THE BOTTOMLESS PIT

The Economics of Carbon Capture and Storage

Gordon Hughes

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Foreword

By Dr Benny Peiser

The idea of carbon capture and storage (CCS), capturing carbon dioxide and storing it permanently so that it will never be released into the atmosphere, has been around for nearly 40 years. Carbon dioxide capture technology has been used in practice since the 1920s. But over the last two decades, enthusiasts for the technology have promoted the idea of applying CCS on an extraordinary scale. Since most international energy agencies agree that fossil fuels will remain the dominant form of energy consumption in the next three to four decades, they claim that only the global deployment of CCS will allow nations to continue to use cheap oil, gas and coal. Without this mega-project, they warn, it will be all but impossible to prevent a global warming disaster.

Both the International Energy Agency and the Intergovernmental Panel on Climate Change have highlighted the crucial role CCS technologies will have to play if the international community wants to meet the emissions pledges set out in the Paris Agreement. Yet in spite of these warnings, and the strong support of world leaders and many climate scientists, OECD governments have been stepping back from funding large-scale CCS projects, thereby slowing the pace of development. As a result, few CCS projects are in the works, and many more have been cancelled, not least by President Obama and the British government. What is more, the hundreds of billions that are being spent on renewable energy have significantly worsened the prospects of the technology ever being applied on anything like the utopian scale that is being advocated.

This new GWPF report, written by one of the world's leading energy economists, explains the reasons for the manifest failure of CCS to progress and illustrates the economic and technological limits of a technology that has been promoted for too long on the basis of wishful thinking.

About the author

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Key messages

1. Carbon capture and storage (CCS) is a group of technologies that has promised much but, as yet, delivered little. The vision was a low-carbon world in which abundant reserves of fossil fuels could be burned without contributing to the accumulation of greenhouse gases in the atmosphere. Reality turns out to be very different. Part of the reason is that the costs involved in building and operating carbon capture units have not come down by as much or as rapidly as was initially expected. But even if costs had come down by more, there have been fundamental changes in the structure of electricity markets and institutions which mean that the role of CCS, if there is one at all, is likely to be very different from the original vision.
2. Most of the R&D that has been devoted to CCS has focused on baseload coal plants which are expected to operate for 85–90% of hours in the year. The high costs of building carbon capture projects would be spread over 7500 hours a year for 30+ years. However, the demand for such plants was tied to the dominance of large, vertically integrated, electricity utilities that were able to pass their costs through to customers. Such utilities have largely disappeared from the electricity systems of rich countries and are declining in middle-income countries. Even where they continue, nuclear and gas plants are preferred since they offer lower costs and greater operational flexibility. Few, if any, independent power producers would contemplate building anything other than gas plants under current or prospective future market conditions.
3. The exception is renewables – wind and solar – because of the subsidies that are available. However, the money that has been spent on promoting renewables has greatly worsened the prospects for CCS. The primary sources of renewables are intermittent but have low marginal costs, so they displace gas or coal generation when available. Periods when renewable generation is low must be covered by generating plant that can respond quickly and operate economically at load factors of less than 50%. Coal plants with CCS cannot meet this requirement.
4. In the developing world, the economic future of CCS depends on two critical questions:
    - To what extent will China and India choose to invest in nuclear power to meet their needs for baseload generation over the same period?
    - What will the average ratio between gas and coal prices on a heat equivalent basis be over the next 20–30 years?

    The answers to both questions seem likely to turn out badly for CCS. China is investing heavily in nuclear power for baseload generation and India seems to be moving in the same direction. As a consequence, existing and new coal plant will operate at average load factors of 55–65% rather than 85–90%, which increases the average cost per tonne of CO_2 (tCO_2) abated by 40% or more. If, at the same time, the price of gas is only 2–3 times the price of coal, then it is cheaper to replace coal plants with gas plants rather than to fit CCS to new plants or retrofit CCS to existing plants.

5. Who should bear the costs of development and learning required to commercialise CCS is a separate and open question. Analyses of the costs of carbon capture rely heavily on what are called *N*th-of-a-kind (NOAK) estimates, i.e. after a reduction in costs due to economies of scale and learning. However, these NOAK costs grossly underestimate the likely costs of carbon capture over the next 20–30 years. Many cost projections assume learning rates – the reduction in costs for each doubling in cumulative installed capacity – far in excess of actual experience with similar technologies. Even if the learning rate was as high as is assumed, a cumulative investment of $500–600 billion in coal power plants with carbon capture and $300 billion in gas plants with carbon capture would be required to bring costs down to the NOAK levels reported. There is little likelihood that OECD countries will be willing to commit the funds required. Equally, it is unclear that China would be willing to underwrite the learning costs when it has made a major commitment to nuclear power.
6. Even when costs have fallen to NOAK levels – sometime after 2040 – the average cost of reducing CO_2 emissions by fitting CCS to coal or gas plants will be at least $120 per tCO_2 for baseload plants and may be $160–200 per tCO_2 at plants operating with load factors of 60% or even 50% for gas plants. The marginal costs of reducing CO_2 emissions would be much higher because the least-cost strategy would involve replacing coal with gas and only then installing CCS. These values are much higher than estimates of the social cost of carbon (SCC) for developed and developing countries up to 2050. A review of the SCC suggests that the upper limits on the amounts that countries should be willing to pay for reducing CO_2 emissions are $100 per tCO_2 for developed countries and $50 per tCO_2 for China, India and other large developing countries.
7. Rather than focusing on how to reduce emissions at a single plant, analysts should examine the marginal cost of reducing current and future CO_2 emissions for a national electricity system. Such marginal costs depend upon decisions about grid and dispatch management, demand growth, locational decisions, and future investment levels. For example, for China, investment in the transmission grid to permit wind generation in the west to be managed jointly with hydro plants in the rest of the country is a far cheaper way of reducing CO_2 emissions in the next 10–15 years than retrofitting existing coal plants with CCS or building new coal plants with CCS. As a side effect, such investment will reduce

the expected load factor for coal plants and thus push up the unit cost of capturing CO_2.

8. New coal plants will continue to be built in developing countries where locational factors are favourable. The development of gas pipeline and electricity transmission networks will gradually erode these locational advantages and encourage the spread of gas generation. But when new coal plants are built they will not be fitted with CCS, nor are they likely to be retrofitted with CCS at any time in the future.

9. For developed countries with low or no growth in electricity demand – the US and Europe – the cheapest way of reducing power-sector CO_2 emissions on a significant scale is to move coal plants – initially subcritical units but also supercritical units – down the merit order, replacing their output with combined cycle gas turbines (CCGTs) at higher load factors. Next cheapest is to decommission coal altogether, using new, high-efficiency, single cycle gas turbines as peaking capacity. In a few countries, geothermal, biomass or energy from waste units may yield CO_2 reductions at low cost, but only when these use resources that are not currently exploited.

10. Once existing coal generation has been replaced by gas, the marginal abatement cost (MAC) of making further reductions in CO_2 emissions rises steeply. For example, adding renewable generation – wind and/or solar – displaces gas generation with relatively low CO_2 emissions per MWh and decreases system-wide fuel efficiency by increasing the costs of ramping up/down, reactive power and frequency control. Conventional (Generation III/III+) nuclear power plants will reduce system-wide CO_2 emissions at lower cost than renewables (except in the most favourable locations) where nuclear power is permitted, provided that designs and safety features are standardised.

11. The marginal abatement cost for reducing CO_2 emissions using a combination of renewables – wind in some places, solar in others – backed up by hydro (best) or gas can be low or moderate under the most favourable conditions. Only the more expensive forms of renewable generation – such as solar and offshore wind in north-west Europe – have a higher marginal abatement cost than retrofitting CCS to existing coal plants. At the same time, the development of intermittent renewables has undermined the viability of investment in anything other than the cheapest forms of baseload generation.

12. The analysis shows that if carbon capture has any future it will be for gas plants operating with load factors in the range 40–60%. This type of application has not received significant research interest because sponsors and academics have focused too much on the use of carbon capture for baseload coal plants. As a

consequence, experience with the design and application of the technology is limited and costs are highly uncertain.

13. Alternative combustion cycles may offer a better way of reducing CO_2 emissions. In the last three years there has been considerable publicity attached to a pilot project in Texas based on the Allam Cycle, which uses supercritical CO_2 in a gas turbine. It has a claimed lower heating value efficiency for gas of nearly 59% with carbon capture of 97%. If the pilot is successful and can be scaled up, this might transform the prospects for CCS for both gas and coal (via coal gasification).
14. Finally, the UK faces a pressing issue. Over the next eight years there is a need to build or rehabilitate up to 40 GW of gas capacity to backup intermittent renewables, replace coal and gas plant that will be retired, and to meet new environmental standards. Current market conditions will not sustain anything like this level of investment, so it will depend upon the availability of and conditions on capacity contracts. The technology of carbon capture for gas plants is far from mature. Even so, it has been argued that a system target of $0.05tCO_2$/MWh should be set for 2030. This cannot be achieved without CCS being installed at most gas plants.
15. If the power industry expects that carbon capture must be fitted to new gas plants and/or retrofitted to existing gas plants before 2040, capacity bids up to 2025 will be based on recovering all of the capital costs over a period of 10–15 years. This will add up to £9 billion a year to the fixed costs of operating the electricity system up to 2030. In addition, the average spot market price of electricity would have to rise by £10–15 per MWh to compensate for the increase in the heat rate (GJ input per MWh of output) at the marginal gas plants which set market prices. That increase would add £3.5–5 billion to electricity bills. In combination with existing commitments, the overall level of support for low-CO_2 generation in 2025 would be equivalent to 150% of the cost of the UK's electricity consumption at the average spot market price in 2016. Is the UK government seriously prepared to place this burden on industrial users and household consumers?

1 Introduction

This paper examines whether and in what circumstances the commercial deployment of CCS is likely to be economic in the period up to 2050. The crucial test that is applied is whether the marginal abatement cost (MAC) of CO_2 reductions achieved by deployment of CCS is likely to be less than \$100 per tCO_2. This is more stringent than the usual approach adopted by studies of CCS, which focus on the average cost of CO_2 reductions. In economic terms, the average cost is irrelevant. This is because it is possible to make rapid and substantial reductions in CO_2 emissions at a zero or low cost by using gas rather than coal in power generation and similar applications. Further, it is necessary to examine the costs of CCS in the context of electricity or energy systems overall rather than restricting comparisons to specific applications – usually baseload power generation.

2 Setting the scene

Debate in the UK and Europe about the best strategy to reduce CO_2 emissions from the power sector has tended to focus on the respective roles of renewable energy (principally wind and/or solar power) and nuclear power. This perspective reflects local concerns rather than the importance of these options at a global level. It is reinforced by the incoherence of EU policies, which set separate targets for CO_2 emissions and renewable energy output, even though the latter could only be justified by reference to the former.

Stepping outside the confines of the European market, it is clear that the central challenge thrown up by any serious analysis of paths to a low-carbon future for the world in 2050 or 2100 is how to use fossil fuels without the associated emissions of greenhouse gases. There are different ways of presenting this reality, but in terms of political economy the key considerations may be summarised by focusing on the interests of five countries at the top of the ranking of national emissions of greenhouse gases: China, the USA, India, Russia and Indonesia. These countries accounted for about 50% of global emissions in 2011. China alone represented 22% of global emissions.[1] Two considerations stand out:

- Two out of the three largest country sources of CO_2 are developing countries with large reserves of coal, limited gas resources and economic goals that imply a large increase in energy and electricity consumption in future. It is easy for interest groups within these countries to portray attempts to arrest and even reverse the prospective growth in CO_2 emissions as a not-so-subtle strategy to suppress the legitimate ambitions of countries who were the victims of colonial oppression.

- All of the top five emitters have large reserves of fossil fuels that can be extracted at a low cost. There is no indication that any of them is willing to forego the resource rents that can be earned by extracting and selling fossil fuels. Even when national or local policies restrict the use of fossil fuels in the domestic power sector, no attempt has been made to discourage producers from exporting their output. As a consequence, the primary impact of domestic policies is to shift consumption across national boundaries with some reduction in the resource rents that accrue. It is, of course, easy for countries that have (largely) exhausted their reserves of fossil fuels to argue that reserves elsewhere should not be extracted, but even European countries have shown little willingness to follow the logic of their position, as it affects their own reserves of fossil fuels.

One simple approach is to place greater reliance upon price signals. This need not involve emission trading schemes, which tend to become complex and burdened with all kinds of special provisions that lead to unintended consequences. In the power sector, regulatory or other caps on the cost per tonne of pollutant that can be passed through to customers will provide strong and transparent incentives for generators to adopt low-cost options for controlling emissions. Going further, a carbon tax or minimum floor price would provide similar incentives and even greater transparency.

The difficulty, as any reference to a carbon tax illustrates, is that transparency and efficiency are rarely central considerations in developing policies to reduce carbon emissions. Unfortunately, experience teaches us that politicians and government departments tend to be liberal in their use of taxpayers' money when faced with concerted lobbying by industrial interests whose cooperation is imagined to be or is actually necessary for the attainment of some policy objective. Environmental campaigners are easily seduced by grand visions and want to believe the most optimistic claims about current or future technology. On the other side, attempts to inject a degree of realism into the assessment of technological and policy options are portrayed as obstruction prompted by dubious motives and a failure to understand the larger picture (whatever that might be).

One lesson from the history of international environmental agreements is that moral suasion has a very limited role in promoting action, whereas money and technology can be crucial. The availability of relatively cheap alternatives to CFCs and methods of reducing SO_2 emissions were critical elements in the adoption and implementation of the Montreal Protocol (on ozone-depleting substances) and the various sulphur protocols. It is not necessary that the alternatives or controls should be widely used. What matters is access to some kind of backstop technology at a reasonable cost. This can be used to convince participants that they will not face the prospect of large and uncertain costs to meet the goals that they sign up to.

Together these considerations suggest that carbon capture is a backstop technology that would give key countries the confidence that substantial and real reductions in CO_2 emissions, beyond those attainable through better energy efficiency and low cost controls, can be achieved without large economic penalties. However, it can only play this role if its capital and operating costs are not too high and the prospect of commercial deployment is not too distant.

3 Carbon capture technologies

From an economic perspective, carbon capture has strong similarities with flue gas desulphurisation (FGD) for the removal of sulphur dioxide (SO_2) from the emissions from coal-fired power plants. It is an exercise in chemical engineering which adds substantially to the capital cost of building a new coal-fired or gas-fired plant, reduces the net output of the plant and requires a considerable amount of space. Retrofitting existing plants may therefore be difficult, expensive or simply impossible. Still, over 30 years the costs of FGD units has fallen as the equipment has been standardised and generators have learned how to operate them more efficiently.

Various lessons from the development of FGDs will be discussed below, but there was one particularly contentious issue that is relevant to carbon capture. This concerned the minimum level of sulphur removal specified in domestic environmental standards and international agreements covering Europe. Under the initial Sulphur Protocol, countries were bound by commitments to reduce emissions of SO_2 in 1995 by at least 30% relative to 1980. Under the Second Sulphur Protocol these targets were tightened, with reductions of up to 83% required by 2000. However, in implementing the original agreement the EU – pressed by Germany – introduced legislation requiring that all coal-fired power plants had to install equipment to remove at least 85% or 90% of SO_2 emissions, with various deadlines. In practice, this legislation mandated the installation of FGD units for new and some existing power plants, while doing little to encourage older plants to reduce their emissions.

The debate, involving economists, industrial interests and environmental lobbyists, was prompted by the option of using alternative technologies – notably limestone injection and pressurised fluidised bed boilers – which could reduce SO_2 emissions at a significantly lower cost per tonne[2] of SO_2 than FGD installations but which were not able to meet the requirement for 90% removal. Economists argued that by combining the use of low sulphur coal with these alternative technologies, national targets could be met at a much lower cost than through installation of FGD units. The opposing view was that the technology standards offered certainty, protected countries and power operators that had opted for FGDs, and would stimulate cost reductions in the design, construction and operation of FGDs. The same claims could, of course, have been made for any other technology.

Carbon capture is more difficult and expensive than the removal of SO_2 or nitrogen oxides (NOx) because CO_2 is a much less reactive gas. If this were not the case, we would not be worrying about the accumulation of CO_2 in the atmosphere on a global scale. In contrast, both SO_2 and NOx are rapidly converted to sulphates and nitrates by a variety of reactions in the atmosphere, and this takes place within a relatively short distance of where they were emitted. The reason for concern about SO_2 and NOx is that the sulphates and nitrates formed by these atmospheric reactions are acidic and make up a substantial share of fine particles, which are the most important source of health damage associated with air pollution.

Controls designed to remove SO_2 and NOx from exhaust gases mimic the natural processes before the gases are emitted. Indeed, there is an irony that the standard type of FGD technology uses limestone (calcium carbonate) to capture SO_2, producing gypsum (calcium sulphate) and CO_2. While FGDs can hardly be blamed for the increase in atmospheric CO_2, the widespread adoption of FGDs to solve one environmental problem has increased emissions of greenhouse gases. As is often the case in environmental policy, the lesson is that it is very hard to find measures that target one pollutant and have no side effects.

The EU has specified that technologies eligible for support should remove 90% of CO_2 from exhaust gas. This pushes the choice of capture technology in the direction of solutions that are highly capital-intensive and have high energy consumption. Even then it is not clear that they are capable of meeting this target in practice, as the current demonstration projects can only achieve much lower capture rates of 65% or less. Moreover, it is hard to remove 90% of the CO_2 from exhaust streams that have relatively low concentrations of CO_2, for example those from gas combined cycle plants. At an early stage in the technology cycle for carbon capture, it seems ill-advised and certainly uneconomic to set such a stringent standard rather than focusing on the cost per tonne of CO_2 (tCO_2) captured.

Carbon capture involves the removal of CO_2 from exhaust gases produced by the combustion of carbon-based fuels. I will focus primarily on what is referred to as 'post-combustion' carbon capture as this is compatible with existing technologies for using fossil fuels to generate electricity and for other industrial purposes. Alternatives such as oxy-fuel combustion capture or pre-combustion capture involve a much more radical modification of combustion and generation technologies, so they are unsuitable for retrofitting existing or future conventional power plants. As a consequence, they do not offer any route to reducing emissions from the existing capital stock. The alternative would be simply to scrap the existing power stations, and since this is unlikely to happen sufficiently quickly to alter the embedded path of emissions, a cost-effective implementation of post-combustion carbon capture is essential to achieve the targets that have been set for the next 30–40 years.

In addition, pre-combustion carbon capture – using either integrated gasification or other methods – is a less mature technology than post-combustion capture. Most estimates suggest that the costs for commercial deployment will not be significantly lower than those for post-combustion capture. Further, integrated gasification is a notoriously difficult technology to operate reliably at a high level of performance. These factors mean that pre-combustion carbon capture is unlikely to be deployed on a large scale in major coal-using countries like China, India and Indonesia before 2050, if at all.

On current evidence, there is little doubt that post-combustion capture can be made to work, even on a large scale. The technology has been used as an industrial process in specialised applications for more than two decades, almost all of them in circumstances where the captured CO_2 can be used for enhanced oil recovery in nearby oil fields.[3] The issue is one of cost rather than technical feasibility. The main option for post-combustion carbon capture in the medium term is amine scrubbing, a technology that can cope with flue gas concentrations of 3–15% CO_2, typical of power plants. The choice of an amine solution involves balancing the capture rate against the energy required to regenerate the solvent; that is, separating the CO_2 from the amine after capture. In addition, the solvents are usually sensitive to impurities in the flue gases, so that SO_2, NOx and particles must be removed before or during the carbon capture stage. This means that carbon capture is an addition to existing environmental controls, which have not been installed at all power plants, and notably not at Chinese ones.

