International Energy Agency

THE ECONOMICS OF TRANSITION IN THE POWER SECTOR

INFORMATION PAPER

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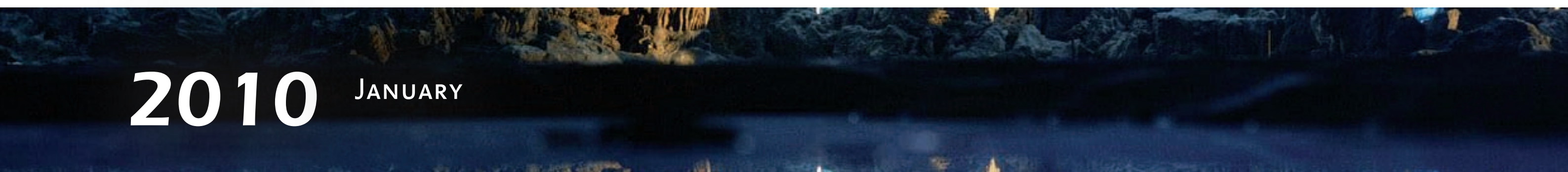

2010 January

INTERNATIONAL ENERGY AGENCY

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This paper was prepared for the IEA Climate Change Unit in 2009. It was drafted by William Blyth, Oxford Energy Associates. This paper reflects the views of the IEA Secretariat and may not necessarily reflect the views of the individual IEA member countries. For further information on this document, please contact Richard Baron, Climate Change Unit at: richard.baron@iea.org

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1. Introduction – Global context

Power generation from fossil fuel is one of the largest sources of greenhouse gas emissions, representing 41% of global energy-related CO_2 emissions. Combined with the fact that there are a number of low-carbon technologies available for generating electricity, the sector is therefore a key policy target for delivering near-term and long-term reductions in emissions. Compared to the reference scenario, the WEO scenarios for meeting carbon constraints involve a significant reduction in the power sector's share of total CO_2 emissions. This share for the OECD countries is projected to decline from its current level of 40% to a level of 32% for the 550ppm scenario and 25% for the 450ppm scenario in 2030.[1]

This means that the power sector carries a considerably greater burden of the required emission reductions than other sectors, a feature common to many scenarios of emissions abatement. The scenarios rely on a significant shift away from unabated coal, towards greater use of carbon capture and storage, nuclear and renewable technologies combined with significantly improved end-use of electricity. These reductions will only be possible if existing plants are replaced with more efficient and less-emitting types of plants over this timescale.

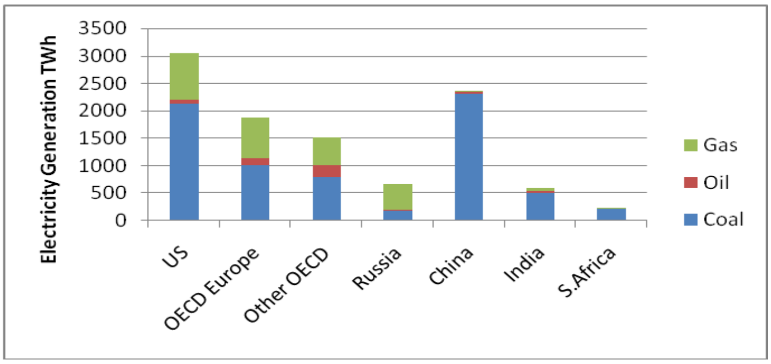
The economics of this transition are often modelled from a macro-economic perspective based on estimates of the cost differences between the types of plants assumed in the different scenarios. For example, the WEO 550ppm scenario implies an increase in investment in the power sector over the period 2010-2030 to USD 7.3 trillion compared to USD 6.1 trillion in the reference scenario, despite a reduction in electricity demand of about 5% in the 550ppm scenario. Electricity prices are assumed to rise to provide an appropriate level of return to incentivise these additional investments.

