the total amount of renewable generation in the UK, and the gap between this and the obligation level set by the RO. In 2006-07 the total value of a single ROC to a supplier was £49.28[8].

The total value of ROCs to suppliers in 2006/07 was over £700 million. 35% of these ROCs were earned by generation facilities located in Scotland. The costs of this subsidy are passed on to consumers throughout the UK via their electricity bills - currently representing around 2.5% of a typical electricity bill. As the level of the RO increases so will the costs to consumers. Analysis by Ofgem[9] suggests that by 2020 the total cost of the RO will have increased to around £2.7 billion per annum – and will represent around 10% of the average bill by 2020 – representing a 7.5% increase in consumer electricity prices (this is similar to the 7% increase estimated by the UK Energy White Paper).

In order to maintain investor confidence the UK Energy White Paper "Meeting the Energy Challenge" committed the UK Government to retaining the renewables obligation until 2027 – so the cost of the RO will be met by consumers, and is likely to continue to increase, for at least 20 years.

Ofgem has called on the UK Government to examine other methods of subsidising renewable generation. It estimates that the RO mechanism costs £63-140 per tonne of CO_2 abated (a similar estimate to that produced by the NAO) – and notes that carbon abatement is currently available at much lower costs through mechanisms such as the EU Emissions Trading Scheme (see below). It should be noted however that this ignores other arguments for the development of renewables – such as the potential to export renewable technologies to other countries (though there are other support mechanisms specifically designed to promote research, development and demonstration of new clean energy technologies – so the question would remain as to whether the RO is the most effective means of achieving this goal).

Grid enhancement

Scotland and the UK have significant renewable energy resources – in the form of wind, wave and tidal energy. However much of this resource is distant from the main centres of population. The existing electricity grid was built to support a system of centralised generation – with power stations located close to centres of population – and transmission and distribution systems constructed to support lower electricity loads in more sparsely populated areas. Capturing renewable energy in significant amounts, and transmitting it to centres of population, will require significant investment in the extension and reinforcement of the electricity grid. These costs and their recovery is regulated by Ofgem, and are passed on to consumers through their electricity bills.

Transmission and distribution charges are reviewed every 5 years. In the current period Ofgem has authorised over £10 billion to be spent on ensuring electricity networks deliver a reliable service and can expand to meet the needs of renewable energy. This represents a 48% increase in expenditure on distribution networks over the previous review period, and a 125% increase in expenditure on transmission networks. This represents an extra 1.5% on average domestic electricity bills[10].

Studies predict that significant additional expenditure on the grid will be required to support future development of renewable energy[11]. Though the amount of investment required is currently difficult to quantify. The UK Energy White Paper[12] acknowledges that the development of renewable energy will require significant further investment in transmission infrastructure – but states that no detailed studies have been undertaken to estimate the future costs of enhancement. Given that all parties appear to agree that significant further investment will be necessary this paper has made an assumption that the need for additional investment in the grid will continue at the current rate until 2020 – and will therefore result in a 3% increase in domestic energy bills over that period (however it should be noted that there is no detailed analysis underlying this assumption – the real figure could be higher or lower).

Tackling intermittency

Demand for electricity varies significantly by time of day and time of year – as domestic and industrial heating and lighting requirements change. Typically peak demand will occur at around 6.30 pm on a cold winter's day – and will be just under 3 times the demand experienced at around 5.30 am on a summer's day.[13] Generators and the National Grid use a portfolio of generation options (switching the level of generation from a mix of different types of power stations), and regulatory and energy trading systems, to match electricity supply to consumer demand. However most forms of renewable energy are not controllable – ie they cannot be switched on at will if the primary energy source (eg wind, wave, tide, sunlight) on which they rely is not available at that time. This is not a problem when renewable energy is a relatively low proportion of total generation (as other forms of generation can easily compensate for the variation in renewable generation) – but could become an issue as renewable energy begins to make up a larger proportion of generation. There are solutions available. Energy generated from renewable sources can be stored – e.g. through pumped storage, battery systems, or hydrogen. However technical and commercial factors currently limit the use of electricity storage on large scale. Therefore a significant amount of thermal generation is likely to be required as a reserve – with fossil-fuel power stations kept "hot" and available to run at short notice. But energy storage, back-up generation, and additional contractual balancing mechanisms do not come at zero cost – large energy storage systems would require significant capital investment, and generators will seek compensation for the capital and operating costs of power stations used as back-up. These costs will be passed through to consumers. UKERC made a comparative study of over 200 earlier studies into the costs of intermittency[14] – and estimated that for a 20% penetration of intermittent generation (predominantly wind) in the UK meeting the costs of intermittency would require a 1 to 1.5% increase in household electricity bills.