Alternative approaches are being developed to process flue gases from wet FGD units. These designs are claimed to be significantly less expensive than amine scrubbing, because the energy costs of regeneration are lower. Other designs are being optimised for use with flue gas from gas plants, which has a much lower concentration of CO_2 (typically 3%) and a higher concentration of oxygen than that from coal plants. Many of these technologies are operating only as demonstration projects, so the results have yet to be tested at an operational scale.

Amine scrubbing has been used at scales of up to 4000 tCO_2 per day, but this would have to double for a single 500 MW coal plant. There are many coal plants around the world with capacities of 2000–3000 MW, so the technology needs to work at a scale 10 times that of the largest of current operations. Whether this is possible remains to be seen. The alternative would be to install separate amine scrubbers to process the exhaust gases from each unit at a power plant. This would reduce economies of scales and would not be feasible in the normal situation, where FGDs have been constructed to serve multiple power generation units.

Storage, usually understood as involving the injection of CO_2 into depleted oil and gas fields, may or may not be part of the package. Many countries have little or no storage capacity of this kind. Even in those countries which do have suitable storage sites, there may be considerable opposition to permanent underground storage onshore, though this is routine for natural gas. Hence, other options for carbon sequestration may be required.

4 CCS markets

National markets

Before examining the economics of CCS it is crucial to identify the nature of the electricity systems and markets in which it may be applied. This may be done by considering a small number of target markets – the UK, Germany, the USA and China – which have different characteristics and requirements.

The UK The UK has an uncomfortable mixture of a deregulated power market, historically strong incentives for renewable generation, and an increasing level of central intervention to address the lack of investment in new dispatchable generating capacity. For a considerable period, policy was based on what turned out to be a mistaken assumption of high and rising gas prices. Demand for electricity has fallen significantly over the last eight years and there has been strong growth in wind generation. Together, these trends have led to a decline in wholesale electricity prices. There has also been an increase in price volatility because of fluctuations in the level of renewable generation. Faced with more stringent environmental regulations, several coal plants have shut down or been converted to biomass. The government has sought to promote nuclear as the main source of future baseload generation, with a combination of wind and gas generation meeting daily or seasonal variations in demand. However, it has become clear that investors are unwilling to commit to sufficient investment in gas generation under the current market regime, so payments for backup capacity are likely to determine the number and type of new gas plants that will be built. There is little prospect that new coal capacity will be added to the system in the next decade, or that existing coal capacity will be refurbished. As a consequence, any application of CCS in the UK will be for gas plants operating with load factors of 65% or less – in many cases no more than 30–40%.

Germany The UK and Germany are different in three critical respects. First, the German government has committed to the phase-out of nuclear power by the early 2020s, so baseload coal plants seem to have a future. As a result, large generators are investing in the construction of new coal plants including integrated gasification combined cycle (IGCC) units. Second, the incentives for investment in renewable generation capacity have been even larger than in the UK, with the result that the wholesale electricity price has been even more volatile. Many gas plants cannot cover their operating and maintenance costs and have been either mothballed or decommissioned, while older coal plants are being operated to offset fluctuations in renewable output. Third, the large German generators are more vertically integrated than their counterparts in the UK and may be better placed to pass on the costs of investments in CCS. However, most of them face dire financial prospects because of the cost of the nuclear phase-out and losses on gas generation. CCS may therefore be adopted for baseload coal plants, but only if German electricity consumers are willing to bear the costs on top of the costs of phasing out nuclear power. Whether they will is far from clear, as German consumer prices for electricity are already among the highest in Europe.

USA The primary market drivers in the USA have been the impact of the shale revolution on gas prices and the stimulus for renewable generation provided by tax incentives and renewable obligations.[4] The USA has huge production and reserves of low-cost coal. Even so, at anything close to current gas prices, efficient CCGT units have a decisive advantage in terms of cost and flexibility for utilities operating in competitive power markets. A number of vertically-integrated utilities operating under rate-of-return regulation may choose to build new coal plants, but this trend is outweighed by closures of old plants and/or conversions to gas. The median coal plant (by capacity) is more than 40 years old and less than 5% of coal generating capacity was built in the last 20 years. Existing coal plants will be retired if they are required to retrofit CCS, while the number of new baseload coal plants for which CCS might be relevant will be very small. In the US, the role of CCS will be almost entirely about its application to gas CCGT units. The average load factor for US CCGTs was 56% in 2015, but it was below 50% for 9 out of the 10 years from 2005 to 2014.

China China is, by far, the largest coal producer and consumer in the world. The amount of coal generating capacity has grown massively in the last decade, but this increase has not been matched by the increase in coal production. The use of coal outside the power sector is likely to fall as it is displaced by gas, particularly in urban areas with poor air quality. Nonetheless, the growth of baseload coal generation is likely to be constrained by the availability of coal supplies. It is clear that the Chinese government views nuclear power as an important source of baseload power in future. As in other countries, the transition to Generation III+ (EPR and AP1000) reactors has been beset by delays and cost overruns. The government has promoted the adoption of a small number of Generation III/III+ designs to obtain economies of scale and learning in construction and operation. Retrofitting CCS to coal plants built over the last decade may be an important opportunity in future, but only if the costs of carbon capture are much lower than currently seems likely. Such plants will not operate on baseload, so that the technology needs to be optimised for coal plants with load factors of about 60%.

Sectors

Potential applications of CCS include industrial activities, such as the production of iron and steel, cement and a variety of bulk chemicals. It is also used in oil and gas production and specialised chemical processes to separate CO_2 that may be associated with the product or which is produced as a by-product of manufacturing. CO_2

injection is one of the standard techniques of enhanced oil (or gas) recovery and is used increasingly widely in Canada and the USA. The characteristic of all such applications is that CCS is deployed as part of a high value-added production process, so that relatively high costs of capture, transport and/or storage can be covered by the value of the output.

The test for the deployment of CCS in the power sector, which is critical for reducing future emissions of CO_2, is that its costs must be accepted by consumers who rely upon plentiful supplies of electricity at relatively low prices. Low-carbon strategies that rely upon widespread replacement of petroleum-fuelled vehicles with electric vehicles ratchet up the importance of CCS in the power sector, since the only realistic low-carbon alternative on a global basis is nuclear power. If the economics of CCS are attractive enough to underpin its use in the power sector, then there is little doubt that it can – and will - be deployed in other industries.

CCS is a generic term covering a range of technologies which are or may be suitable for a range of applications. Most of the economic analyses of CCS have focused on the application of CCS to large coal plants operated as baseload generators in OECD countries, and many studies focus on the levelised cost of electricity (LCOE) from such plants, with or without CCS. This framework of analysis may have been appropriate for electricity systems in the second half of the 20th century but it is almost completely irrelevant to market conditions in 2020 and beyond (see Appendix A).

In summary, the primary application of CCS is not likely to be baseload coal plants, whether new builds or retrofits. Instead there are two quite distinct likely applications. These are:

- gas CCGTs in OECD countries, operating at load factors of less than 60% and often less than 40%, with a requirement to respond quickly to changes in demand; that is, with short ramp up and ramp down periods
- retrofits to coal power plants, many of them in China, operating at load factors of 55–65%; these will have economic lives of only 20–25 years, much shorter than the standard assumption of 40 years for new plants.

Neither application matches the standard calculation of the LCOE for baseload coal plants with and without CCS. The cost per MWh to recover the capital cost of carbon capture units will be much higher than for baseload plants, while the parasitic consumption – the proportion of the plant's output required to power the CCS unit – will be significantly increased by a requirement to match the level of generation to fluctuations in demand.

There is another reason why most 'economic' analyses of CCS are irrelevant. No-one doubts that the quickest and cheapest way of reducing CO_2 emissions today and for next two decades is to replace coal-fired power generation by gas-fired generation. That is what underpins the reduction in US emissions of CO_2 over the last five years. Hence, the correct test is to ask how much it would cost to reduce CO_2 emission beyond those achievable from a modern CCGT operating at a thermal efficiency of 58+%. In other words, the fundamental economic issue is not to identify the average cost of reducing CO_2 emissions by deploying CCS. Instead, we must focus on *the marginal cost of going beyond what we can already do at minimal cost*. Constructing the marginal cost curve for CO_2 removal is very difficult because of jumps in technology and system-wide effects that are difficult to capture in the models used (see Appendix B).

5 Costing CCS

A key problem that faces the development of CCS projects is the sheer scale of the capital investment that is required. Even a modest 500 MW coal power plant operating on baseload will produce about 3.2 million tonnes of CO_2 per year. This may be compared with the liquified natural gas (LNG) facilities in Qatar, the largest in the world, which have the capacity to produce 77 million tonnes of LNG per year or the equivalent of 12 GW of coal generating plant. China added an average of about 37 GW of coal plant per year over the period from 2010 to 2013. In physical terms, fitting 37 GW of new coal plant with CCS each year would imply a construction program that would be 30 times the scale of the construction program required to build Qatar's LNG facilities. The annual investment required for carbon capture, pipelines and storage would be $200–300 billion per year.

The implementation of CCS for most fossil fuel generating capacity is therefore the equivalent of many large infrastructure projects. The record of executing such projects is poor in most countries. Consistently, they cost much more than expected at the time of approval and they take longer to build. This is not a uniquely British phenomenon. The examples of Berlin Airport or the 'Big Dig' in Boston or the World Cup facilities in Brazil demonstrate that things can go badly wrong in countries with ample experience of designing and building large infrastructure. The most serious lesson of all comes from the huge cost overruns for the fourth generation nuclear power plants constructed by Areva in Finland and France. While it may be unduly cautious, the best advice may be to take the initial estimate of the capital cost, double it and perhaps double it again.

In this paper, I will focus on the economics of CCS in power generation, but with one important difference from the mainstream. There is a strong tendency to think in terms of the use of CCS to reduce emissions from individual power plants, usually coal-fired plants. This approach is understandable when addressing the need to retrofit existing plants, but it will not lead to an efficient strategy for reducing CO_2 emissions at a national or global level. The reason is that an electricity supply industry is a system, not just a collection of individual generating stations. Simply adding notionally cleaner technologies does not necessarily produce a cleaner system at an affordable cost.

As noted above, the default low cost way of reducing CO_2 emissions from an electricity system is to build gas plants, thus allowing coal plants to be retired or moved down in the merit order for dispatch. Such an approach will incur a lower cost per tonne of CO_2 saved than building nuclear plants or promoting renewable energy or, even, adopting costly energy-efficiency measures. Viewed from the perspective of an electricity system rather than that of the individual power plant, it is essential to consider the economic costs and benefits of applying CCS to gas plants. There may be a role for coal plants with CCS, but their costs must be compatible with the cost curves for reducing CO_2 emissions as defined by gas.

This is the central contribution of economics to the debate about how to reduce emissions of greenhouse gases. Public agencies and academic institutions tend to think in terms of technologies. They concentrate on specific technical problems that are thought to contribute to a larger policy goal. The result is often the development and use of solutions that turn out to be absurdly expensive when a full assessment is undertaken. Notwithstanding the virtues of electric vehicles or solar panels or wind turbines on their own, they cannot form the core of a serious strategy to reduce global CO_2 emissions if the marginal cost, including any system-wide effects, exceeds some upper limit on the value per tonne of CO_2 (tCO_2) saved. For reasons discussed in Appendix C, I have used a value of \$100 per tCO_2[5] as an indicative value of what this upper limit might be for developed countries and \$50 per tCO_2 for low- and middle-income countries. So the ultimate question addressed in this paper is a simple one: does CCS offer the prospect of reducing CO_2 emissions from the power sector at a system cost that is less than \$50 or \$100 per tCO_2 at 2015 prices? If not, then there is little chance that it will be deployed on a large scale in the next 30–40 years.

6 Economies of scale and learning rates

The costs associated with some early projects have been extremely high. See for example the Boundary Dam and Kemper County projects discussed in Appendix D. These costs would be expected to gradually fall, as operators learn how to install and operate CCS units and as economies of scale are reaped: this is the lesson of experience:

- The classic story is how the costs of producing a standard Boeing 707 at a factory in Seattle fell steadily for 20 years after the aircraft was first introduced. The rate of production increased somewhat, but the real benefit came from the application of learning about how to carry out the process of manufacturing planes more efficiently.
- In the energy sector, the cost of producing photovoltaic (PV) modules has fallen very substantially over 20 years. Much of the decline has been due to an in-

crease in scale, which will almost always reduce costs in processes relying on silicon fabrication, combined with the transfer of most production to low cost manufacturing centres in China and elsewhere in Asia. Those gains are one-off and they are limited to the components used for PV installations. It is reasonable to expect that technical innovation and manufacturing improvements will continue to reduce the unit cost of PV components, but such gains will have only a limited effect on the overall cost of solar installations as the cost of components declines relative to the cost of structures, civil works, and so on.

All analysts therefore accept that pilot projects and the first full-scale applications of a new technology will have higher unit costs than those expected when initial mistakes have been ironed out and routine processes of construction and operation have been established. Analysts refer to 'first of a kind' (FOAK) and '*N*th-of-a-kind' (NOAK) costs. However, even if the projected NOAK costs were to suggest a new technology was viable, the cumulative investment required to go from FOAK to NOAK might be so high that nobody could finance it.

The NOAK cost level for CCS and the speed at which it is reached therefore become critical values in determining the viability of CCS. However, it is important to recognise that these two parameters are no more than guesses, perhaps based on past experience but possibly only reflecting the optimism of the technology's proponents. Low projected costs and a fast learning process to get there are the basis of the 'infant industry' argument, which has been deployed by interest groups seeking 'temporary' subsidies many times over the last three centuries, ever since governments came to believe that they had some responsibility for promoting economic development.

Conditions that encourage rapid learning

To get a sense of the resources to deploy CCS on a large scale we have to start by considering how quickly costs are likely to decline as experience is accumulated. The rate of learning for power generation technologies is usually expressed in terms of the decline in average cost per MW for each doubling in installed generation capacity. A conventional assumption adopted by proponents of CCS is that average cost will decline by 20% for each such doubling of installed capacity. This translates to an assumption that average costs will decline by 52% as installed capacity increases from 1 GW to 10 GW and by 77% when cumulative capacity reaches 100 GW. It is claimed that such learning rates are justified by the experience of wind turbines and solar PV modules.

However, PV and wind are not likely to be good guides to learning rates. There are many factors that explain the difference, but they can be broadly classified under two headings: the role of scale and the nature of the technology.

Economies of scale Both solar PV and wind turbines have benefited from standardisation and manufacture on a scale that is between 100 and 1000 times that expected for carbon capture. Single PV modules or wind turbines are – and have long been – a tiny share of the total market. Whether it was 500 kW turbines in the past or 3 MW turbines today, the total market size amounts to thousands or tens of thousands of units per year. In contrast, the number of carbon capture units that will be commissioned over the next 20 years is unlikely to exceed 200 in total – an average of 10 per year. During that period most of the new units are likely to be one-off designs, no doubt with some standardisation of components, but without the scale economies offered by a high degree of project standardisation. This is precisely what has undermined opportunities for learning in building nuclear plants.

The nature of the technology An additional factor is that the average size of a solar PV module or a wind turbine has increased as the technology has developed, bringing economies of scale at the unit level. The manufacturing cost per MW of capacity of a 3 MW turbine today is significantly lower than that of a 1.3 MW turbine manufactured 10 or 15 years ago. The same tendency was seen in the past as the average size of boilers and generators for coal plants increased. However, there are limits on how far this process of increasing the scale of major components can go, because the risks and consequences of component failure outweigh the benefits of scale. Both manufacturers and generators prefer to rely upon the flexibility and reliability of installing multiple 300 MW gas turbines rather than a single 900 MW unit. In the case of wind turbines there are clear reasons why the benefits of additional scale – say, moving from 3 MW to 10 MW turbines – may not outweigh the potential problems in wind farm design, construction and reliability, particularly for onshore developments. Similarly, very large solar PV modules are difficult to manufacture and to deploy. In contrast, commercial carbon capture units need to be designed to match the scale of the power plants on which they will be installed. This scale is unlikely to increase rapidly in future and there will be limited economies of scale at the component level contributing to movement down the learning curve.

In most sectors, learning rates are lower and decline over time

However, learning rates have been much lower for many other generation technologies and, indeed, have been negative for nuclear power – even before recent safety concerns. All power generation involves a combination of civil engineering and machinery or equipment for energy conversion. For the most part, technical progress and cost reductions in civil engineering are steady and relatively slow by comparison with similar learning for specialised equipment and machinery. The consequence is that the civil engineering share of total project costs tends to increase over time, thus reducing the overall rate of cost reduction due to learning. This is very clear in the case of solar PV and wind generation. The reduction in the cost of PV modules has meant that their share of new project costs has fallen from greater than 50% to 20% or less. Even if module prices continue to fall at 20% per year the impact on the cost per MW will be limited and will continue to decline. The same consideration applies to wind farms: the cost of the turbines as a share of total costs has been falling, although it is still much higher than for solar PV projects.

The lesson of another power generation technology – gas turbines and combined cycle plants – reinforces the point. Initially, the turbines, steam recovery units, and so on represented a high proportion of the costs of a CCGT plant, so the benefits of learning led to a significant decline in total costs. However, in the longer run the learning rate has been only 5–10% per year rather than the much higher rates that have characterised solar PV and wind generation up to now.

Carbon capture is largely an application of chemical engineering technologies. The share of structures and civil works in the total cost of a unit is large, and there is no major component whose cost might be expected to fall rapidly. The experience of other technologies is therefore much more relevant than either solar PV or wind generation:

LNG The lesson from LNG is that high demand offsets the gains from the learning curve. After more than 20 years of development, the benchmark cost of LNG facilities is \$1000–1200[6] per tonne per year of capacity for a new greenfield plant.[7,8] Despite – or, perhaps, because of - the huge growth in LNG capacity over two decades the unit cost of LNG capacity has remained constant or even increased in real terms. Claims about learning curves and cost reductions in this part of the industry have not been borne out by experience. The upward pressures on costs due to high levels of demand have outweighed the benefits of learning.

Nuclear For nuclear power plants learning rates seem to have been negative. Standardisation and the manufacture of components at scale reduced the unit costs of pressurized water reactors designed and built by Framatome/Areva and Westinghouse. On the other hand, the transition from Generation II to Generation III/III+ reactors has led to large and apparently unforeseen increases in costs and delays in construction, even in China. This is sometimes blamed on the imposition of more stringent safety requirements after finalisation of the design, but it seems unlikely that this is the whole story, especially in China.

Coal, gas, hydro and FGD For coal, gas and hydro generation the empirical evidence suggests that learning rates do not generally exceed 10%. For FGD units installed between 1976 and 1995 the learning rate was about 15%, associated with an increase in cumulative installed capacity from approximately 6 GW to 85 GW.

Overall, it is reasonable to assume that the learning rate for carbon capture plants will fall in the range of 5–15%.

Getting to NOAK costs for CCS will take time and be expensive

Overall, the assumption of high learning rates which underpins published estimates of NOAK costs for carbon capture seems to be a variant on the more general phenomenon of appraisal optimism, which muddies attempts to make reliable estimates of the costs and performance of large infrastructure projects or programmes, especially when at a relatively early stage of policy formulation. Attempts to allow for appraisal optimism are rarely successful because the knowledge that preliminary costs may or will be adjusted creates a vicious circle that undermines the credibility of any costing exercise.

There are different ways of calibrating the learning curves for coal-fired plants. Using the Global CCS Institute's database of large projects, excluding natural gas processing, the cumulative installation of carbon capture up to the end of 2016 is equivalent to about 2.5 GW of coal-fired power generation. It is reasonable to assume that learning processes for pre-combustion and post-combustion carbon capture are quite separate, since they are quite different technologies.