However, the micro-economics of these investments can also be important, and can give additional insights into the potential costs and incentives required to stimulate a shift in investment patterns. Micro-economic analysis is suited to incorporating questions of risk, and the additional return on investment that companies require when they need to make investment decisions under uncertainty. A period of transition is by definition one where the system is being perturbed away from the equilibrium investment conditions typically assumed in macro-economic analyses. Incorporation of risk typically causes companies to increase the return they require on investment. This means that the incentive mechanisms (*e.g.* increases in electricity prices or price signals provided by climate policies) required to stimulate the transition to a low-carbon system may need to be stronger than are implied by an equilibrium macro-economic analysis.

This report identifies the importance of these risk factors in the economics of transition by illustrating the case of investment in the power sector. To a great extent, the transition to a low-carbon power sector means dealing with coal plants, which is the largest contributor, accounting for 73% of global power sector CO_2 emissions, and particularly those from the United States, Europe and China, which contribute 17%, 9% and 24% respectively of global power sector CO_2 emissions. Power generation by type of fossil fuel for different countries are shown in Figure 1.

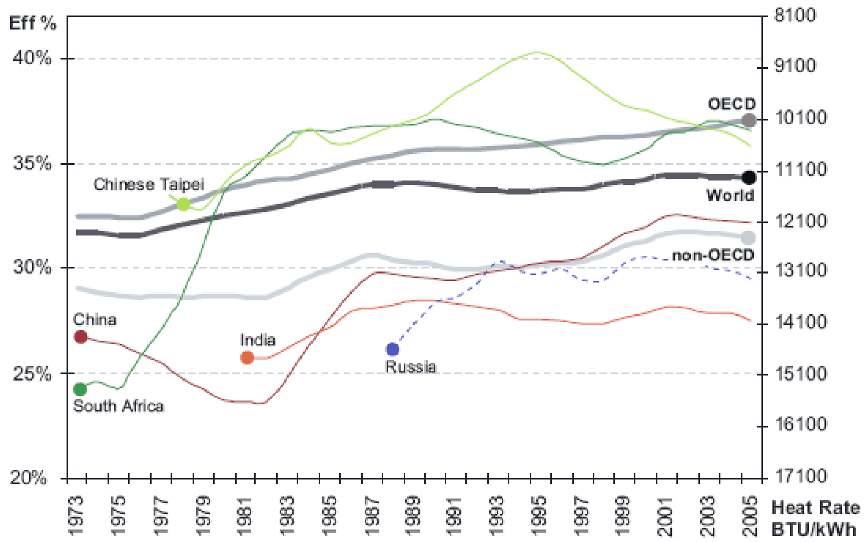
[1] International Energy Agency (2008), *World Energy Outlook 2008*, Paris.

Figure 1. Power generation from fossil fuels 2006[2]



Average plant efficiencies across the world have increased steadily over the past 30 years, with efficiencies for non-OECD countries lagging around 5 percentage points lower than OECD countries (Figure 2). Bringing these efficiencies into line with best available technologies would lead to an emission saving of around 8% of global totals.[3]

Figure 2. Electric efficiency of coal generators[4]



Upgrading coal plants on this scale is a complex task that needs to take into account various local factors that could act as technical constraints or influence investment conditions. An important factor to take into account will be the natural investment cycles in the power sector. Major investments in upgrading or replacing power generation plants with more efficient equipment will be most cost-effective when these plants are due for refurbishment or replacement due to their age.