Carbon capture and storage

As mentioned above, power plants are very significant emitters of carbon dioxide – with Scotland's three largest power stations (Longannet, Cockenzie, and Peterhead) – producing around 35% of Scotland's net carbon emissions. Carbon Capture and Storage (CCS) is a process in which carbon dioxide emissions are captured from the flue gases from power plants or other facilities – reducing their carbon emissions by around 90%. The carbon dioxide is then stored permanently – usually in some type of geological structure, such as a depleted oil and gas reservoir. CCS has the potential to enable very large reductions in CO_2 emissions from electricity generators and major industrial energy users – and currently it appears that CCS will need to be an element of both UK and Scottish approaches to meeting climate change targets. The EU has also set an objective of new fossil-fuel power plants deploying CCS by 2020 (if possible).[15]

However CCS faces a number of significant challenges:

- the technologies are often innovative;
- the costs for any single CCS project are very large;
- achieving a commercial rate of return on early CCS projects appears unlikely;
- the infrastructure to support CCS projects by and large does not exist;
- the regulatory environment is currently uncertain;
- commercial operators are unlikely to be willing to pick up the long term liability for carbon stores (though it appears this liability may be accepted by UK Government);
- the best potential locations for carbon stores in Scotland and the UK have not yet been identified and assessed.

Overcoming these barriers will require joint action from industry, government (UK, Scottish, and European) and regulators – and a mechanism to deliver significant financial support. CCS generating plants incur significantly higher costs due to:

- increased fuel consumption (perhaps 25% higher to deliver the equivalent power output to a non-CCS plant);
- capital investment in carbon capture equipment;
- capital investment in carbon transportation;
- capital investment in carbon storage;
- increased operational costs due to the above infrastructure and activities.

Given that coal-fired plants generally emit significantly more CO_2 per MWh than gas-fired generation there is normally significantly greater environmental benefit in fitting CCS to coal-fired power stations. For example, Scotland's two coal-fired stations (Longannet and Cockenzie) emit around 30% of Scotland's total net carbon emissions.

Studies have produced a broad range of estimates for the additional costs of electricity from CCS facilities. A report from energy consultants Poyry[16] suggested that coal fired CCS plants would incur additional costs of around £22 per tonne of CO_2 (equivalent to around £22.3 per MWh). But given the early state of the CCS industry such estimates may prove to have significant inaccuracies.

The additional costs of CCS could be met through a range of mechanisms – and these would need to offer support to CCS facilities for 20 years or more. Should the EU Emissions Trading Scheme (see below) deliver high carbon prices – and be able to guarantee these prices over a long time-period (something that it has failed to deliver so far) – then this mechanism could fund the development of CCS in power plants. In this case the costs of deploying CCS would not be additional to the costs of the EU ETS set out below.

Another option for funding CCS would be regulation requiring CCS to be fitted to all fossil-fuelled power stations. This would allow energy companies to pass the full costs on to consumers – but might be a high-risk approach for governments to take ahead of the costs of CCS becoming clear, and the technologies being fully developed.

A further option would be the creation of a feed-in tariff which would guarantee a higher price for electricity from CCS power plants. This approach has been used successfully in other countries (eg to support the deployment of photovoltaic systems in Germany) – but once again would seem a difficult approach to take ahead of knowing the costs of CCS.

The common factor in the above three approaches – EU ETS, regulatory compulsion, or feed-in tariffs – is that the costs of CCS would be passed to consumers.

In some cases it may be possible to off-set some or all of the costs of CCS through using carbon dioxide to enhance the recovery of oil from depleted reservoirs (Enhanced Oil Recovery – or EOR). This is technically feasible and is being used commercially in some US oil fields - but the economics of EOR remain unproved in UK waters and further study into its commercial feasibility is required. Given current oil prices it can be expected that oil companies will wish to examine this opportunity.

The Scottish Centre for Carbon Storage is currently undertaking a joint study into CCS and EOR opportunities in Scotland - involving Scottish universities, power companies, oil companies, and the Scottish Government.

Given that the costs of CCS remain uncertain – and that these costs may be met through the EU ETS in any case – no additional costs for delivering CCS have been factored into this paper's view of future electricity prices.

EU Emissions Trading Scheme

The Stern Review[17] stated that "establishing a carbon price, through tax, trading or regulation, is an essential foundation for climate-change policy". The EU Emissions Trading Scheme (EU ETS) is the EU's primary mechanism for creating a market value in the reduction of carbon emissions, and will act to embed the cost of carbon emissions in the goods and services that we all consume. It is therefore designed to act most strongly on those sectors which emit the most carbon, or consume the greatest amount of energy. As the sector which is the single largest carbon emitter, and for its capacity to pass through the costs of regulatory measures to consumers, the power generation sector has been deliberately targeted by the European Commission and the UK government more strongly than other sectors.