Post-combustion capture The cumulative installed capacity at the end of 2016 is equivalent to 1 GW, while the cost reduction required to get down to the assumed NOAK costs is of the order of 60%. With a learning rate of 15% this would involve the cumulative installation of about 60 GW of capacity at a cost of about $500 billion in post-combustion projects alone.

Pre-combustion capture The Kemper County project is the largest and most recent such project and has a capital cost of about $12,800 per kW. To get down to NOAK costs with a learning rate of 15% would require the cumulative installation of 120 GW of capacity and a total investment of at least $600 billion.

If the learning rate is only 5% the unit costs will, for practical purposes, never get down to NOAK levels, for either pre- or post-combustion technologies. Even under the most optimistic assumptions of joint learning for pre- and post-combustion carbon capture plus a learning rate of 20%, a cumulative investment of at least $500 billion will be required on a global scale to realise the learning required.

Whichever way the figures are presented and analysed, it stretches the imagination to believe that the investment required to get down to NOAK costs for carbon capture will be forthcoming, especially since it would be quite reasonable to assume lower rates of learning. Even if one country or a group of countries were willing to invest on the scale required, there are practical issues in executing the necessary investment program. Building a coal power plant takes at least four years, including design. To gain the benefit of learning from previous phases of the development program new construction phases must be staggered with at least four-year intervals. If the first phase of construction were to start in 2020 and each phase were double the size of the previous one – both rather optimistic assumptions – cumulative construction of coal plants with carbon capture would only exceed 60 GW in 2044 and 120 GW in 2048. Commercial deployment of coal generation with CCS would not be possible for at least 30 years, while slower rates of learning or subsidised construction would delay commercialisation until after 2050.

Based on reported costs for the Mongstad and Peterhead pilot projects – see Appendix 15 – the costs of carbon capture at gas plants have to fall by at least 67% to reach NOAK levels. With a learning rate of 15% this would require a cumulative installation of 100 GW of capacity, at a cost of about $300 billion. The construction time for gas plants should be only three years, so an investment program started in the mid-2020s would achieve commercial deployment in the late 2040s, similar to the end-point for coal plants. Overall, the development of carbon capture for gas plants seems likely to be less expensive and time-consuming than for coal plants, but in neither case will the technology achieve commercial levels of cost much before 2050. Even these timetables rely upon learning rates at the top end of relevant experience in the power sector.

Few private utilities or contractors have the financial resources to absorb the scale of cost overruns that may be involved in moving from FOAK to NOAK costs. Areva has effectively gone bankrupt as a result of the unanticipated costs of building the first two units of its new generation of nuclear plants – the EPR. Cost overruns at nuclear plants have been a financial disaster for several US utilities and, more recently, for Toshiba through its subsidiaries Westinghouse and Stone & Webster. Similarly, the scale of the cost overrun for the Kemper County CCS project would have undermined the financial strength of most utilities and has had a significant impact on the balance sheet of its owner, the Southern Company, which is the third largest US electricity utility. There are only ten electricity utilities in the US with a market value in excess of $20 billion, the size at which taking on the risks of early-stage carbon capture plants could be contemplated.

This means that most of the investment required to move from FOAK to NOAK costs for carbon capture will have to be financed and/or underwritten by state funds and guarantees. However, there is little prospect that either governments or public authorities in Europe and the US are willing to do this on the scale required. China is the only country with the flow of projects and level of resources that would offer the prospect of progress towards NOAK cost levels for coal-fired power plants in the next 30 years. For gas-fired power plants the US would almost certainly have to take the lead, but this seems very unlikely to happen within the next decade.

In summary, the average cost of building new carbon capture units can reasonably be expected to fall as a consequence of a combination of learning and economies of scale. However, the experience of solar PV and wind generation provide a rather poor guide to the rate at which costs are likely to fall. Based upon the experience of directly comparable technologies, CCS costs may be expected to fall by between

5% and 15% for each doubling in cumulative installed capacity. Under the most optimistic assumptions, average costs for carbon capture at both coal and gas plants may fall to NOAK levels by the late 2040s. To reach this point in the learning curve will require a cumulative investment of at least $500 million (at 2015 prices) for coal plants and at least $300 million for gas plants. It is far from clear that any country or group of countries is prepared to make the level of commitment required before 2050.

7 CCS costs in gas and coal plants

The costs of carbon capture for coal plants

There are many academic, official and other publications which offer estimates of the costs of installing carbon capture on new or rehabilitated power plants, some of them presenting figures to an accuracy of $1 per kW of capacity. However, only three carbon capture units have been built or are under construction at power plants operating on a commercial scale (see Appendix D). One of these – Boundary Dam in Canada – has been operating for two years and its performance is well below the original specification. The two other projects commenced operations in 2016, so reliable data on their operating experience will not be available until 2018 or 2019. The planned CO_2 capture rates for all three plants are well below the levels assumed in desk studies, so the problem of achieving a goal of 90% capture remains unresolved.

With that warning, I will rely upon the review of NOAK CCS costs published by Rubin et al in 2015.[9] These estimates imply that a new supercritical coal plant with a net capacity of 800 MW (close to the average for new plants in China) would cost $2.2 billion without carbon capture and $3.85 billion with carbon capture (see Appendix E). The cost of *retrofitting* an existing coal plant of this size would be at least $2 billion and could be as high as $2.5 billion if scrubbers and other environmental controls were required. For a plant operating with a load factor of 60% – the average load factor for Chinese coal plants in 2015 was less 50% – the NOAK cost of adding carbon capture to a new supercritical plant would be $90–100 per tCO_2 reduction in emissions. Retrofitting an existing plant would push the cost up to $120–140 per tCO_2 depending on plant's age and thermal efficiency.

The costs of carbon capture for gas plants

The gap between academic estimates of the cost of carbon capture and future market requirements is even worse for gas plants in the UK, Europe and the US. At the moment it is likely that most gas plants will operate as a combination of backup to wind/solar generation and to meet peak load demand. Rather than receiving a steady flow of flue gas from a baseload coal plant, a carbon capture unit for a gas plant would have to be designed for an average load factor that will be less than 50% – and perhaps much lower – with a requirement for short warm-up and cool-down periods to permit intermittent operations matching the pattern of demand. There is little evidence that researchers developing the technology are close to solving the specific problems that arise in fitting carbon capture to gas turbines designed for this type of use.[10]

A key difference between applying carbon capture to gas plants rather than coal plants is the much lower concentration of CO_2 in the exhaust gases. The typical concentration is 14% for coal plants but may be as low as 3% for gas plants. In a coal CCS unit, even with 85% removal of CO_2, the exit concentration of CO_2 is only a quarter lower than the input, so capture units for gas plants must be longer. Moreover, the higher concentration of oxygen in the flue gases may lead to increased loss of solvent due to oxidative degradation.

One way of dealing with these issues is to burn a mixture of gas, oxygen and CO_2 (known as oxy-combustion) to drive a CO_2 turbine using the Allam cycle.[11,12] The exhaust gas from the Allam cycle consists of CO_2 and water, so the CO_2 can be recycled within the system or exported for storage. However, the cost of the first demonstration plant – a 25 MWe unit – is quoted as \$140 million, more than twice the equivalent cost of a gas CCGT fitted with carbon capture.[13] It is possible that the advantages of higher net efficiency or greater flexibility of Allam cycle turbines may outweigh their higher capital cost. Equally, demonstration projects of this kind have a tendency to exceed their original budgets – often by a large margin – so the real prospects for oxy-combustion technologies can only be assessed when commercial scale plants have been built and are operating.

The representative cost of adding a carbon capture unit to a gas CCGT is estimated by Rubin et al to be about \$1,000 per kW of capacity, about the same as the base cost of a CCGT without carbon capture. This assumes a load factor of 85%, nearly double the average value for US gas plants. The representative capture rate is 88%, which reduces the expected emissions per MWh from 0.36 to 0.04 tCO_2. The parasitic consumption of a carbon capture unit is expected to be 14% of gross output. The recurrent costs of operating the carbon capture unit would be about \$6 per MWh for a gas CCGT operating with a load factor of 50%.

Why gas makes better sense than coal

These estimates shed an interesting light on the economics of retrofitting coal plants with carbon capture. Consider a mid-life coal plant with a current capacity of 1000 MW which emits 0.8 tCO_2 per MWh of gross electricity output. The capital cost of installing a carbon capture unit at the plant will be approximately \$2 billion and the net capacity of the coal plant will fall to about 770 MW. As an alternative, the generator could build a gas CCGT including a carbon capture unit with a gross capacity of 900 MW and a net capacity of 770 MW. The capital cost would be about $1.7 billion, about 15% less than the carbon capture unit for the coal plant on its own. Emissions at the retrofitted coal plant would fall to about 0.104 tCO_2 per net MWh, whereas they would be about 0.047 tCO_2 per net MWh at the gas plant. Operating and maintenance costs at a new gas plant would be significantly lower than for the existing coal plant; the saving would be equivalent to about $13 per net MWh, which would go some way to offsetting the higher fuel cost of the gas plant. The difference in the capital cost of construction is equivalent to $6 per net MWh over 20 years using a low discount rate of 5%.

With these differences in costs between retrofitting a coal plant and building a new gas plant there is a simple trade-off between coal and gas based on heat rates, fuel prices and load factor (see Appendix F). The Rubin et al. study uses a reference price of $2.74 per GJ for coal (on an HHV[14] basis). On a straight plant-for-plant comparison it would be cheaper to opt for a new gas plant if the expected gas price is less than $6.15 per GJ or $6.45 per million Btu. The US market price of gas has been well below this level since the beginning of 2009. In addition to lower costs, the gas option implies significantly lower emissions of CO_2 and greater flexibility in operating the plant over a range of load factors. The advantage in favour of gas is much larger when the alternative is a new coal plant with carbon capture, whether supercritical coal or IGCC. At the reference price for coal, the market price for gas would have to be greater than $12 per GJ to warrant consideration of a new coal plant. European gas prices exceeded this level briefly in 2013 but are now well below it and are likely to remain so for as long as US gas prices remain so low.

The implication of this assessment is that carbon capture will be limited to gas plants in all but a few countries around the world: those where coal is very cheap relative to gas. Regulations, such as those in California, which require coal plants to be fitted or retrofitted with carbon capture are little more than a disguised way of banning the use of coal in power generation. The same could be said of the UK government's commitment to ban all unabated coal power stations.[15]

Even for China, the spot market price for LNG deliveries is currently well below $6 per million Btu and there is a large amount of under-utilised regasification capacity in operation or due for completion before 2020. Thus, it will be cheaper to reduce CO_2 emissions from power plants in the provinces along the east coast by building new gas plants than by building new coal plants or retrofitting existing plans. Plans for imports of gas from Russia by pipeline will reinforce the advantage of gas in northern China.

This advantage of gas over coal is likely to be replicated in coastal areas of India. The spot price of natural gas in the industrial states on the west coast has been consistently below $4 per million Btu, largely because the transport cost for LNG supplies from the Gulf is well below the transport cost for supplies to north Asia. In contrast, transport costs for coal imported from Indonesia, South Africa or Australia are relatively higher. The Indian government has declared a goal of eliminating thermal coal imports and replacing them with gas, which will reinforce the probability that any application of carbon capture in India will focus on gas rather than coal plants.

8 The costs of CO_2 transport and storage

The transport of CO_2 by pipeline is a mature technology that is not subject to substantial uncertainty about costs. Thousands of kilometres of CO_2 pipelines have been in operation for a decade and there would be no great difficulty in modifying natural gas pipelines for the same purpose. This is particularly relevant if storage in depleted gas fields is contemplated. Information on alternative methods of transport, e.g. the transport of liquefied CO_2 by ship, is more speculative but the comparison with natural gas with respect to the costs of LNG chains provides a starting point.

There are large economies of scale for all kinds of pipeline transport. Controlling for variations in location and terrain, Rubin et al. report that the average cost per tCO_2 per 250 km for pipeline designed to handle 3 million tCO_2 per year – equivalent to one 500 MWh coal plant – is roughly three times the average cost of a pipeline designed to handle 30 million tCO_2. Thus, there would be large benefits from designing a CO_2 collection and transmission system that gathers the CO_2 produced at many power and industrial plants and transports it in bulk to the final point of storage. Transport considerations of this kind will favour reliance upon large-scale storage.

As an illustrative calculation using the mid-points of the estimates reported by Rubin et al., the cost of transporting CO_2 from a power plant over distances of 150 km using an onshore collection pipeline and 500 km offshore using a bulk transmission pipeline would amount to \$8 per tCO_2 transported. Clearly, the structure of costs will favour plants that are located close to the main transmission pipelines and/or to potential storage sites.

The main option for CO_2 storage, especially in the UK, is the reuse of depleted offshore oil and gas fields – geologic storage. An alternative is the use of underground salt caverns, but this has provoked strong resistance when proposed for managed onshore storage of natural gas. It seems likely that objections to the creation of permanent onshore storage facilities for CO_2 will be even stronger, especially if offshore storage seems to be convenient and relatively inexpensive.

CO_2 is already used on a significant scale for enhanced recovery of oil or coal bed methane in locations where the geology and resources are suitable. When oil and gas prices are high enough, this can generate a credit that will more than offset the costs of capture and transport. However, this is a specialised application, and it does not affect the economics of CCS as a policy for reducing CO_2 emissions on a large scale.

Inevitably, the costs of geologic storage of CO_2 are strongly affected by site conditions: the storage capacity, the ease of capping the storage, and the costs of monitoring and insuring future liabilities. The fundamental issue is one of attitudes to risk. If CCS were seen as the only realistic option for reducing CO_2 emissions at a reasonable cost while maintaining current levels of income and consumption, the public might accept a different trade-off between risk and cost than in circumstances where it is argued that alternative strategies could be adopted.

According to Rubin et al., with current regulations and approaches to risk management, estimates of the cost of offshore geologic storage span a range from \$4 to \$24 per tCO_2 at 2015 prices. Using the mid-point, the combined cost of CO_2 transport and storage would be about \$34 per tCO_2 of reduction in emissions from a coal plant and about \$27 per tCO_2 for a gas plant.[16] These estimates are small relative to the costs of carbon capture, which explains the focus on the cost of capture rather than storage in deciding whether to adopt CCS on a large scale.

9 Summary so far

Before turning to a discussion of how CCS fits into the spectrum of policies that might be adopted to reduce CO_2 emissions, it will be helpful to summarise the main conclusions from this review of technology, NOAK costs and experience:

- Researchers have focused on supercritical coal plants operating on baseload, which will have only a small share of future power generation; most investment in new coal plants will be for mid merit units, with lower load factors, and much funding will be for nuclear.
- In many countries building new gas capacity is cheaper than retrofitting coal plants, while still giving substantial emissions reductions even without CCS being fitted. Even considering NOAK costs for retrofits of coal plants, it will probably be cheaper to switch from coal to gas with CCS.
- If intermittent renewable sources of generation provide a significant amount of power, then CCS needs to be economic for gas turbines and combined cycle plants operating at load factors of 40% or less.
- Moving from FOAK to NOAK costs for CCS is likely to take 25–30 years and will require extraordinary levels of investment.
- Transport and storage of CO_2 is relatively cheap, but may be politically difficult.

Finally, the proponents of CCS should put aside the hype and salesmanship. The field is dogged by exaggerated claims and a lack of realism in assessing market needs. A few projects that are delivered roughly on time and on budget will be much more convincing than endless fluff about the need for CCS and rosy claims about technological progress. In this respect, the Petra Nova project is the most convincing demonstration available, but unfortunately this seems to confirm that carbon capture at coal plants will be a niche solution and only justifiable as a component of enhanced oil recovery projects.

10 CCS costs and the social cost of carbon

The upper limit on the acceptable cost of CCS is the lower of:

- the marginal cost of deploying alternative strategies to reduce CO_2 emissions
- the marginal benefits to society that are expected to accrue from reducing the level of CO_2 in the atmosphere.

The second element is usually known as the social cost of carbon (SCC). The extensive (and often contentious) literature on the subject is summarised briefly in Appendix C.

Analyses of the SCC suggest that developed countries should be willing to pay up to \$50 per tCO_2 to deploy CCS,[17] but that anything more than \$100 is probably unreasonable – even in the decade 2040–50. For developing countries the threshold will be considerably lower because their economic circumstances and prospects imply that they should apply a significantly higher discount rate than developed countries. Thus for China and India the upper threshold on the cost of reducing CO_2 emissions by using CCS might be set at \$50 per tCO_2 up to 2050.

To put these thresholds in context, an analysis of abatement options in East Asia published in 2013[18] concluded that it would be possible to reduce business-as-usual (BAU) emissions levels for China in 2030 by about one-third at a MAC of less than \$50 per tCO_2-equivalent. Had the analysis been extended out to 2050 that reduction would have been even greater, because the marginal costs of abatement tend to fall as the time horizon increases. This is because there is greater flexibility in adapting the capital stock. The costs of reducing CO_2 emissions were higher for Japan and South Korea, but it was still thought possible to reduce BAU emissions in 2030 by between one third and one half at a MAC of less than \$100 per tCO_2-equivalent.

It is important to avoid spurious accuracy in carrying out analyses and presenting results based on complex models that cannot be reliably calibrated. The calculations that generate the SCC are a thought experiment; the exercise is useful as a way of ruling out policies and abatement options that are likely to be unreasonably expensive as ways of reducing greenhouse gas emissions. CCS will fall into that category if the MAC exceeds \$50–100 per tCO_2 depending upon the country and alternative control options that are available.

11 Identifying efficient ways of reducing CO_2 emissions

In assessing the potential role of CCS in reducing emissions from electricity generation it is critical to consider the abatement cost for the whole electricity system rather than for individual plants (see Appendix B). A useful tool is the MAC curve. The MAC curve shows how the additional cost of reducing emissions by, say, 1 $MtCO_2$ per year increases as the targeted level of emissions reduction increases. With this information it is possible to estimate the actual or implied carbon prices required to meet different CO_2 targets. MAC curves can easily be misused, especially when it is claimed that there are large opportunities for achieving emission reductions at a negative or zero cost without explaining why such options are not being adopted already or where they rely upon behavioural changes by millions of people. However, they are instructive when used to consider alternative ways of meeting specific scenarios within the power sector.

In developed countries

For countries without significant growth in electricity demand, as is the case in much of Europe, the cheapest way of reducing CO_2 emissions on a significant scale from the power sector is to move coal plants – initially subcritical units but also supercritical units – down the merit order, replacing them with CCGTs operating at higher load factors. The next cheapest option is to decommission coal altogether using new, high-efficiency, single cycle gas turbines as peaking capacity. In a few countries, geothermal, biomass or energy from waste units may yield CO_2 reductions at low cost but only when these use resources that are not currently exploited.

Once existing coal plants have been largely or wholly displaced by gas, the MAC for further reductions in CO_2 emissions rises steeply. For example, adding renewable generation – wind and/or solar – displaces gas generation with relatively low CO_2 emissions per MWh and decreases system-wide fuel efficiency by increasing the costs of ramping up and down, reactive power and frequency control. Where permitted, conventional (Generation III/III+) nuclear power plants will reduce system-wide CO_2 emissions at lower cost than renewables (except in the most favourable locations), provided that the designs and safety features are standardised.

Even with the most optimistic NOAK costs, the MAC for coal plants with CCS (either supercritical or IGCC) will be 30–40% higher than for nuclear plants once transport and storage costs are included. Up until 2040 the premium for coal with CCS over nuclear will be 60–80%. Even if the price of coal is effectively zero it is difficult to justify investment in new coal plants with CCS on economic grounds.