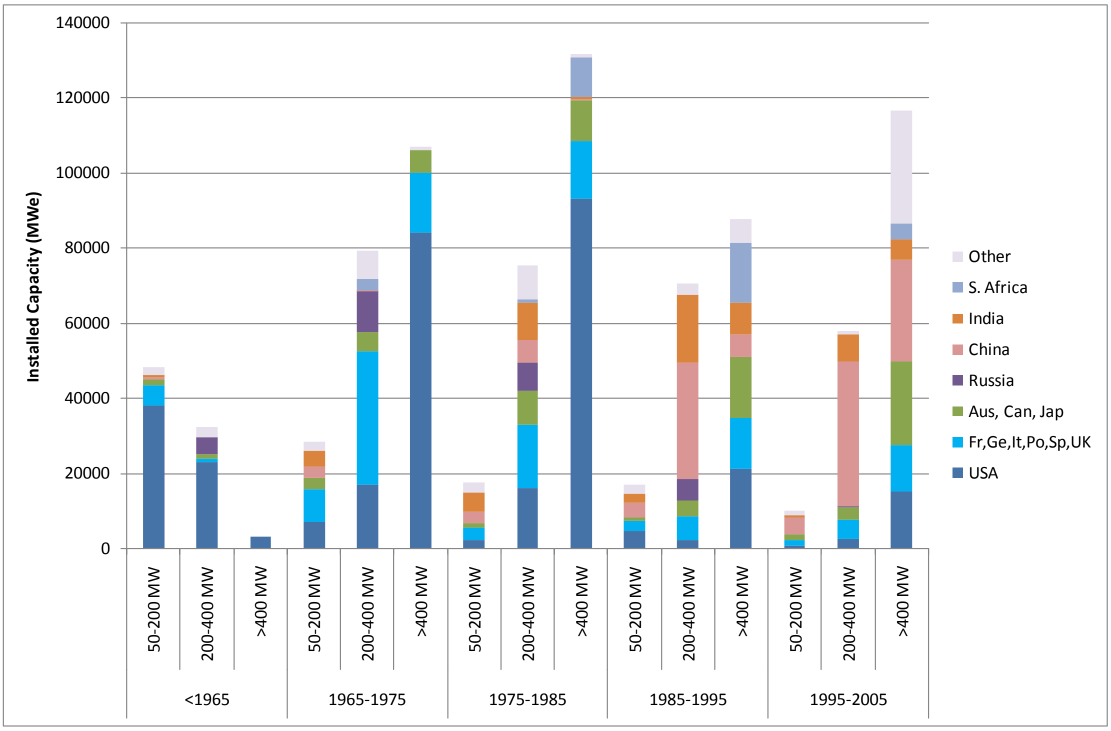
[2] International Energy Agency (2008), *Electricity Information*, Paris.

[3] *Ibid.*

[4] N. Maruyama and M. Eckelman (2009), "Long-term Trends of Electric Efficiencies in Electricity Generation in Developing Countries", *Energy Policy Article*, in press.

Plant replacement cycles are therefore an important factor in determining how quickly more efficient plants can diffuse into the sector. In practice, plant turnover rates can be very slow in the power sector. Figure 3 shows the age distribution of coal-fired plants in selected countries.

Figure 3. Vintage profile of currently installed coal-fired power plants in selected countries[5]



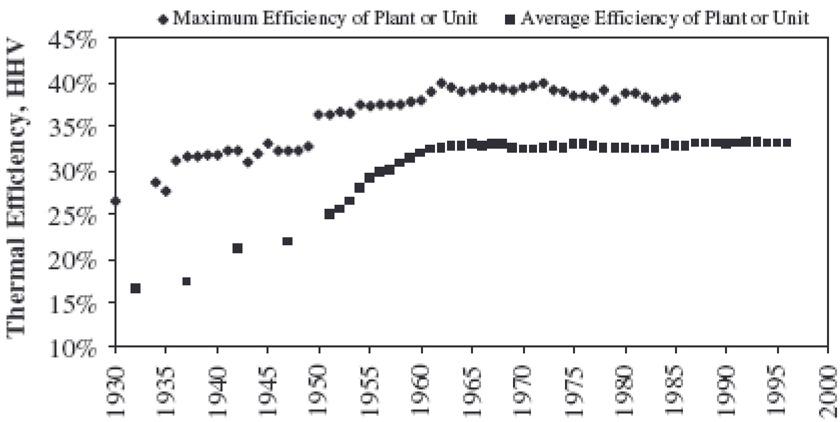
Broadly speaking, old plants are largely located in Europe and the United States. There is still a considerable amount of aged coal-fired generation capacity built before 1975 in Europe (particularly in the United Kingdom and Germany), and the United States accounts for over half of all plants that are more than 30 years old. The question of plant replacement and refurbishment therefore is particularly relevant to these regions. Given the good availability of data for plants, the United States makes an interesting case study, presented in the next section.