Under the EU ETS sectors are allocated allowances for the carbon emissions they are expected to emit. If an organisation wishes to emit more than its allowance then it can buy additional allowances on an EU wide market. If an organisation has surplus allowances it can sell these. The total amount of allowances allocated across the EU is subject to an absolute cap. In the UK the electricity industry will progressively be allocated fewer carbon allowances and required to buy the extra allowances it requires in auctions.

In 2012 Phase III of the EU ETS will come into force. In the March 2008 budget the Chancellor announced that the UK would implement 100% auctioning of carbon allowances for the electricity industry. Under this system large electricity producers will be obliged to buy all the carbon allowances they require. Given the relative insulation of the power sector from external competition we can expect the full cost of these allowances to be passed on to consumers as the sector seeks to maintain profit margins.

A range of estimates exist for the cost impact of the EU ETS. The European Commission's own assessment of the impact of the EU Emissions Trading Scheme estimates that a carbon price of €22 per tonne will result in an increase in retail electricity prices of between 19% and 26% by 2020 (the level of increase depending on the size of the consumer).[18] The paper goes on to argue that the price impact of EU ETS may already be partially priced into current European retail electricity prices – and that the actual price impact of Phase II could therefore be lower - in the range of 10% to 15%. The UK Energy White Paper (May 2007) stated that "assuming an EU ETS carbon price in 2020 of around €15-25t/CO2, the impact on retail electricity prices could be a 14-23% increase for industrial, and a 10-15% increase for household consumers, compared to if there were no carbon price." However it is worth noting that since the White Paper's publication sterling has slipped by around 18% against the euro (the currency in which EU ETS carbon allowances are priced). Using more recent exchange rates would give an estimated increase of 12% to 18% for household electricity prices from the EU ETS.

The above increases may seem relatively modest. However, there are forecasts that the price of carbon could be significantly higher than the scenarios given above. In June 2008 Deutsche Bank revised its estimates of 2020 carbon prices upwards from €35 to €40 per t/CO2.[19] A price which would (with 100% auctioning for the power sector, and at current exchange rates) suggest a 43% increase in UK electricity prices for industrial energy users, and a 29% increase in domestic energy prices.

Energy efficiency

Energy efficiency measures are often one of the quickest and most effective means of reducing energy consumption – and therefore carbon emissions. Under the Energy Efficiency Commitment (EEC) energy suppliers are required to add a small percentage to consumer energy bills – and reuse the funds gained in activities that reduce household carbon emissions. Under this scheme energy companies have, for example, distributed cheap or free energy efficient light bulbs to many homes. The UK Energy White Paper proposes expanding this scheme to cover a wider range of technologies and activities to encourage behavioural change. The Energy White Paper estimates that the measures proposed will add 1.5% to 2% to household energy bills. Increased energy prices will also act as a spur for increased investment by consumers in energy efficiency. The White Paper believes that over time the increase in electricity bills due to energy efficiency measures will be outweighed by reduced energy consumption – and therefore consumer energy bills could benefit from a net reduction. However other studies suggest that the benefits from improved energy efficiency will be offset to some extent by households using money saved to consume additional goods and services – known as the rebound effect (though any rebound effect would seem likely to be weaker if energy prices are also increasing in parallel).

Nuclear power

The UK Government appears committed to the development of a new generation of nuclear power stations in the UK – and has stated that this development will be constructed and funded in full by the commercial sector. The commercial sector will then recover these costs through consumer electricity bills. The Scottish Government is opposed to the development of new nuclear power stations in Scotland – but given that there is a GB electricity market it appears likely that the costs of developing nuclear power will be spread across all GB consumers.

The UK Energy White Paper, and the associated consultation documents[20], assert that the costs of nuclear power are comparable to other forms of conventional generation (and therefore implies that the cost to consumers will be no higher than the development of fossil-fuelled generation). Other analyses[21] assert that attempts to estimate the total cost of nuclear power are unlikely to be accurate – and that the construction of nuclear power plants is subject to a number of significant risks that are likely to increase costs. The calculation of the full costs of decommissioning and waste management is also difficult – as government policy and regulatory requirements may change over time. The UK Government is apparently committed to commercial operators meeting the full cost of decommissioning and waste management, and to operators recovering these costs in full during the operation of new nuclear power stations.[22] However the UK Government has also committed to offering operators a fixed price for decommissioning and waste disposal[23] - albeit with a margin for risk built in. This appears to show that both UK Government and the energy industry believe there is a risk of cost escalation – and should the actual costs exceed the fixed price agreed then the gap will be met by the taxpayer. This effectively represents a public subsidy to the construction and operation of new nuclear power stations.