The MAC for new gas combined cycle units with CCS could be similar to that for nuclear plants even before 2040 provided that:

- the plants are guaranteed to run on baseload, and
- the price of gas is less than \$5 per GJ at 2015 prices.

At NOAK costs, the MAC for new gas plants with CCS will be less than or similar to those for nuclear plants if the price of gas is less than \$7 per GJ. This shows that the ranking of gas with CCS in the MAC curve for a national power system is very sensitive to the future price of gas that is used in the calculations.

The costs of retrofitting CCS to existing gas plants are very uncertain and sensitive to the load factor of the retrofitted plant. At NOAK prices the MAC for retrofitting CCS to an existing gas plant may be as low as \$120–140 per tCO_2 for gas prices in the range \$5–7 per GJ, but the average MAC will exceed \$150 per tCO_2 up to 2040. However, the choice will rarely be one of retrofitting CCS on its own, even assuming that there is sufficient land available. For gas plants that are older than 12–15 years, operators are likely to replace the gas and steam turbines and perhaps the heat recovery units in order to improve the thermal efficiency of the plant at the same time as installing carbon capture. This will increase the capital cost, though it would still be less than an entirely new plant, and would imply a MAC of over \$200 per tCO_2 if the plant were to continue to operate at a load factor of less than 50%.

In terms of competition between coal and gas, the price of gas has to be at least four times the price of coal on a heat equivalent basis for new coal plants with CCS to be economic at NOAK costs when compared with new gas plants with CCS. Using annual averages, this condition has been been met in north-west Europe only in one year in the last three decades – 2013 with a ratio of 4.02 – while the average ratio was 2.6.[19] At these prices there is very little prospect that new coal plants with CCS will be economic relative to new gas plants, with or without CCS.

The MAC for reducing CO_2 emissions using a combination of renewables – wind in some places, solar in others – backed up by hydro (best) or gas can be low or moderate under the most favourable conditions. Only the more expensive forms of renewable generation – solar and offshore wind in north-west Europe – have a higher MAC than retrofitting CCS to existing coal plants. At the same time, the development of intermittent renewables has undermined the viability of investment in anything other than the cheapest forms of baseload generation.

In developing countries

The level of generating capacity in large developing countries, such as China and India, is expected to grow rapidly for many years. Here the MAC curves are dominated by the costs of reducing carbon emissions from new plants. In many countries the ratio of peak-to-baseload demand for thermal generation will increase due to the increase in demand from households, light industry and services as well as an increase in the share of renewables. If new plants run on baseload, existing plants will be used as either mid-merit or peaking plants, and therefore with lower load factors. Provided that the new plants are more efficient than existing ones, this change will reduce the system average level of CO_2 emissions per MWh, although plant emissions per MWh may increase.

In the past, the potential role of gas in reducing CO_2 emissions in developing countries has been downplayed because it was assumed that LNG prices would be too high. This assumption is no longer warranted, especially for a country like India which is close to major gas exporters. Subject to local factors, such as liability issues concerning nuclear power in India, low-carbon development in Asia will rely heavily on nuclear power and gas CCGTs to provide a mixture of baseload and mid-merit generation. The high costs of CCS will rule out any substantial reliance on new coal with CCS and it is unlikely that carbon capture will be fitted to new gas plants, other than pilot projects, before 2040 or 2050.

In China there are huge variations in the costs of wind power across the country, which are exacerbated by transmission constraints. Provinces in the north and west of the country have average load factors for wind plants above 30%. A strategy of concentrating new development in locations with the best wind resources, upgrading the grid and using ample hydro resources to offset intermittency in wind generation will reduce emissions from old and relatively inefficient coal plants at an MAC of less than \$20 per tCO_2. Solar power, even in desert locations, is much less economic and relies upon heavy subsidies provided through feed-in tariffs.

The key trade-off for low-carbon development in China will be between imported gas (LNG and by pipeline from Russia) and domestic nuclear plants. Nuclear plants are regarded as being already competitive with new baseload coal plants fitted with scrubbers and other pollution controls. The combination of grid constraints and locational factors – most nuclear and gas plants are located in East Coast provinces – means that new coal plants will be developed in inland China over the next 15 years, but there is no prospect of new coal plants with CCS being viable anywhere before 2040 and probably not after that. The development of a denser gas pipeline network supplied by Russian gas will allow the displacement of coal by gas after 2025. The coastal price for LNG imports is less than \$8 per GJ while the cost of pipeline imports is likely to fall in the range \$8–10 per GJ. In both cases, new gas plants – even with CCS – will be cheaper than new coal plants with CCS.

The prospects for India are similar, with low-carbon generation relying upon a combination of nuclear power and gas. There are greater opportunities for the development of geothermal and biomass (using agricultural wastes), while solar is likely to be more important than wind. India's gas pipeline network is very limited – primarily serving the industrial west coast, with spurs to Delhi and to the east coast through

Hyderabad. Investment in new coal plants will therefore continue in areas without access to gas. However, in economic and environmental terms it will be much cheaper to import gas – either by pipeline or via LNG – to supply an expanded pipeline network than to invest in coal plants with CCS. The lack of a dense pipeline network and a reasonable number of partially or fully depleted oil and gas wells also mean that the costs of CO_2 transport and storage are likely to be prohibitively high.

It is frequently argued that the 'co-benefits' of reducing coal use will greatly reduce the MAC for CO_2 in countries like China and India. There is a kernel of truth in this argument, but it is usually applied in a manner that is either grossly misleading or simply wrong. The negative externalities of burning coal – damage to human health, crops and buildings – are largely associated with coal use outside the power sector. Even for the power sector, these externalities can be largely eliminated by installing scrubbers and other pollution controls at a cost that is far lower than CCS. All of the cost comparisons in this analysis assume that new plants without CCS include such controls, so that the co-benefits of adding carbon capture are effectively zero. The same applies to gas plants, though their negative externalities are much smaller.

12 The future of CCS in China

The potential role of CCS in China is critical. Without the prospect of application to the huge Chinese fleet of coal power plants there is no point in committing to the investment program that is required to move from FOAK to NOAK costs.

New coal plants will continue to be built in China in favourable locations, although the development of gas-pipeline and electricity-transmission networks will gradually erode these locational advantages and encourage the spread of both nuclear and gas generation. Under optimistic assumptions about learning rates and cost reductions, the total NOAK cost of CCS for new supercritical coal plants in China will be \$125–130 per tCO_2 avoided in 2050. During the learning period, over the next 30 years, the total cost of reducing emissions by deploying CCS at new coal plants will be 25–50% higher at \$160–200 per tCO_2 avoided. Building sufficient coal plants with CCS to move down the learning curve and so to meet these figures would require that China be willing to invest of the order of \$600 billion over three decades . These costs are 2–3 times the upper threshold of \$50 per tCO_2 reduction in emissions based on the social cost of carbon discussed in the previous section.

Only a small portion of the existing stock of coal plants in China is suitable for retrofitting with CCS and the costs of reducing CO_2 emissions through such retrofits will exceed \$150 per tCO_2 avoided, even after 2050. Unless the ratio of the price of gas to the price of coal is much higher than at present, it would be cheaper to invest the capital required for coal CCS retrofits in new gas plants fitted with CCS, which would offer a larger reduction in emissions and other operational advantages.

Retrofitting coal plants outside China is even less likely, so we may reasonably discount any prospect that CCS retrofits will play a significant role in abating global emissions of CO_2 in the next 30–50 years.

Even these figures offer too sanguine a view of the prospects for CCS on coal plants in China, because they focus on decisions concerning individual plants rather than planning for the electricity system as a whole. The United States Energy Information Agency (EIA) projects that China's generating capacity will increase by about 500 GW from 2020 to 2040. Allowing for retirements of existing coal plants, the gross investment in new generating capacity will be about 800 GW over 20 years. If the 54% share of coal in total capacity projected for 2020 were maintained, gross investment in new coal plants would be about 570 GW over two decades. Rather than build new coal plants with CCS over this period it may be much less expensive to reduce CO_2 emissions from the power system as a whole by substituting a mixture of nuclear and gas plants for coal plants. That, indeed, is exactly what the EIA expects to happen, with the consequence that the installed capacity of coal plants in 2040 should be lower in 2040 than in 2020. On their projections, gross investment in new coal plants will be only 260 GW from 2020 to 2040.

In almost all comparisons, Generation II+ (pressurised water reactor) or III nuclear plants have a cost of electricity that is at least 25% lower than NOAK costs of coal plants with CCS, when similar assumptions are made about load factors and cost of capital. In practice, coal plants are likely to have lower load factors, have higher CO_2 emissions and to be exposed to much greater uncertainty about fuel prices. The main limitation on the expansion of nuclear power is capacity to build plants, especially in inland provinces, away from the main concentration of existing and new plants in eastern provinces. For China, increasing the rate at which new nuclear plants are built is a significantly cheaper way of reducing CO_2 emissions than committing equivalent investment resources to moving down the learning curve for CCS at coal plants. The EIA's projections suggest that 110 GW of nuclear capacity will be built between 2020 and 2040. Sources within China suggest that the rate of new construction could be as much as double that.

It is always risky for economic forecasters to say 'never', but a forecast that there is no realistic prospect for large-scale deployment of CCS at new or existing coal plants in China during the next three decades seems as close to a sure thing as economic analysis offers. The primary qualification to this forecast concerns the future of nuclear power, which China is expecting to provide a great deal of its future baseload electricity, thus allowing it to reduce CO_2 emissions without relying upon CCS at coal plants. A nuclear accident or a large increase in the costs of building nuclear plants would slow up or halt the investment programme, but even under that scenario, relying more heavily on gas for baseload generation is likely to be economically more attractive than coal with CCS.

13 The future of CCS in the UK, Europe and the USA

It is important to be clear about the prospects for coal CCS in the UK, Europe and the USA. With current technology and costs, these are zero. It makes no economic sense to spend money on commercial-scale projects unless and until a new approach to carbon capture with much lower costs of construction and parasitic consumption has been developed. This is a harsh conclusion for the coal sector in the USA, which faces the prospect of rapid decline if the country sticks to its goals for reducing CO_2 emissions. However, the real threat to the coal sector is the use of gas for power generation, which is cheaper, has lower emissions and offers greater flexibility. The advantages of gas can only be offset if the prospective cost of coal CCS were about 25% of current estimates. This will require a different way of removing carbon from the exhaust streams of coal power plants.

Coal is gradually being displaced by gas in countries where markets play a significant role in determining both dispatch and new investment. Large utilities may retain some coal generation as insurance against a sharp rise in the price of gas. The size of this insurance requirement is likely to decline as gas markets become more integrated as a result of

- the growth in LNG trade, with large volumes coming from Australia and the USA
- a shift away from oil-indexed pricing for gas contracts.

In the OECD Europe countries, the EIA projections imply that gross investment in gas capacity from 2020 to 2040 will be about 250 GW, whereas gross investment in coal capacity will be only 75 GW. On top of this capacity displacement, coal plants will be operated at lower load factors, pushing up the penalty associated with CCS. The pattern in OECD Americas countries (the USA, Canada, Mexico and Chile) will be similar, with gross investment in gas capacity of about 490 GW versus coal capacity of 140 GW.

In 2015 the US Environmental Protection Agency published a new set of *New Source Performance Standards* for power plants. These would require new coal plants to install partial carbon capture, removing up to 25% of CO_2 for supercritical coal units. The equivalent standard for baseload gas-fired plants can be met by any modern CCGT operating at levels of thermal efficiency well below the current best practice. The regulation has been challenged in the courts but if it is applied it will reinforce the general switch from coal to gas in the US. As has been the case with other environmental regulations, it will extend the life of existing coal plants, discouraging their replacement by new plants.

While the EPA rule asserts that the costs of partial CCS are 'reasonable', it relies heavily on evidence from projects whose financing was based on a combination of public grants and the value of CO_2 for enhanced oil recovery. The implication of the arguments made by the EPA is that no new coal plants with partial or full CCS will be built in the US before 2030 unless they are supported by large subsidies or rely upon special market/utility conditions. The hiatus in construction will ensure that the US will not make any significant contribution before 2030 to the learning process required to achieve NOAK costs at which commercial deployment of CCS might be viable.

With the prospect of at least 750 GW of new gas capacity being installed in OECD Europe and Americas countries between 2020 and 2040, resources for R&D on carbon capture should be allocated almost entirely to developing efficient methods for gas turbines. From a system point of view this is clearly the right approach, as explained in Appendix B.

No doubt the case will be made that development of carbon capture for coal is an insurance against a large increase in the price of gas relative to coal. This would be a re-run of the justifications that were offered for the UK's energy policies from 2008 to 2014, which were based on the erroneous assumption that gas prices would be permanently higher in future. Though they are not directly linked, market prices for coal and gas are strongly correlated. The short-term volatility of coal prices is lower than that of gas prices but major upward or downward movements in energy prices tend to be reflected in both markets, though with different lags. Hence, the idea that there is a role for coal as a hedge against high gas prices ignores what we have learned from experience over the last 70 years.

There is another, less obvious, point that follows from the analysis. The MAC for reducing CO_2 emissions by installing CCS at gas plants is inversely related to the expected load factor; in other words, the higher the load factor the lower the MAC. The cost is high but might be judged to be acceptable for a baseload plant. As a plant moves away from baseload operation, the MAC for CCS increases to a level that is much higher than is likely to be acceptable. However, the impact of policies designed to promote renewables is that most new gas plants will operate at much lower load factors than baseload plant. This is particularly the case in the UK because the UK government has committed to using nuclear plants to meet a large proportion of future baseload demand. The consequence is that the only way to reconcile policies to promote both renewable generation and CCS for gas plants will be to incur very high MACs. It is yet another example of how governments have failed to think through the impact of renewable policies on their commitments to reduce CO_2 emissions at reasonable cost. The case of the UK is examined in detail in the next section.

14 The impact of gas CCS on the electricity market in the UK

The UK faces a particularly acute problem in deciding whether and when to require the use of CCS for gas plants. The reason is partly a matter of history and partly a consequence of policy choices made over the last decade. A large proportion of the UK's fleet of gas plants will reach the age at which they require rehabilitation within the next six years. However, these plants will be unable to meet the emission standards specified in the EU's Industrial Emissions Directive, which has been transposed into UK law and regulations. Their owners therefore have to choose between incurring large costs to upgrade the plants or to put them on a restricted operating schedule prior to closure before 2023.

Most of these plants do not operate on baseload and there is no prospect that they will do so in future. The commitment to nuclear power and wind generation means that these cover baseload demand of 20–25 GW from this or next year onwards, when there is adequate wind. Hence, carbon capture units installed on gas plants will have to be designed for plants that operate with a load factor of about 60%, with extended periods of minimal flow. In the UK these would occur at night and in the summer, but the patterns would be different in other countries. The capital cost would have to be spread over about 70% of the MWh of production that would be associated with baseload operation and would, therefore, be 40% or more higher per MWh.

The impact of renewables on wholesale electricity prices has been such that investors are unwilling to build new gas plants or to rehabilitate existing plants as pure merchant units: those that rely on revenues from the sale of electricity. Instead, investment will only occur if it is underwritten by capacity contracts to guarantee that investors can cover their capital and fixed operating costs. Allowing for the planned phase-out of coal-generating capacity by 2025, there will be a requirement for up to 40 GW in new or rehabilitated gas capacity over the next eight years. The expected load factor for this new capacity is likely to be less than 40%, meaning that the recovery of capital costs will be difficult under the best of conditions.

The question that follows is whether gas plants that are offered capacity contracts should be required to install carbon capture units. The choice is critical because it will determine the nature of the UK's generating sector until 2040 and beyond. One thing is certain. No private investors will build gas CCGTs with carbon capture under current market arrangements. The cost will fall directly or indirectly on electricity consumers and taxpayers via some combination of subsidies and levies and electricity prices. The impact on retail electricity prices will be 10–20 times the sums at stake in recent arguments about capping the energy prices charged by the large energy suppliers, yet the issue receives virtually no public or political attention.

The UK government is, in part, the victim of unfortunate timing, though the problems could have been foreseen 5–8 years ago. Carbon capture for gas plants is an experimental technology that is very unlikely to be ready for application at commercial plants before 2030. Because of the requirement for large replacement investment in gas plants before 2030, mandating the installation of carbon capture will involve large costs and the risk of serious delays – jeopardising the stability of the electricity system. Requiring only that new plants should be 'CCS-ready' implies that the electricity system will not be decarbonised before 2050 at the earliest, since the costs of retrofitting carbon capture at plants with a load factor of less than 50% would render them uneconomic. Any attempt to muddle through or adopt a halfway house will simply increase prospective costs and ensure that little or no investment is carried out.

Even if carbon capture were mandated for new gas plants, there is a critical barrier that is rarely recognised, let alone addressed. This lies in the way in which bidding and dispatch work in a competitive wholesale electricity market. In simple terms, the spot price for any period is determined by the variable cost – primarily fuel but including any variable operating and maintenance costs – of operating the most expensive plant required to match supply and demand. Wind, solar and nuclear plants have low variable costs and will always be dispatched when capable of operating. Under most conditions in the UK, the spot price is therefore determined by the gas price and the heat rate (gas consumption per MWh) of the marginal gas plant. Setting aside other interventions, if all plants have access to the spot market for gas, the dispatch order will be closely linked to the ranking of plants by heat rate. Plants with carbon capture will have higher heat rates than those without it because of the parasitic consumption of carbon capture units. So, in a system consisting of both types, plant with CCS will only be dispatched after all plant without it, thus ensuring low load factors and restricting their chances of recovering their capital costs.

The dispatch advantage of plants without carbon capture will be eliminated if the price of carbon is set at a level that offsets the benefit of a lower heat rate.[20] However, this introduces a large element of uncertainty into any investment decision. The expected utilisation of a new plant will depend entirely upon whether the future carbon price will be below or above the breakeven value, which will itself depend upon the future price of gas. In some markets this risk can be mitigated by hedging or by the expectation that prices will adjust to ensure that efficient operators can survive. Unfortunately, the carbon price has been – and is likely to remain – heavily influenced by government intervention, so hedging or other risk mitigation strategies will not be viable.

In response, investors are likely to require a very short payback period or, equivalently, to apply a high hurdle rate of return when deciding whether to build new plants. In addition to offering capacity contracts, the UK government would have to make a commitment to the level of the carbon (floor) price over the planning horizon for new plants, which would be at least until 2040. If this commitment were believed, which is far from certain, this would reduce risk and provide a basis for making investment decisions. However, there may be considerable resistance to adopting a policy that would tie the hands of future administrations and it would require a potentially uncomfortable public acknowledgement of the probable costs of reducing CO_2 emissions in future. The debate over the cost of the contract offered to EDF for Hinckley Point is likely to appear trivial by comparison with what would follow once the costs of support for the installation of CCS at new gas plants become apparent.

With a real cost of capital of 8%, the capacity contracts would cost nearly £120 million per year for each £1 billion of investment over a 15-year contract length. For 40 GW of gas capacity fitted with CCS this would represent a commitment of about £9 billion per year.[21] This sum would have to be met by electricity customers on top of existing commitments for renewable subsidies. In addition, the breakeven carbon price would add between £10 and £15 per MWh to the spot market price of electricity. This would apply to all electricity supplies, not just to the output from the new plants, and would add a total of £3.4–5.1 billion annually to electricity costs.[22] Combining the costs of support for renewables (at least £7–8 billion per year), nuclear generation (about £2.2 billion per year for Hinkley Point and Sizewell C), and CCS at gas plants (at least £12.5 billion per year) would imply an overall level of support for low CO_2 generation equivalent to 150% of the cost of the UK's electricity consumption at the average spot market price in 2016.

As a compromise, the government may be tempted to increase the carbon price above the dispatch breakeven level and offer less support for investment in gas plants with CCS. Suppose that the carbon floor price is increased from £18 per tCO_2 up to 2020 to £72 per tCO_2 by 2025 – a little below $100 per tCO_2 at the average exchange rate for 2016. Holding other factors constant, this would increase the expected spot price by £18–20 per MWh if the marginal units continue to be gas plants without CCS. Any gas plant with CCS that is built would expect to be dispatched as long as power demand exceeds the output from nuclear, hydro and renewable generators plus the contribution from the interconnectors. Allowing for the variability of wind output, a small number of gas plants with CCS should achieve an average load factor of 75–80%. At this level of utilisation, the increase in the expected spot price is not sufficient to recover the additional capital and operating costs of building a gas plant with CCS.

Allowing for CO_2 transport and storage costs, the increase in the expected spot price associated with a carbon price would need to be at least £30 per MWh to justify any major investment in gas plants with CCS. While the cost of capacity payments would be lower, the increase in the market cost of generation would be of the order of £10–11 billion per year, again in addition to support for renewables and nuclear generation. Further, the reduction in capacity payments would increase the risks that investors in new generation capacity were expected to bear and would almost certainly increase their cost of capital.

The situation in the UK is typical of that in most OECD countries. However, the overwhelming impression given by academic, commercial and public enthusiasts for CCS is of a lobby operating in a parallel universe. It is a world in which

- electricity systems are dominated by monolithic utilities with a primary focus on the latest generation of baseload plants

- there is a large demand for baseload power from industrial customers and the utilities are able to pass on the costs of such investments to consumers via rate hikes.

Vestiges of this world still exist in some southern states in the US, but most of it disappeared in the 1990s due to a combination of technical change (gas CCGTs) and deregulation. The impact of shale gas on the gas market over the last decade has reinforced this change in the structure of electricity systems. Mandates and subsidies for renewables have further complicated the situation.

No serious investor in power generation in countries with power markets and significant amounts of renewable energy worries about the levelised cost of electricity for baseload plant or any variant on it. That is just a route to bankruptcy. The harsh fact is that CCS has a very limited future in decentralised power markets in combination with renewable energy, which is where policy decisions have taken electricity systems. There are many reasons to regret the consequences of policy over the last decade but the embedded costs are already so high that the extra costs of the centralised intervention required for the adoption of CCS, even for gas, are unlikely to be accepted. The main impact of going down that route would be to accelerate the shift of manufacturing and other industries to countries that have less concern about reducing CO_2 emissions or are more willing to use nuclear power.

15 Recap and prospects

Recap

The story of carbon capture and storage can be viewed as a self-inflicted tragedy of energy and economic policy. The core justification for CCS has always been that, combined with more efficient supercritical or IGCC coal plants, it offered an inexpensive route to generating electricity with no or minimal CO_2 emissions, while making use of the large reserves of fossil fuels – particularly coal. That is simply not going to happen in the next 30–40 years, for reasons that are different in rich and middle- or low-income countries.

In rich countries the potential role of coal with CCS has been undermined by the huge level of support offered to renewable energy. This has imposed a heavy burden on consumers of electricity that they are increasingly unwilling to bear. Quite separately, it has become clear that electricity systems with high levels of intermittent wind or solar generation are alarmingly unstable, with large volatility in wholesale power prices. In such systems, coal plants – especially of the size for which CCS might be economic – cannot attract investment. Instead, grid stability and reduced price volatility requires investment in flexible gas plants – either CCGTs or high-efficiency turbines.

The circumstances of middle- or low-incomes countries with significant coal reserves are different. First, none of them has accepted any binding and substantial commitments to reduce CO_2 emissions under the UNFCCC. So they are likely to be much more concerned about the potential costs of adopting CCS and the risk of damage to their economic development. Second, few – if any – have the skills and technical capacity to implement CCS on a large scale. No doubt China and India could do this, but there is a reason why they prefer to stick with subcritical coal plants for much of their generation: they are cheap to build, easy to operate and relatively forgiving of poor operational management. The operational performance of even standard CCGTs in middle-income countries tends to be well below the frontier. This will be even more of a problem for supercritical or IGCC coal plants, which are difficult to run with even the best technical skills. Adding CCS will merely make the shortfall in performance even worse. For countries that have already made a large commitment to nuclear power – especially China and India – it will make much more sense to concentrate their efforts on bringing down the capital costs and improving the operational performance of their nuclear plants. The economies of scale and learning apparent in the French nuclear program will mean that an extension of nuclear generation will look to be much cheaper than an uncertain bet on sophisticated coal plants fitted with CCS.

The boat has already sailed for new coal plants fitted with CCS. There is no plausible economic future for this option. Of course, a number of countries will continue to invest in research and a few may even proceed to build the odd plant. This would be the consequence of over-optimistic expectations combined with the infinite capacity of governments to waste taxpayers' money.

Equally, the costs of retrofitting existing coal plants look prohibitive. Even if they adopt national programs to reduce CO_2 emissions, there are many alternatives for achieving this goal at a lower cost per tonne of CO_2. In China, for example, the switch from coal to gas for industrial energy use and domestic heating is both relatively cheap and has large associated benefits, namely reductions in air pollution.

We are therefore left with the potential role of CCS fitted to gas plants. Here, the overriding problem is one of scale and usage. On the positive side it seems that the parasitic consumption would be only 12–15%, over a fairly wide range of plant sizes, while the capital cost of adding carbon capture for relatively large plants (> 600 MW) would be about $1,000 per kW on an NOAK basis. The disadvantage is that plants of this size are not attractive to investors operating in markets in which the expected load factor for a new gas plant is only 50–60%.

In rich countries with strong incentives for non-dispatchable renewable energy, no one is building large gas plants and expecting them to operate on baseload. The only way in which new gas plants attract finance is when they are supported by extended term capacity contracts. In future, policymakers could require that such plants are fitted with carbon capture. This would be very expensive – at least doubling the cost of the capacity contracts – and it would require substantially longer lead times to commission new capacity – up from 2–3 years to 4–5 years. In addition, the duration and scale of capacity contracts would have to match the minimum efficient scale of gas plants with CCS.

Prospects

Three or even two decades ago and in other circumstances, the prospects for CCS applied to coal generation might have been much brighter. However, in 2017 there is still no carbon capture unit installed at a coal plant operating on a commercial scale. The experimental units at Boundary Dam and Kemper County have incurred FOAK costs that are at least 2–3 times the NOAK costs claimed by advocates of the technology. To close the gap will require the installation of carbon capture at plants with a total capacity of at least 100 GW, implying an investment of about $600 billion with an annualised cost of $60–100 billion per year. The timescale required to prove the technology and to bring costs down to NOAK levels is likely to be 20–30 years. Who is supposed to cover the cost of learning up to 2040 or 2050? It is not obvious that either the taxpayers or the electricity consumers in OECD countries would be advised to foot the bill. The only country with both the resources and a potential interest is China. But at the moment it seems that they have chosen the route of nuclear power instead.

The prospects for CCS applied to gas plants are even more uncertain. One reason is a difference in views about the energy costs of regenerating solvents. The optimistic view is that the parasitic consumption can be kept below 8% for baseload plants, while more cautious estimates assume that the parasitic consumption will be much higher (12–15%). In addition, the penalty for operating under partial load (down to 50% of capacity) and for frequent ramping up/down is rarely examined. This can only be established in the light of the experience of operating commercial gas plants with carbon capture. Adding carbon capture to a typical 650 MW gas CCGT is expected to double its cost on an NOAK basis, so the investment required to move down the learning curve would be somewhat lower than for coal, although still large. It is conceivable that US policymakers might consider this cost to be acceptable, though it would require the prospect of an implicit carbon price approaching $150 per tCO_2 to justify the addition of carbon capture to a new gas CCGT constructed before 2030. There is little evidence that such a carbon price would be observed in any reasonably efficient carbon market or that it would be acceptable to the electricity consumers who would be required to cover the cost. This price is at least double reasonable estimates of the social cost of carbon.

In summary, the economic analysis of CCS suggests that it is a technology that is both too late and too expensive in its current form. Advocates of greater expenditure on R&D in CCS tend to start from the position that the technology is a critical requirement if the concentration of CO_2 in the atmosphere is to be controlled at reasonable cost. That conclusion may still be correct in a centrally planned world, though it would be more convincing if the rate of technical development had been faster and the level of costs had been brought down more rapidly. But we do not live in a centrally planned world and power systems in 2017 are no longer controlled by vertically-integrated monopolies that can recover their costs from captive customers. On top of that, muddled policies to support a variety of 'low-carbon' forms of generation have undermined both system stability and incentives for investment in the kind of baseload plants that are the prime target for CCS.

The two major markets for applying CCS to coal plants are China and India. However, both countries are close to the limits of their domestic coal industries with output being more likely to fall than to increase in future decades.[23] Both countries have begun to import large quantities of thermal coal for use in coastal power plants – nearly 100 million tonnes per year in the case of China. Rather than increase the volume of imports to fuel new coal plants they are more likely to switch to a combination of gas and nuclear power. This change in direction is already clear in China and has been signalled in India. Of course, the development of new coal plants will not stop abruptly, but if CCS were to approach maturity in two decades from now the flow of new coal plants to which it might be applied in China and India will be much lower than now. If, as experience suggests is likely, the cost of retrofitting carbon capture to mid-life coal plants is much higher than installation at a new plant – even assuming that retrofits are feasible - the enthusiasm for adopting CCS on a large scale in either country will be negligible.

The market opportunities for installing carbon capture at gas plants are much larger. The economic analysis suggests that as long as the gas price is less than twice the coal price (measured on a heat basis) the cheapest way of reducing CO_2 emissions from existing coal plants is to retire them and build new gas plants fitted with carbon capture. However, the main application will not be for baseload plants but in plants with an average load factor below 60% and requirements for efficiency operation down to 50% load as well as rapid ramp rates going from start or 50% load to full load. At the moment, this requirement receives little attention in R&D on carbon capture and it is not clear how it would affect the design and costs of carbon capture units.

A probabilistic analysis by Rubin & Zhai (2012) suggested that a carbon price in excess of $100 per tCO_2 would be required to warrant the installation of CCS at the majority of new gas plants. Their assumptions about load factors, gas prices, etc were much more favourable to CCS than would be reasonable in 2016, so the probabilistic breakeven carbon price today would be close to \$150 per tCO_2. There must be considerable doubt about whether the public will be willing to accept the implications of such a carbon price in the next two decades. On the other hand, allowing for the higher capital costs that will be incurred during the learning phase of the new technology implies that investment in carbon capture for new gas plants will only occur if the prospective price of carbon in 2030 or later exceeds \$150 per tCO_2 at 2015 prices.

Acknowledgements

I am grateful to John Constable and Andrew Montford for comments on earlier versions of this paper. The views expressed in this paper are strictly my own and do not represent the position of any organisation with which I am affiliated.

Notes

1. Data on GHG emissions extracted from the 2016 version of the Climate Analysis Indicators Tool (CAIT) version 2 developed by the World Resources Institute – see http://cait2.wri.org.
2. The term 'tonne' is used to denote a metric ton (mt) of 1000 kg in order to distinguish between the metric unit and the American ton of 2000 pounds.
3. The project database of the Global CCS Institute includes 17 large CCS projects in operation by the end of 2016 with total CO_2 capture of 33.9 million tonnes per year. Of this total 31.3 million tonnes per year is used for enhanced oil recovery.
4. Renewable obligations in the US are usually known as Renewable Portfolio Standards (RPS). They are implemented by state legislation and/or regulation, so there are wide differences in requirements across the US.
5. At 2015 prices
6. At 2008 prices.
7. See Songhurst (2014).
8. LNG projects in Australia have proved to be particularly expensive, partly because of their location and partly because huge expenditures on natural resource projects have pushed up the Australian dollar and caused a general increase in the cost of non-traded goods and services – a variant of what is known as Dutch disease. These Australian projects were excluded in arriving at the conclusions on cost trends.
9. Rubin, Davison & Herzog (2015). Rubin and Herzog were two of the authors of a study of CCS costs produced for the IPCC in 2005 – IPCC (2005). Rubin has published several other papers on the topic and the joint authors of the recent review are among the most expert analysts in the field. They provide an assessment of how costs have changed over the decade from 2004 to 2014. The detailed components of the cost estimates are discussed in Appendix B. The Rubin et al costs are quoted in US dollars at 2013 prices. I have applied a cost escalation of 5% to their figures (because contracting costs in the US have risen faster than retail prices due to the economic recovery) and rounded all estimates down to the nearest $100 per kW or an equivalent level of accuracy. There is no basis for pretending that cost estimates are more accurate than this.
10. The Global CCS Institute's database of large scale projects in operation, development or evaluation lists no projects for carbon capture for gas turbines for the period up to 2025. The one project that would have qualified – at the Peterhead power station near to Aberdeen – was cancelled by the UK Government in 2015. While this decision was criticised as being short-sighted, the reported cost of the proposed project - £1 billion for 385 MW or nearly £3,000 per kW - was extremely high even before any likely cost escalations. To bring this cost down to the NOAK level discussed in Section 6 below would require cumulative installations of at least 100 GW and an expenditure of at least $200 billion. Notwithstanding the views of project participants and supporters, it is understandable that a government might decide that this was not the best use of public funds.
11. See IEAGHG (2015)
12. There are other oxy-combustion cycles being developed but the Allam Cycle being tested by NET Power seems to have the highest efficiency and best prospects at present.

13. The publicity surrounding the NET Power demonstration project is somewhat misleading. The plant is reported as being 50 MW but this is the thermal input rather than electricity output. Different reports cite net efficiencies of 55–60% LHV and even larger ranges for the cost of construction. Overall, this is a long way from being a proven or economic technology. Other oxy-combustion technologies are even more immature.

14. Higher heating value.

15. See https://www.gov.uk/government/speeches/amber-rudds-speech-on-a-new-direction-for-uk-energy-policy.

16. The difference arises because the ratio of CO_2 captured to CO_2 avoided is higher for coal plants than for gas plants due to the high parasitic consumption of carbon capture at coal plants.

17. At 2015 prices

18. Asian Development Bank (2013, Chapter 6).

19. Conditions would appear to be more favourable in East Asia, with an average ratio of 3.9 over the last two decades but this reflects the post-Fukushima spike in LNG prices and the limited size of the LNG market prior to the late 1990s.

20. For dispatch alone the breakeven carbon price would vary from \$45 per tCO_2 for a gas price of \$6 per MBtu to \$70 to tCO_2 for a gas price of \$12 per MBtu. The peak spot price for gas in the UK in late 2013 was below \$12 per MBtu, while the forward price for Winter 2018 is below \$6 per MBtu. Note that this breakeven price would not be sufficient to cover the capital costs of CCS.

21. This assumes that the average cost of gas plants fitted with CCS will be 25% higher than NOAK estimates as the technology moves down the learning curve.

22. There would be a minor offset via a reduction in the cost of payments under the CfD contracts for renewables and the deal for nuclear power from Hinkley Point and other new projects.

23. The Chinese government is planning to close mines with a production capacity of more than 500 million tonnes per year for environmental and safety reasons. While the larger mines may expand in future, the trend of growing coal production has clearly reversed and the share of coal in China's primary energy use will decline over the next 10–20 years.

Appendix A: Market prices, dispatch and investment in the UK

Levelised costs, which are usually used for academic and official studies of the economics of carbon capture, are of limited value in understanding the decisions made by investors and generators when operating in power markets. This appendix provides a simplified description of the factors which actually underpin those decisions. It is simplified because I will ignore factors such as the scheduling of regular maintenance, the ramping costs of starting or stopping plants, the differences between cold, warm and hot starts, revenues from bidding into the balancing market, and so on. All of these may affect the number of hours operated over a year and the costs incurred, but the simplification does not distort the main story.

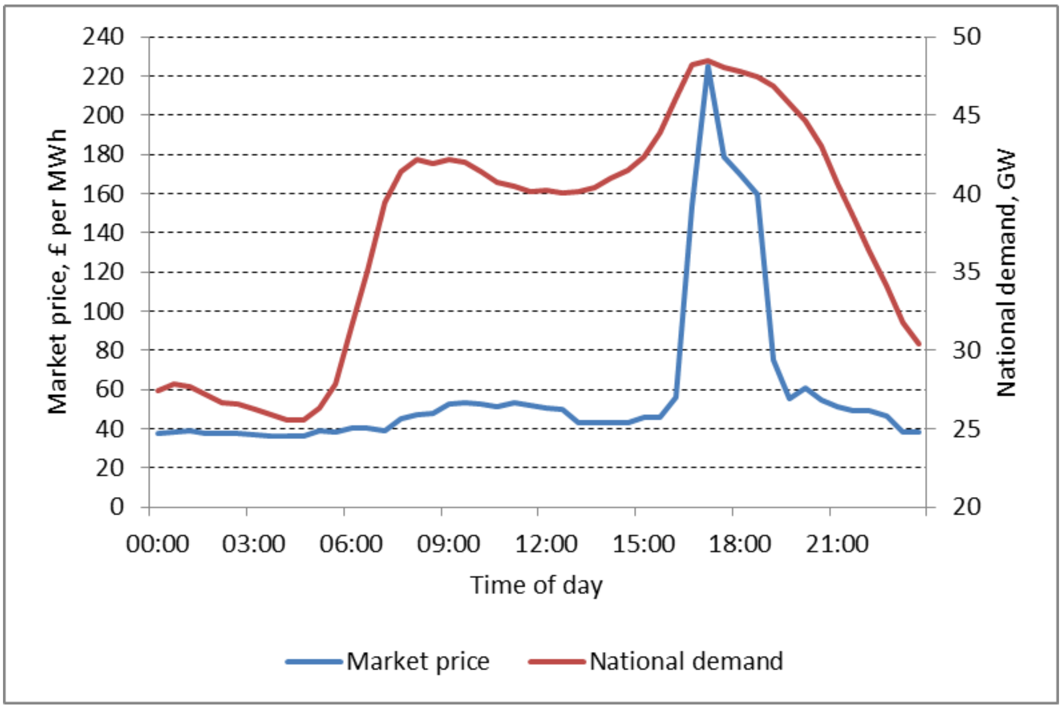

Figure 1: Wholesale market prices and power demand on 28th November 2016.
Source: Author's calculations based on data from National Grid and Elexon.

Figure 1 shows the evolution of demand and wholesale market prices in the GB electricity market by 30-minute settlement period on 28th November 2016. This date was chosen because it had the highest peak prices of the 2016–17 winter, partly because of cold weather and partly due to increased demand from France because of temporary shutdowns at a number of French nuclear plants. The market price was between £37 and £41 per MWh during the period of low demand up to 07:30 and after 23.00. Once demand reached 40 GW, prices rose to a range of £45 to £55 for working hours followed by a very sharp peak when demand exceed 46 GW between 16:00 and 20:00.

In each 30-minute time period the market price is primarily set by the variable cost incurred by the most expensive plant required to meet demand. Hence, prices during the four-hour peak period were very high because it was necessary to pay generators with high variable costs – perhaps due to high fuel costs or low thermal efficiency – to operate. The prices had to be sufficient to cover their costs of starting up and then shutting down after operating for 2, 3 or 4 hours.

Now, consider the decision made by a generator with a base variable operating cost of £50 per MWh. It would choose not to supply power until the market price reached that level – at 09.00 – and would earn a small margin over its base cost up to 13.00 when the price went below £50. It could either shut down or operate at a loss up to 16.00 when the price reached £55 and would then make a large margin until 21.30 when the price fell below £50 for the rest of the day. This is a typical pattern for a generator on two-shift operation covering the morning and evening peak demand periods. For most of its operating hours it would earn a margin of less than £5 per MWh to contribute to fixed capital and operating and maintenance (O&M) costs. Its real incentive was an average margin of over £110 per MWh earned in the three-hour evening peak from 16.30 to 19.30.