Given the uncertainty over the costs and timescales for the construction of new nuclear power stations (it is for example by no means clear that any new nuclear power stations will have been built by 2020) this paper has not factored in any additional costs for nuclear power in its estimates of future electricity prices.

Conclusions

The drive for cleaner, lower carbon electricity is likely to be with us for decades to come as Scotland, the UK, and the EU work to meet ambitious climate change targets. This will require investment in new cleaner electricity generation, grid infrastructure and carbon storage systems. This investment drive will not come without significant cost and current mechanisms will pass these costs on to the consumers of energy – homes and businesses. In the UK the main additional regulatory costs will come through the EU Emissions Trading Scheme and the Renewables Obligation. In addition energy companies may seek to increase prices in order achieve a commercial rate of return on sizable investments in new energy infrastructure. As global energy demand continues to rise there are also likely to be additional price increases in the underlying costs of primary fuels (oil, gas, coal, uranium) – and these will create significant additional increases in the price of electricity. Higher energy costs will also be transmitted by businesses into increased consumer prices for goods and services – and these will be particularly significant for those goods and materials that embody a large amount of energy in their manufacture (such as steel, concrete, some chemicals, paper, and some parts of the food and drink sector).

Adding together the various measures detailed above suggests that without any underlying increase in primary energy prices by 2020 clean energy support and regulatory mechanisms can be expected to add at least 23% to household electricity prices and 30% to industrial electricity prices (primarily using the figures in the Energy White Paper), and if Deutsche Bank is right about the future costs of carbon allowances under the EU ETS the increase in electricity prices will be in the region of 42% for household energy users and 60% for industrial energy users.

The UK Energy White Paper suggests that price increases will lie at the lower end of the above estimates, and that cost increases will in any case be offset very largely by improved energy efficiency. It argues that improved energy efficiency will lead to an overall reduction in energy consumption (and therefore act to reduce energy bills). But given our continuing propensity to increase consumption energy efficiency seems unlikely to deliver stable energy bills on its own. Capturing the benefits of improved energy efficiency in homes and appliances will also depend on achieving widespread and long-term behavioural change. In addition, if energy price increases due to regulatory action lie at the upper end of the above range it is clear that energy efficiency measures (using the Energy White Paper's figures) would not be sufficient to those offset price increases.

There remains a question as to how to consumer demand for electricity would respond to long-term and significantly increased prices. Classic economic theory suggests that as price increases consumption should drop. However a wide range of studies[24] show that elasticity of consumer demand for electricity is relatively low – that is, demand neither increases dramatically when electricity prices are low, or reduces significantly when electricity prices increase (a 10% rise in electricity prices is estimated as resulting in a 2.1% fall in domestic demand in the short-run and a fall in demand of 1.8% in the long-run – providing incomes do not also rise in real terms). Other sectors are more sensitive to prices rises – for the commercial and industrial sector electricity a 10% rise in all fuel prices is reckoned to result in a 3.3% fall in demand in the short-run and a 2.9% fall in the long-run. As stated earlier, electricity prices have increased significantly over the last 4 years. In 2006 industrial electricity consumption dropped by 2% (the first time consumption had dropped for 5 years), but demand in the domestic sector remained steady.[25] The low response of domestic demand to increases in prices could be because people consume the services that electricity enables (eg light, television, cups of tea, clean clothes) – rather than consuming the product itself – and that people are highly resistant to changing their behaviours in these areas.

The final question is whether the response of electricity suppliers and generators to the various policy instruments detailed above is likely to have any additional impact on electricity prices. The primary objective of the EU ETS is to reduce carbon emissions by altering producer behaviour (but not necessarily the power generation sector). By trading emissions the theory of the EU ETS is that those sectors which can abate emissions more cheaply (or more quickly) will do so. The nature of investment in electricity generation (where the infrastructure has very long timescales), and the lack of competition in the market (which means generators can pass costs through to consumers), probably means that the electricity sector will be slow to respond. Some analysts speculate that the main impact of the EU ETS out to 2020 will be to push generators away from coal and towards gas-fired generation (as gas is a less carbon intensive fuel). Fundamentally this decision depends on the producers' view of the future price of gas relative to coal once EU ETS is factored in (and their view of their ability to pass costs through). Gas prices are indexed to oil prices, and therefore are currently high.

Classic economic theory might also suggest that a reduction in consumer demand for electricity might led to producers reducing prices (in order to gain market share). However given that there is limited competition in the electricity sector producers might instead seek to maintain levels of return on investments by increasing electricity prices.

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