Such periods of high returns are infrequent and very uncertain. The pattern of peaks changes from day to day. For example, the average market prices for the weekdays from November 28th to December 2nd would indicate operating from 07.30 to 11.30 with a margin of £7 per MWh and from 15.00 to 21.00 with a margin of £30 per MWh. This was the best week of the winter, but the plant would only operate for an average of 10 hours per day and earn a margin of £1,050 per MW of capacity during the week – hardly a large return to cover the capital investment, fixed costs and risks required to construct the plant and keep it in operation.

Figure 2 shows the distributions of market prices and power demand for all of 2016. The market price was less than £34.7 per MWh in 50% and less than £42.3 in 75% of all periods. Hence, a power plant with a base variable operating cost of £50 per MWh would only be able to cover its variable costs in 12.5% of periods; in other other words, it would operate for a maximum of 1095 hours per year. In practice, this is too optimistic, since many of those periods would be isolated or would extend over less than 2–3 hours: it would not be worth incurring the costs necessary to start and stop the plant for such brief periods. Thus the load factor of such a plant might be less than 10%, spread over the year. A plant with a base variable operating cost of £30 per MWh might be able to achieve a load factor up to 83% over the year, whereas a plant with a base variable operating cost of £40 per MWh would not reach a load factor of 30%.

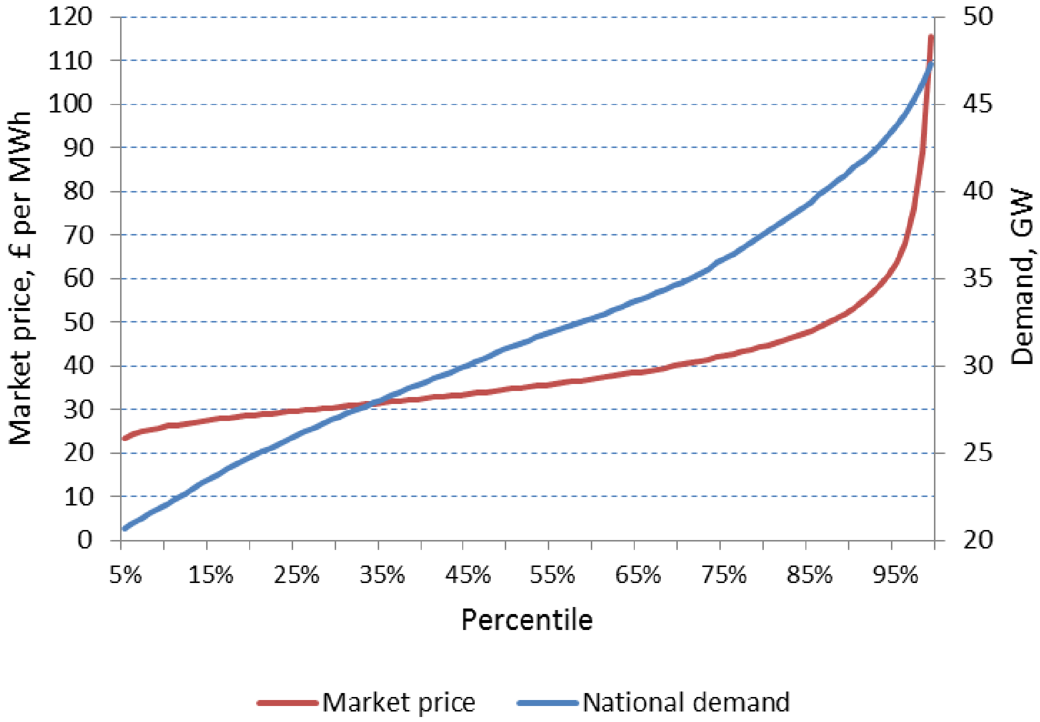

Figure 2: Percentiles of market prices and power demand for 2016.
Source: Author's calculation based on data from National Grid and Elexon.

Small differences in variable costs can translate to huge differences in the expected load for a plant. Figure E3 shows the amount of gas generation dispatched in each settlement period in November 2016 when market prices fell in the range from £30 to £50 per MWh.[24] The solid blue line is a quadratic fit to the data. At current gas prices and market conditions, an increase from £35 to £45 per MWh in the market price led to an increase of 7.2 GW in the amount of gas generation capacity that was dispatched. A plant that can be dispatched at £35 per MWh might expect an annual load factor of about 45%, whereas one that can only be dispatched at £45 per MWh would have an expected load factor of no more than 15%. The average dispatch margin in 2016 for a gas plant operating with a load factor of 45% and a dispatch price of £35 per MWh would be about £12 per MWh. This is well below the margin of £26 per MWh required to cover its capital and fixed operating costs.

Investment decisions in competitive power markets are not made on the basis of levelised costs. Rather it is the factors highlighted by this analysis of the power market in 2016 that are central to such decisions. There are two questions that must be addressed when considering an investment in a new gas or coal plant.

- Given the expected distribution of power prices over the year, the operating

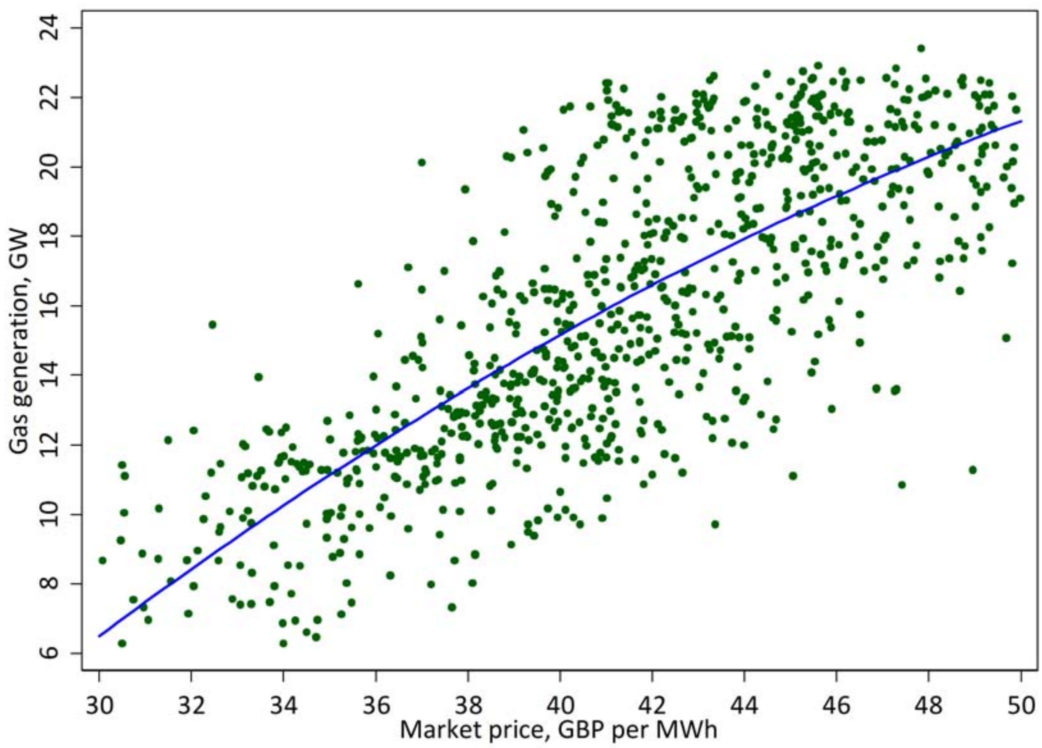

Figure 3: Market prices and gas generation in November 2016.
Source: Author's calculations based on data from National Grid and Elexon.

costs of a new plant, the price of gas, and so on, what load factor would be expected for the plant; that is, for what proportion of the year is the expected market price greater than the projected dispatch cost for the plant?

- What is the expected dispatch margin averaged over the hours in the year in which the plant would be expected to be dispatched?

The answers to these questions depend on the level and shape of the market price distribution shown in Figure 2. At 2016 values for gas prices and carbon taxes, the dispatch price for a new gas plant without carbon capture would be £40–43 per MWh after allowing for ramping costs; for a new plant with carbon capture it would be £44–49 per MWh. Even with the low end of the range a new plant without carbon capture would not be dispatched for more than 25% of hours in the year. A new plant *with* carbon capture would expect to be dispatched for less than 15% of hours in the year.

As a starting point, these load factors are likely to discourage any consideration of new investment because the fixed costs would have to be recovered over a relatively small number of operating hours, requiring either a very steep upper segment of the price (above the 80th or 90th percentile), or some form of non-market intervention such as capacity payments to cover some or all of the fixed costs. Experienced power investors will have little confidence in a steeply rising price distribution. The reason is that price spikes have severe consequences for consumers and tend to prompt government intervention in markets, such as price caps or moves to reduce the 'excess' profits that are allegedly being made.

For new investment to be considered without external intervention, the price distribution would need to shift upwards by £10–12 per MWh relative to its level in 2016 as a result of structural changes, not because of an increase in gas prices or carbon taxes. Subsidies for investment in wind and other renewable generation tend to shift the price distribution downwards, as does the secular decline in electricity demand. Hence unless operators decide to retire a lot of current generating plant, the prospects for market-driven investment in new gas capacity look very poor for the next decade.

Even if the distribution of market prices were to shift upwards, the shape of the distribution is too flat for any investor to expect to earn an adequate return (after allowing for risk, and so on) by building a new gas plant without carbon capture. This is illustrated by Figure 4, which compares the distribution margin for a range of load factors in 2016 with the margins required to cover fixed costs for new gas plant without or with carbon capture. If a load factor of 85% could be achieved, the distribution margin in 2016 was only £1.5 per MWh below what would be required to justify investment in plant without carbon capture. The gap widens as the load factor falls and is £9 per MWh for a load factor of 55%, which is a more reasonable basis for evaluating a new plant. Adding carbon capture would push up the distribution margin required to cover fixed costs by £30 per MWh for baseload plant and by £47 per MWh for mid-merit plant with an expected load factor of 55%.

The core mistake in relying upon estimates of levelised costs is that the calculations treat the load factor of a plant as if it is determined exogenously. An investor in a competitive power market cannot make that assumption. When – and for how many hours a year – a new plant will be dispatched is determined by the characteristics of new plant relative to the fleet of existing plants. The structural factors that influence the shape of the distribution of market prices are critical. At the moment, these are very unfavourable for any kind of new investment in new gas plants, even without carbon capture, and there is no obvious reason why this situation should change before 2025. If new investment is deemed to be essential, the only remedy is to offer either capacity contracts or guaranteed prices (via CfDs). The two mechanisms have different incentive properties which would affect the willingness of investors to install carbon capture as well as the level of subsidy required.

With a capacity contract, the minimum dispatch price of a new gas plant without carbon capture would be about £48 per MWh, which implies a load factor of about

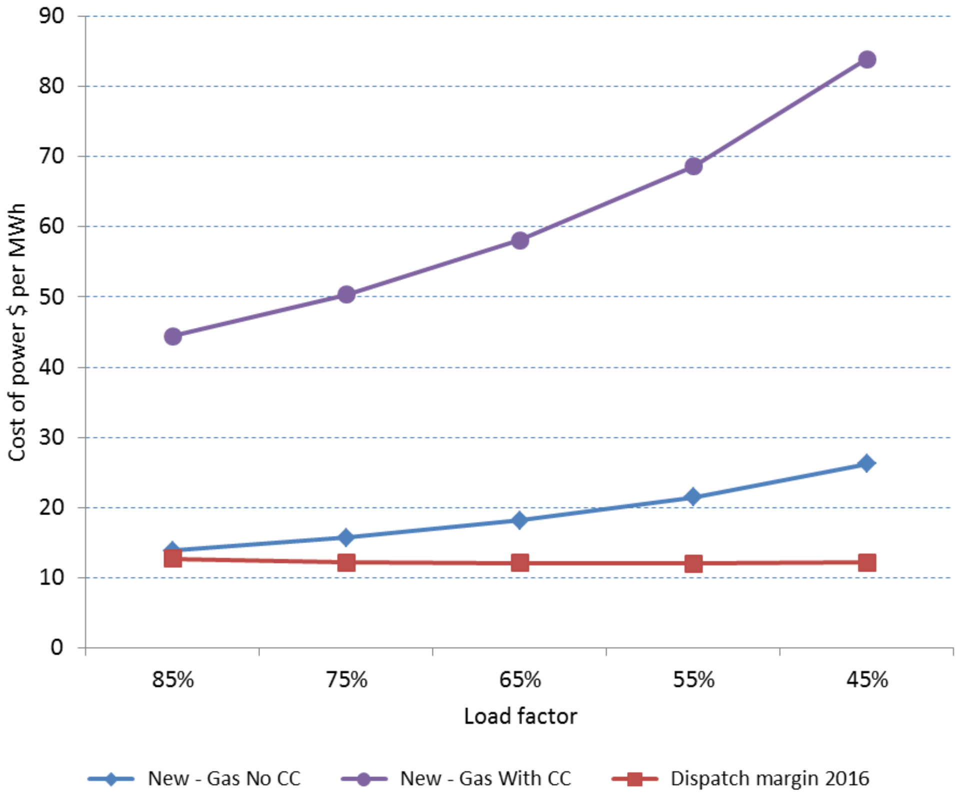

Figure 4: Dispatch margins for gas plants by load factor.
Source: Author's calculations

15% or roughly 1300 hours of operation per year. The dispatch margin with that load factor would be £15 per MWh, earning £19,500 per year per MW. Fixed costs would be about £103,000 per MW per year, so the capacity payment required would be close to £83,500 per MW per year. For a new plant with carbon capture, the dispatch price at 2035 costs would be close to £60 per MWh, implying less than 600 hours of operation per year and a total distribution of £10,500 per MW per year. Since fixed costs would be about £330,000 per MW, the capacity payment would have to be nearly £320,000 per MW per year or nearly four times the level required for a plant with no carbon capture. The penalty for installing carbon capture would be huge and would be hard to justify for a plant operating for such a small number of hours per year.

CfDs are only offered for low-carbon methods of generation, so they would not be available to new gas plants without carbon capture. Because the contract guarantees a price, the market price is irrelevant to the generator, although it will affect the level of subsidy required. A new gas plant with carbon capture with a CfD contract might expect to operate on baseload with a load factor of 85% or higher and would receive an average market price of £41 per MWh over the 2016 distribution of prices. The CfD guaranteed price would have to be about £89 per MWh, implying a subsidy of £48 per MWh or £358,000 per MW per year. The cost of support is higher than under a capacity contract but it yields a much greater level of output and reduction in CO_2 emissions. In this respect the CfD approach may be seen as being preferable to a capacity contract if the goal is to reduce CO_2 emissions as well as to provide security of supply. Nonetheless it is extremely expensive in aggregate if it has to be applied to a large amount of new capacity.

This prompts a further observation. The assumption that new gas plants with carbon capture will operate on baseload only applies for relatively small amounts of new capacity. Baseload demand is 20–24 GW, of which nuclear can supply 8 GW, wind up to 8 GW, biomass and other renewables 2 GW, and the various interconnectors up to 4 GW. Even if some of the interconnectors are not bid into the market during low-demand periods, gas plants will be competing with wind generation during periods of high wind output and many generators of both types would be receiving CfDs or other output-based subsidies. The effect would be to push down market prices during periods of low demand and high wind output. As a consequence, potential investors in new gas plants with carbon capture would adjust their expected load factor, pushing up both the minimum CfD price that they would require to £95–100 per MWh. The higher guaranteed price would be offset by the reduction in the number of hours of operation per year, so the best deal in aggregate might be a guaranteed price of £100 per MWh with an expected load factor of 65%. However, such contracts would look expensive relative to the CfD prices for nuclear plants.

Increasing the carbon floor price to £40 per tCO_2 would add £16–20 per MWh to the dispatch prices for coal plants and £7–9 per MWh to the dispatch prices for gas plants. This would push up the general level of the market price distribution and flatten it for high load factors (low percentiles) as newer gas plants displace older coal plants. However, coal plants now account for a relatively small portion of baseload and mid-merit generation – typically 2–3 GW – so the overall effect would be higher power prices without a substantial reduction in CO_2 emissions from power generation or a significant stimulus to new investment in gas plant without or with carbon capture.

While market conditions differ across developed countries, the general conclusion remains valid. There is little prospect that gas plants with carbon capture will attract investment in competitive power markets in which renewables and/or nuclear power play a significant role. The only way of ensuring such investment would be to offer subsidies via CfDs or alternative arrangements that guarantee dispatch as well as covering capacity costs. In effect, this would amount to an abandonment of the principle that power prices should be set in decentralised competitive markets in favour of centrally determined pricing and investment decisions.

Many countries have implemented policies for electricity based upon an assessment of the viability of specific technologies: renewables, nuclear power, carbon capture, and so on. Power markets are complex and the outcomes of such interventions are rarely as straightforward as expected in advance. With assets that may operate for 20 to 50 years, poorly designed interventions cast a long shadow and lead to investment cycles that destabilise markets. Such policies will often have large unintended consequences, which should have been foreseen and might have been avoided by more deliberate action.

Notes

24. The spot market price of gas was relatively stable over the month, removing this as a factor influencing variations in the amount of gas capacity that was dispatched in each period. All generators would ensure that their capacity was available for dispatch during the peak demand period of the year, so maintenance schedules and similar considerations would have a minimal effect on availability.

Appendix B: Marginal abatement costs for power plants

Standard presentations of the costs of using CCS to reduce CO_2 emissions ask the wrong question and thus get the wrong answer. They ask: 'How much does it cost per tCO_2 avoided if carbon capture is fitted to a coal/gas plant'. However, this does not take account of the choice between coal and gas as the primary fuel, which has a large impact on the level of CO_2 emissions.

Figure 5 illustrates the MACs per tCO_2 for all reasonable combinations of coal/gas, with or without carbon capture, at a range of plant load factors from baseload (85%) to low mid-merit (45%). The costs are sensitive to the ratio between the fuel prices on a common heat basis. The figure is constructed on the very conservative assumption that the price of gas per GJ HHV is three times the price of coal on the same basis. This value is equal to or greater than the 90th percentile of the annual average ratios of gas to coal prices for the UK, Germany and the USA over the last 30 years. The ratio was larger for Japan for 2012–15 because of its reliance upon oil-indexed LNG contracts after the Fukushima earthquake.

The abatement option which consistently has the lowest marginal cost is switch-

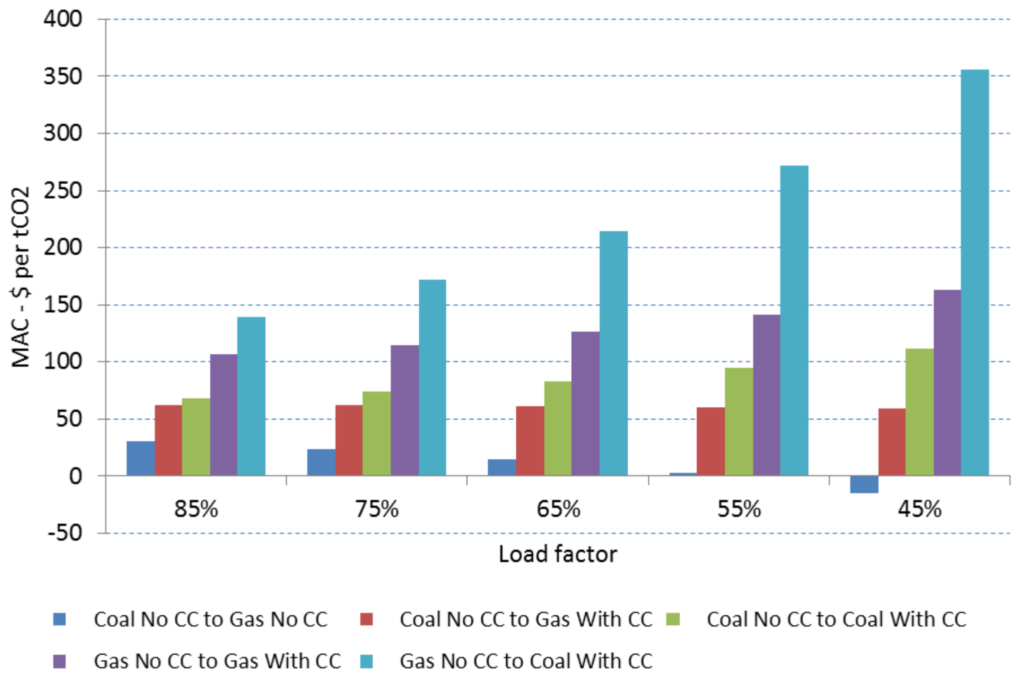

Figure 5: MACs based on NOAK construction costs.
Source: Author's calculations based on Rubin et al (2015)

ing from coal with no carbon capture to gas with no carbon capture. The calculations shown do not take account of the benefits of flexibility and the costs of ramping output up or down. If these are factored into the decision, a gas plant would be preferred to a coal plant if the expected load factor is less than 60%, without any consideration of CO_2 emissions. Further, switching from coal without carbon capture to gas *with* carbon capture has a lower MAC than installing carbon capture at a coal plant for all expected load factors.

In practice, these figures are much more favourable to carbon capture than is warranted for any discussion of policy over the next two decades because they are based on NOAK costs that will be not achieved until sometime between 2040 and 2050. For the 2030s the base capital and O&M costs will be at least 50% higher on the (optimistic) assumption of a learning rate of 15%, which will be required to get down to NOAK costs by the 2040s.[25]

Using these costs – referred to as 2035 costs – the MAC of using carbon capture to reduce emissions is substantially higher, as shown in Figure 6. The cheapest option of switching from coal to gas with no carbon capture is not affected by learning, whereas

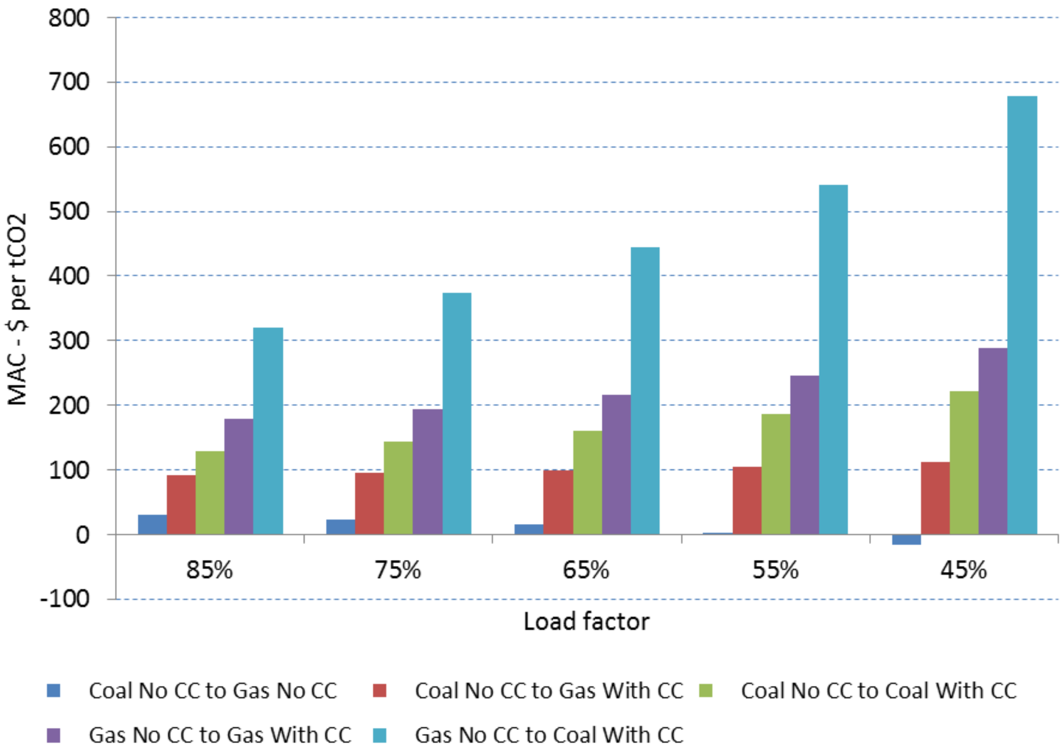

Figure 6: Marginal abatement costs based on 2035 construction costs.
Source: Author's calculations based on Rubin et al (2015).

the alternative of installing coal with carbon capture instead of gas with no carbon capture has a MAC that is over \$300 per tCO_2 for a baseload plant, or nearly \$450 per tCO_2 for a mid-merit plant with a load factor of 65%. The MAC if carbon capture were to be installed at new gas plants would be \$178 per tCO_2 for a baseload plant and \$246 per tCO_2 for a typical gas plant operating with a load factor of 55%.

Figure 7 illustrates the impact of a carbon tax on the choices that would be made by generators in the next two decades when not subject to specific regulation requiring the installation of carbon capture. With a carbon tax of \$25 per tCO_2 – a little above the current floor price in the UK – gas plants have a small cost advantage over coal plants for baseload operation, even if the expected price of gas is three times the expected price of coal. The margin is larger the lower is the expected load factor. Adding carbon capture would increase the cost of power from a gas plant with an expected load factor of 55% from \$93 to \$160 per MWh. No generator would be willing to invest in gas plants with carbon capture to supply a competitive power market because of the frequency of dispatch and also because the average margin between the power price and variable operating cost would be too low to cover fixed investment and O&M costs. This highlights the difficulty of trying to force generators to install or retrofit carbon capture units to plants that will operate in markets where the price of power is set most of the time by plants without carbon capture. In this case the guaranteed price under a Contract for Differences (CfD) scheme would have to be higher than the level (\$115 per MWh) for nuclear power from Hinkley Point.

Increasing the carbon tax to either \$50 or \$100 per tCO_2 is not sufficient to avoid the problem (see Figures 7b and 7c). At the higher tax level, coal plants without carbon capture would be displaced by gas plants with carbon capture, but only if the expected load factor is high enough. The carbon tax would have to be greater than \$200 per tCO_2 before it would be economic to fit carbon capture at gas plants built in the next two decades with an expected load factor of 55%.

There is a further consequence of these results. The standard economic argument is that a carbon tax is an efficient way of promoting the adoption of low-carbon technologies. In many cases that is true when innovation and learning operate over a relatively short period. However, electricity systems and markets are complex and involve investments that have long operating lives. Relying upon carbon taxes to promote the adoption of CCS, which is still at the very early stage of learning, is likely to impose huge deadweight losses on an economy. It will, in particular, commit a country to electricity prices at levels that may slow the adoption of other low-carbon technologies.

Instead, policymakers should set any carbon tax at a level that reflects the social cost of carbon and not by reference to promoting specific technologies for power generation. If a good case can be made that carbon capture will be economic in the longer term, which is far from certain, other policy instruments will be required to stimulate the learning and cost reductions that are required.

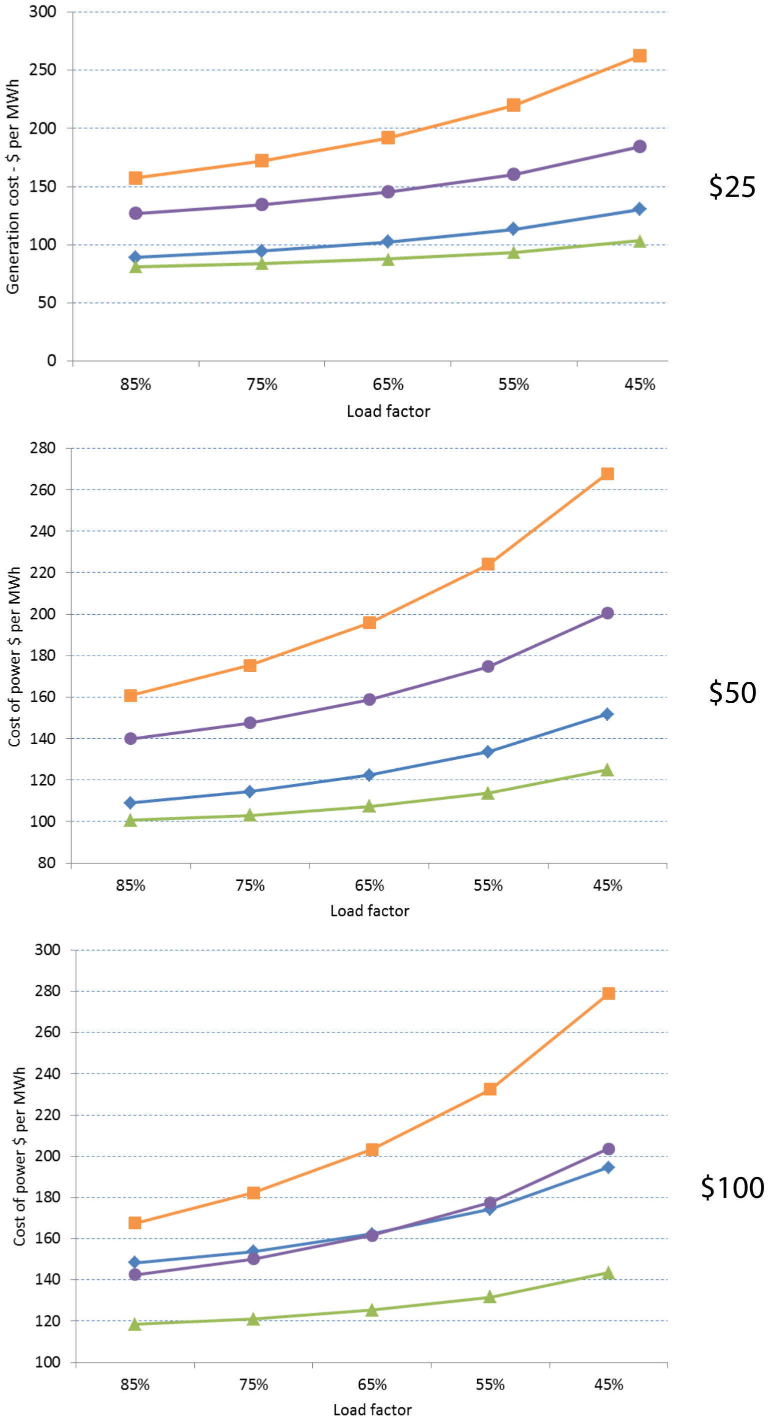

Figure 7: Power costs at various carbon tax levels based on 2035 construction costs.
Key: orange, coal with CC; purple,gas with CC; blue, coal no CC; green, gas no CC.
Source: Author's calculations based on Rubin et al (2015).

Notes

25. With a learning rate of 15% and a period of 4 years between each doubling of cumulative investment, which is the minimum that can be expected with plants that take 3 or 4 years to build, the costs of building carbon capture units should fall by about 33% per decade.

Appendix C: The social cost of carbon

In order to consider whether the cost of reducing CO_2 emissions by deploying CCS is reasonable or not, it is necessary to establish some kind of benchmark concerning the amount that collectively we are – or should be – willing to pay to reduce levels of CO_2 in the atmosphere. One standard benchmark used by economists is referred to as the social cost of carbon (SCC). The calculations that underpin estimates of the SCC are inevitably both technical and controversial, but the core approach is relatively simple.

The analysis starts with a model of how the global economy will develop over a time horizon of 50, 100 or 200 years with different levels of CO_2 in the atmosphere and various assumptions about the physical and economic processes by which climate variables affect countries and sectors including, for example, agricultural output, spending on heating and cooling, damage due to sea level rise and extreme weather events, the impact of epidemics and heat waves, and so on. Now, we perturb a baseline scenario by assuming that emissions of CO_2 are perhaps 1 gigatonne (Gt) higher in 2020 than in the baseline and then we add up all of the differences between economic activity and welfare in the baseline scenario and the perturbed scenario in each year or in each five-year period. The belief that CO_2 creates a negative externality implies that the sum of these changes over the time horizon will be negative; that is, global welfare is lower as a consequence of the emission of an extra 1 Gt of CO_2. The SCC in 2020 is then the sum of the changes in welfare expressed per tCO_2 of additional emissions in 2020.

While calculations of this kind are necessarily approximate and highly aggregated, there are two important issues on which different assumptions may lead to very different estimates of the SCC. The first concerns whether different weights should be attached to equal monetary changes in welfare in different countries. Should $1 million loss of welfare for residents of the US be given the same weight as $1 million loss of welfare for residents of west Africa? If not, how should we take account of the fact that the US is – and is likely to remain – richer than west Africa? The second issue is related to the first because it concerns the weight that should be given to changes in welfare that occur in 2025 relative to those that occur in, say, 2075 or 2125. In daily life and policymaking it is standard to discount both benefits and costs that are expected to occur 5 or 10 years in the future relative to those that occur now or next year. Should we extend the process of discounting many decades into the future and at what rate? Consistency might suggest that looking forward from 2020 to 2030 is the same as looking forward from 2080 to 2090, but if we adopt that approach it is almost certain that costs arising in 2090 due to emissions in 2020 will be given very little weight in the calculation of the SCC.

The two issues are related because one reason for discounting future costs or benefits is that we anticipate that people, whether in the US or west Africa, are likely to be significantly better off in 2090 than they are in 2020. So, bearing the cost of reducing emissions in 2020 in order to benefit people in 2090 is, in effect, a transfer from people who are relatively poor to others who are relatively rich. On grounds of equity might we not prefer to spend the same resources to assist those who are poor in 2020? These are matters of social philosophy and values on which there can be large but reasonable differences in key assumptions. These, in turn, may feed through to large variations in estimates of the SCC. This is unavoidable because analyses suggest that the welfare impacts of climate change differ greatly over space: they are worse in poor, hot and coastal regions, so policies to reduce poverty and promote economic growth will also mitigate the impacts of climate change. In addition, the initial impacts of climate change may be positive, but negative impacts dominate in the longer term and may be particularly large a century or more into the future.

The literature on the SCC is now so large that there are reviews of reviews. Tol (2013) reports that the mean value of 588 estimates of the SCC in 2010 (in 2010 US dollars) is \$196 per tonne of carbon (tC) whereas the modal value is only \$49, so the distribution is heavily skewed with a small number of very high values.[26] The most important source of difference is the rate of time preference, which underpins the discount rate. The mean SCC with a rate of time preference of 1% (implying a relatively low discount rate) is \$105 per tC; the mean SCC with a 3% rate of time preference (yielding a discount rate similar to those used for other public policies) is \$25 per tC.

Across a range of reviews of the SCC the selection of the discount rate or the rate of time preference is consistently the most important factor determining the SCC. The relationship between the two is important because it reflects assumptions about the weight that is given to the welfare benefits of future economic growth, which is not a global constant. For developing countries, including important emitters such as China, India and Indonesia, the current discount rate is likely to be equal to the rate of time preference plus 5% or more, though it is likely to fall as they become richer. For the USA the difference between the rate of time preference and the discount rate may be only 2–3%. Hence, a standard assessment of the impacts of climate change will give rise to widely varying estimates of the SCC. This is not an indication of mistakes or malign intent but rather it is a direct consequence of the fact that the trade-offs between current and future welfare may be viewed differently by countries at different stages of development and facing different economic prospects.

There is no 'right' estimate of the SCC and we should not expect that the upper limit on what is spent on reducing CO_2 emissions will be the same in all countries. The EPA (2016) has published estimates of the SCC for use in regulatory impact analyses. Their central estimates are based on a discount rate of 3%, which implies both a very low rate of time preference and pessimistic assumptions about future economic growth. Even then, the estimates of the SCC are \$48 per tCO_2 for emissions in 2020 and \$78 per tCO_2 for emissions in 2050 at 2015 prices. At a discount rate of 5% – in the middle of the range prescribed for other regulatory impact assessments – the SCC is estimated to be \$12 per tCO_2 in 2020 and \$26 in 2050. The EPA figures are broadly consistent with the average estimates reported by Tol: \$7.4 per tCO_2 with a rate of time preference of 3%, and \$31 with a rate of time preference of 1%.

The conclusion from the literature is that the value of reducing CO_2 emissions is very unlikely to exceed \$100 for rich countries prior to 2050 unless a very low discount rate is adopted and/or extremely pessimistic assumptions are adopted about the consequences of climate change. Those who advocate much higher values for the benefits of reducing CO_2 emissions are rarely willing to acknowledge that this implies a huge transfer of resources and welfare from the current generation to those living 50 or 100 years from now who are likely to be much better off – even allowing for the impact of climate change – than those who will pay the bills today. Hyperbolic language about the 'future of the planet' is no substitute for a careful accounting of costs and benefits, identifying those expected to pay as well as the prospective beneficiaries. As options for adapting to climate change are identified and examined, estimates for the potential damage caused by climate change after allowing for adaptation tend to fall substantially because it becomes clear that there are many ways in which economies and societies can adapt at low cost provided that adequate lead time is allowed for the modification of infrastructure and the adoption of measures to minimise, for example, the impacts on health and extreme weather events.

Since growth in per-capita income for the next four to five decades is expected to be higher in developing countries than in OECD countries, the discount rate applied in calculating the SCC for developing countries ought to be significantly higher than for rich countries. Even a margin of 2% higher in the discount rate – relatively low based on current and prospective growth rates for low- and middle-income countries such as China, India and Indonesia – implies that the value of reducing CO_2 emissions to developing countries will be well below \$50 per tCO_2 up to 2050.

The corollary of the conclusion that developing countries such as China and India are very unlikely to be willing to pay more than \$50 per tCO_2 to reduce CO_2 emissions is that OECD countries would be better spending money on reducing emissions in developing countries instead of spending (much) more than \$100 per tCO_2 on CCS for their domestic power systems. This, of course, is the case that can be made for international agreements based on tradeable CO_2 permits. The potential benefits in East Asia of such arrangements are explored in ADB (2013). In the present context the options offered by regional or wider schemes for carbon trading are likely to reduce the amounts that agents in rich countries are willing to pay for the application of CCS.

Notes

26. Divide by 3.67 to obtain the SCC per tCO_2. Tol's review is updated to 2015 in Tol (2015). The distribution of estimates of the SCC remains highly skewed with no clear trend up to 2014 and high sensitivity to extreme values in a small number of studies.

Appendix D: Lessons from pilot projects

Boundary Dam

The Boundary Dam project in Saskatchewan is an object lesson in the uncertainties and difficulties of managing the installation of a new technology. In this case the difficulty was increased by the fact that the project involved a retrofit to an existing plant. The project was widely publicised as a model, so the disappointment over the combination of cost overruns and poor performance has been correspondingly greater.

Boundary Dam is a coal power plant that was originally commissioned in 1959. It is operated by SaskPower, the public power utility of the Canadian province of Saskatchewan. There had been a number of extensions to the plant, which had a nameplate generation capacity of 813 MW before the project started. The power plant uses low quality coal (lignite) with a high level of CO_2 emissions per MWh of output. The project design was to repower one of the 139 MW units and to retrofit carbon capture, with the CO_2 committed to use for enhanced oil recovery at the Weyburn oil field. The headline CO_2 capture rate was supposed to be 90%, but the actual storage was only one half that because of CO_2 releases at the plant and the oil field. The parasitic consumption for carbon capture was expected to reduce the net output of the unit from 139 MW to 110 MW – a loss of 21%.[27]

The original cost of the project was reported to be C$1.24 billion, but subsequent reports give figures for the completed project up to C$1.5 billion. It is not clear what these cost estimates cover but they are at least 8–10 times the cost of a simple repowering with a net output of 110 MW. The carbon capture unit has not performed up to expectations. Breakdowns and maintenance outages mean that it has operated for only 40% of plant hours. SaskPower has been unable to meet its contract obligations for the delivery of CO_2 and has incurred significant penalties. In June 2016 the CO_2 supply contract was renegotiated, reducing the expected annual revenues over the life of the plant by about a third.

As with any controversial pioneering project, it is difficult to set aside exaggerated projections or criticisms to get a realistic appraisal of the project. At a cost of $10–12,000 per net kW at 2015 prices the project cost is broadly consistent with the Kemper County project (see below), allowing for the repowering of an existing unit as well as the retrofit of carbon capture. It reinforces the conclusion that the learning rate has to be very high to get costs down to the NOAK levels cited in the literature.

The project highlights the risks of retrofitting carbon capture. At 40% availability the unit cost of carbon capture is very high[28] and could not be justified on either environmental or commercial grounds. The expected project life of 30 years seems to be too long for a repowered generating unit and it is very unlikely that it will operate at baseload for anything close to that length of time. Thus the project economics would not have added up even if there had been no cost overruns and under-performance.

SaskPower and its owners may argue that it is necessary to take such risks and incur high initial costs in order to gain experience and develop a viable technology for carbon capture. It is certainly the case that the costs of learning in this field are not likely to be small. However, it seems more likely that the project will be seen as an example of what should be avoided. Lignite is a difficult form of coal to burn in power plants under the best of circumstances, so it tends to be used where it is locally abundant and there are few alternatives. Even – especially – in the USA and Canada it makes limited sense to burn lignite rather than gas. Replacing the Boundary Dam plant with an efficient gas plant would have drastically cut CO_2 emissions at 5–10% of the cost that has been incurred.

This is really the key lesson from the Boundary Dam project. It was simply an application of the wrong technology in the wrong circumstances. CCS must be judged on the criterion of cost-effectiveness in reducing CO_2 emissions. Now – or in the future – there is very little prospect that retrofitting coal power plants with CCS will make economic sense relative to the alternative of replacing them with more efficient gas plants. It is the mirage of 'zero carbon' generation that seems to drive the proponents of such projects. From an economic perspective the approach is just silly: if the costs of zero carbon are compared with low-carbon alternatives, the marginal costs of the additional reductions in CO_2 emissions are extraordinarily high.

Kemper County

The Kemper County Energy Facility in Mississippi is a 524 MW IGCC plant designed to burn lignite from an adjoining mine. There is also a 58 MW natural gas unit. The IGCC unit has pre-combustion carbon capture using a physical solvent that is designed to remove 65% of CO_2. The captured CO_2 will be transported 60 miles and fed into a CO_2 pipeline network for use in enhanced oil recovery in Gulf oil fields. Construction of the plant began in 2010 and there was a planned completion date of 2014. As a result of modifications to the original design, completion was delayed and the plant eventually started to generate electricity in November 2016.

The authorised overnight[29] capital cost of the project was $2.88 billion, excluding the cost of the mine, the CO_2 pipeline, and certain other items. The latest cost estimate reported to the SEC by the Southern Company – the owner of the operator, Mississippi Power – was $6.9 billion in October 2016. The final cost and performance of the unit will only be known when the plant is in full operation. Making reasonable allowances for the cost of the natural gas unit and the pipeline, the cost of IGCC unit with carbon capture is at least $12,800 per MW. This is 2.5–2.8 times the NOAK cost estimates for IGCC with pre-combustion capture.

The project was originally seen as a way of diversifying away from reliance on oil and gas following the large price increases in the mid-2000s and the damage to Gulf gas production caused by Hurricane Katrina. It has become very controversial because of disputes over who will pay for the cost overruns incurred and whether Mississippi Power had the right to recover costs from utility ratepayers while the plant was still under construction. The dilemma for the regulator, the Mississippi Public Services Commission, is that refusal to allow Mississippi Power to recover most of the costs of construction risks pushing the utility into bankruptcy, hampering future investment, while increasing electricity rates will penalise consumers and energy-intensive industries in a state that has the lowest per capita income in the USA.

As the experience of the Boundary Dam project illustrates, cost overruns on this scale are not unusual for FOAK projects. However, the Kemper County project highlights the difficulty of persuading investors and/or ratepayers to accept the risks and costs of learning in the application of new technologies. The US Department of Energy committed $270 million in grants for the project and an additional $133 million in investment tax credits, but it has lost the latter because of the delay in completion. In addition, the SEC is investigating the Southern Company for failure to report the cost overruns promptly.

The main lesson that private investors are likely to take from the project is that the risks and costs of innovation and learning in the implementation of CCS, certainly for coal, are disproportionate to the potential returns. If, in addition, electricity consumers are not willing to bear these costs, there is no way of financing new projects. This is particularly contentious because the US EPA has claimed, when setting new standards for CO_2 emissions, that the Kemper County project demonstrates that CCS is a viable technology that can be implemented at reasonable cost.

Petra Nova

Not all demonstration projects go dramatically awry. The Petra Nova project in Houston provides a more positive example. It is a joint venture between NRG and JX Nippon Oil & Gas to retrofit carbon capture to a 240 MW flue gas slipstream from a 610 MW pulverised coal unit at the WA Parish power plant using an amine solvent process. The CO_2 will be used for enhanced oil recovery at the West Ranch oil field near Houston, with a pipeline distance of 132 km from the power plant to the oil field. The project is expected to yield an increase in oil production from the current 500 bbl per day to 15,000 bbl per day, worth more than $200 million per year at $40 per bbl.

Reports suggest that the project is on schedule and budget, though the latter cannot be confirmed. The carbon capture unit commenced operation in August 2016 after a construction phase lasting a little over two years. The technology is not new and the construction contract was executed by Mitsubishi, which has substantial experience in this area.

One unusual feature of the project is that the carbon capture unit does not draw power from the generation unit to which it is attached. Instead, NRG built a new 75 MW gas-fired cogeneration plant, which provides steam and power to operate the carbon capture unit with any surplus power being fed into the grid. This arrangement reduces the effective cost of operating the carbon capture unit, although the CO_2 emissions from the cogeneration unit must be set against the 1.4 million tCO_2 that will be captured.

While the Petra Nova project appears to be a successful use of post-combustion amine scrubbing, it is not clear what it demonstrates about the feasibility and costs of carbon capture as a mainstream technology. The coal units at WA Parish have a nameplate generation capacity of 2475 MW, 10 times the scale of the flue gas slipstream processed by the project. Applying the same approach to the whole plant would involve the construction of 3 × 250 MW cogeneration plants plus the use of a large area of land, which will often be difficult to find.

These issues can be solved at some cost, but it is less clear how the process will cope with the intermittency implied by regular operation of the whole plant. Few coal plants in Texas operate with high load factors because of the large incentives for wind generation in the Electric Reliability Council of Texas (ERCOT) system. Total wind capacity in Texas was 18.5 GW in mid-2016 and is expected to reach 25 GW before 2020. In addition, solar capacity is expected to exceed 5 GW within five years. System peak demand in 2016 was 70 GW, but that is a summer peak. Peak wind generation in 2016 was 14 GW, at a time when baseload was only 28 GW.[30] The economic basis of the Petra Nova retrofit seems to rely entirely upon the return from using the CO_2 for enhanced oil recovery, but that is not a model that can be scaled up either to the whole plant or to a significant number of other coal plants in the state.

The point is that carbon capture retrofits, even successful projects such as Petra Nova, must be assessed in the framework of an electricity system as a whole. What works for (relatively) small units may tell us little about the feasibility of large-scale deployment of the technology. Without any serious consideration of the consequences, the energy policies adopted by state and the federal government in Texas have almost certainly ensured that carbon capture will play little part in the state's transition to a lower carbon future. Instead, the path is very clearly towards a future with large amounts of wind generation, some solar generation plus gas-fired generation to smooth the intermittency of renewable generation. Adam Smith referred to the workings of the invisible hand of market forces. The development of energy markets in Texas is a clear example of the very visible hand of government intervention, though it may be equally blind.

CCS for gas-fired plants

The path to reach the NOAK level of costs for gas plants should be less expensive than for coal plants, but the technology is at least 5–10 years less mature. A pilot project planned for Statoil's Mongstad CHP plant at a refinery near to Bergen in Norway was cancelled in 2013 after its projected costs were reported as having quintupled in five years. Statoil and the Norwegian government concluded that the costs and risks of the project had been greatly underestimated in the original plan. Up to now, about \$1.4 billion has been spent at the test facility at Mongstad, which handles a small proportion of the emissions from the CHP unit and the catalytic cracker at the refinery.

Earlier in 2013 the Alberta government cancelled its support for a carbon capture project planned for the Swan Hills 340 MW coal-to-gas plant, because the low level of gas prices undermined the viability of the coal gasification process.

Most recently, late in 2015, the UK cancelled its funding for the CCS competition for which retrofitting the Peterhead gas plant, with a planned capacity of 385 MW, was one of the prime bidders. It appears that the project sponsors have lost confidence that the benefits of demonstration projects implemented at a commercial scale, including any learning, will outweigh the costs incurred.

The future of projects relying on revenues from the use of CO_2 for enhanced oil recovery is particularly uncertain, because low oil prices have reduced their prospective return and have led to a squeeze on investment budgets. It is very unlikely that any commercial-scale projects for carbon capture at gas power plants will be in operation significantly before 2025 given the delays in construction that have dogged similar projects at coal power plants.

Notes

27. Reports on the parasitic power consumption of the demonstration plant are inconsistent. The original unit had a net capacity of 139 MW, while the retrofitted and repowered unit has a net output of 110 MW. However, it appears that the repowering involved the installation of a 160 MW turbine and generator, in which case the effective parasitic power consumption is about 30%. This is in line with estimates for small scale plants reported by Rubin et al.
28. The cost per tCO_2 avoided depends upon how the low availability of the carbon capture plant has affected parasitic power consumption and other operating costs. The information available suggests that the capital cost per tCO_2 is at least 12 times the equivalent NOAK value. It is unlikely that the abatement cost for current operation of the plant is less than \$500 per tCO_2.
29. See Appendix E.
30. The ERCOT system is becoming more difficult to manage because wind generation tends to peak at night and during seasons with relatively low loads while wind generation is concentrated in areas far from the main load centres. The situation is exacerbated by the absence of any significant interconnection with other regional systems. As a consequence, it requires huge amounts of thermal backup capacity that will operate with load factors of less than 10%. The variable operating costs of a coal plant with CCS are significantly higher than the equivalent costs for a gas CCGT, so either a CO_2 offtake agreement or a dispatch guarantee is required to enable such a plant to compete at mid merit with gas plants.

Appendix E: Components of the cost of carbon capture for coal

Capital costs

A key component of CCS cost estimates is the scale of the capital investment required to construct the CO_2 capture plant. This is referred to as the 'overnight capital cost', which strips out the effect of the time required to plan and build the plant (interest during construction). The representative cost (converted to US dollars at 2015 prices) for post-combustion capture at supercritical coal plants[31] is estimated to be about $2,700 per kW of net capacity, which is 50% higher than was estimated 10 years earlier.[32] The cost of a new supercritical coal plant including carbon capture is estimated to be $4,800 per kW of net capacity. Rubin et al. do not provide estimates for subcritical coal plants, which comprise the majority of plants in operation in China, but other studies suggest that the cost of retrofitting such plants is likely to be at least 20% higher.[33] If FGD (SO_2 removal) and SCR (NOx removal) units have to be added as part of the retrofit, the overnight capital cost of carbon capture will be increased by at least $500 per kW of capacity. These are all NOAK estimates, so early projects are likely to involve much higher capital costs.

Even on an NOAK basis, the capital cost of retrofitting an existing Chinese subcritical coal plant without emission controls will be nearly two-thirds the capital cost of building a new supercritical coal plant with integrated carbon capture. Since the latter should operate with a much higher thermal efficiency[34] – and a higher load factor – it is extremely unlikely that the Chinese government would be inclined to force coal generators to retrofit existing subcritical plants with carbon capture. This conclusion, by itself, means that less than 240 GW out of China's expected 2020 level of 980 GW of coal capacity might be considered as suitable for retrofits, while the remaining 740 GW of coal plants will operate unabated throughout their operating life.

Current estimates suggest that the capital cost of adding pre-combustion carbon capture to coal IGCC plants may be only $1,200 per kW with a total capital cost per kW that is similar to that for supercritical coal plants with post-combustion capture. However, experience with coal IGCC is very limited and far from convincing.

Capture rate

This is measured as the reduction in average CO_2 per MWh. For new supercritical coal plants the capture rate is expected to be 87%, a little higher than the estimate of 85% made in 2005. The capture rate tends to increase with plant size, but the gap between capture rates for small and large plants has closed over the last decade. The capture rate for IGCC plants is expected to be 86%, again lower for small plants than for large ones.

Parasitic consumption

This is the proportion of energy input that is used to run the carbon capture unit. Most of this energy is consumed in regenerating the solvent/sorbent used to remove the CO_2. It is measured as the reduction in the thermal efficiency for plant fitted with carbon capture relative to reference plant without carbon capital. The typical level of parasitic consumption is estimated as 23% for post-combustion capture and 20% for pre-combustion capture in an IGCC. Parasitic consumption tends to be higher for small plants than for larger plants, especially for post-combustion capture: 30% for a supercritical plant of 500 MW but 18% for a similar plant of 1000 MW. Future development in alternative technologies may reduce the economies of scale, but in the immediate future it is unlikely that either generators or consumers will be willing to accept the cost of operating carbon capture units for small or medium sized coal plants.

Operating and maintenance costs

Most studies provide limited information on their assumptions about O&M costs excluding fuel use. However, estimates prepared for the EIA's *Annual Energy Outlook* imply that recurrent costs are equivalent to at least \$12 per MWh for supercritical coal plants operating with a load factor of 60% and about \$3 per MWh for coal IGCC plants.

Notes

31. The descriptors 'supercritical' and 'subcritical' refer to the operating pressure of the steam generator. Supercritical plants are capable of significantly higher thermal efficiency than subcritical plants but they are relatively expensive to build and much harder to operate reliably. Subcritical coal plants account for about 75% of coal generating capacity in China and are relatively young with a median age of less than 10 years in 2015 – see Caldecott et al. (2017). Many of these plants are not equipped with FGD units, so that the costs of any retrofit would have to include the installation of controls to meet more stringent standards for the removal of SO2, NOx and particulates.
32. Rubin et al. comment that 'These increases... may in part be due to a greater understanding of the requirements and design of modern reference plants and large scale capture plants' (p. 383). They note, in addition, that the increase in costs for pre-combustion capture has been even larger than for post-combustion capture. This pattern – and practical experience – suggests that actual FOAK costs may turn out to be substantially higher than the estimates that have been built into learning cost models for carbon capture.
33. IEAGHG (2011).
34. 40–44% vs 33–35% on a higher heating value (HHV) basis.

Appendix F: Assessing CCS for different load factors

In this appendix I will illustrate the impact of load factors on the viability of carbon capture. I will consider two scenarios for the reference power plant generating a net output of 800MW. In Scenario A the plant is expected to operate on baseload for 20 years with a load factor of 85%, while in Scenario B it is expected to operate with a load factor of 60% over this period. The real pre-tax cost of capital is assumed to be 8% for all NOAK cost estimates.[35] I assume that the wholesale market price in the long term would be set by gas CCGTs with CCS. For the initial period of 20 years, any new capacity, other than gas without CCS, would require some form of support via either capacity payments or guaranteed prices (via CfDs or FITs). A carbon price, even of \$100 per tCO_2, would not provide sufficient support because CO_2 emission from gas CCGTs with CCS would be minimal.

Scenario A

The overnight capital cost of a supercritical coal plant would be approximately \$2.2 billion and would emit 4.7 $MtCO_2$ per year. Building an IGCC plant without carbon capture would cost \$2.67 billion and would reduce emissions by 0.07 $MtCO_2$ per year. Operating costs would be about \$4.3 per MWh higher for the IGCC, so the MAC of the reduction in CO_2 emissions by choosing an IGCC in preference to a supercritical coal plant would exceed \$1,000 per tCO_2. In contrast, the present value of the saving made building a gas CCGT with an overnight capital cost of about \$0.9 billion rather than a coal plant would be nearly \$0.7 billion, so the reduction in CO_2 emissions of about 2.55 $MtCO_2$ per year from this switch comes at zero cost. This illustrates why any analysis of the MACs for the power sector in Europe and North America must start from the assumption that the baseline is reliance upon gas CCGTs.

Starting with this baseline, a supercritical coal plant with CCS would incur additional capital and O&M costs equivalent to about \$405 million per year and would reduce CO_2 emissions by 1.53 $MtCO_2$ per year, a MAC of over \$260 per tCO_2. The equivalent figures for choosing a gas CCGT with CCS would be an annualised cost of \$225 million per year and a reduction in emissions of 1.91 $MtCO_2$ per year with a MAC of \$117 per tCO_2. This exceeds the upper threshold of \$100 per tCO_2 that I consider reasonable, but not by a large amount. These figures are based on a gas price of about \$6.5 per million BTU, which is high for the US but may be regarded as reasonable for Europe.

If both coal and gas prices were 50% higher, the cost difference between a coal plant without CCS and a gas plant without CCS would be much smaller but would remain marginally in favour of gas. However, the absolute and relative differentials between the MACs of installing CCS at coal and gas plants would increase, even though the MAC for gas CCS would increase to \$145 per tCO_2.With a carbon price of \$50 per

tCO_2, the advantage of gas over coal is substantially increased, as would be expected. The MACs for coal or gas with CCS are not affected but the total is split between the carbon tax and additional support required to underwrite the cost of building and operating CCS.

Scenario B

The key difference in this scenario is that the fixed costs of investment in both plant and CCS have to be spread over a smaller number of operating hours and, thus, over a lower reduction in CO_2 emissions. Naturally, coal plants are even less economic relative to gas and the MAC for coal with CCS relative to a gas CCGT is close to \$350 per tCO_2. More important, the MAC for installing CCS at a gas CCGT increases to \$137 per tCO_2 and would increase further if the expected load factor during the first 20 years of operation were lower than 60%.

In summary, these scenarios reinforce the analysis in the main text. Carbon capture for coal plants is an extremely expensive method of reducing CO_2 emissions in both mature and emerging economies, even if large resources were committed to underwrite the initial program of investment required to bring down the costs of carbon capture to the NOAK levels examined here. The consequence is that the return on this kind of investment in learning would be low or negative. Public money – or electricity consumers' money – should not be wasted in this way.

Notes

35. As an illustration of the bias that is built into official UK estimates of generating costs, the most recent set of generation cost estimates published by BEIS assumes pre-tax hurdle rates of 6.5% for solar, 6.7% for onshore wind, 7.8% for gas CCGT and OGCT, 9.3% for coal CCS and as high as 22% for geothermal. In part this reflects lower effective tax rates – 11% or 12% vs 20% – for renewables. The difference has little impact on generation technologies, such as gas, with low capital costs but it highlights a systemic failure to carry out a proper economic analysis of alternative technologies. Similar biases are present in comparisons carried out for the US by the EIA, especially with respect to the role of production tax credits.

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