[5] Derived from IEA Clean Coal Centre (2005), "Life Extension of Coal-fired Power Plant".

2. US coal case study

Whilst the efficiency of coal plants globally has been increasing over the past 30 years, this trend has not been apparent in the United States. Figure 4 indicates that average efficiencies have been static for the past 30 years, and are as much as 7 percentage points lower than in some other OECD countries.

Figure 4. Efficiency trends in US coal-fired power plants[6]



This stagnation in efficiency levels is largely due to the age profile, since much of the capacity in the United States was installed during the 1960s and 1970s, and retirement levels have been very low. Figure 5 shows that the plant vintage (*i.e.* the year of initial operation) of US capacity has remained almost unchanged since 1985. Clearly, much of this capacity has been significantly uprated and refurbished, but efficiency levels are still often constrained by overall design characteristics.

The economics of plant replacement depend on many factors. In the United States during the 1970s, capital and operating costs for coal-fired plants increased significantly due to the additional environmental constraints on sulphur, particulates and water use and discharge. Joskow (1987) provides an in-depth review of the economics and performance characteristics of plants installed over this period, showing that unit costs rose during this period, having previously declined as a result of technological improvements and economies of scale.

These plant economics have persisted for long time. Ellerman[7] reports EIA figures from 1994 showing that financially, life extension of existing plants significantly outperformed investment in new plants (both coal and gas).

[6] S. Yeh and E. Rubin (2007), "A Centurial History of Technological Change and Learning Curves for Pulverized Coal-fired Utility Boilers", *Energy* ***32***, pp. 1996-2005.

[7] EIA data. Data for 1994 and 1985 are taken from figures reported in D. Ellerman (1996), "The Competition between Coal and Natural Gas", *Resources Policy*, 22 1/2, pp. 33-42.

Figure 5. Plant vintages of US plants at 3 different points in time[8]

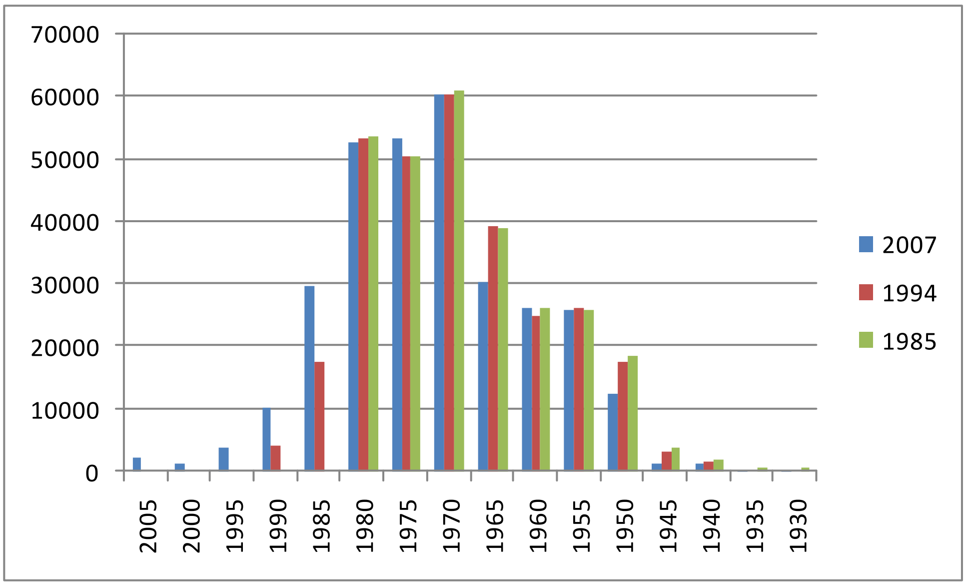
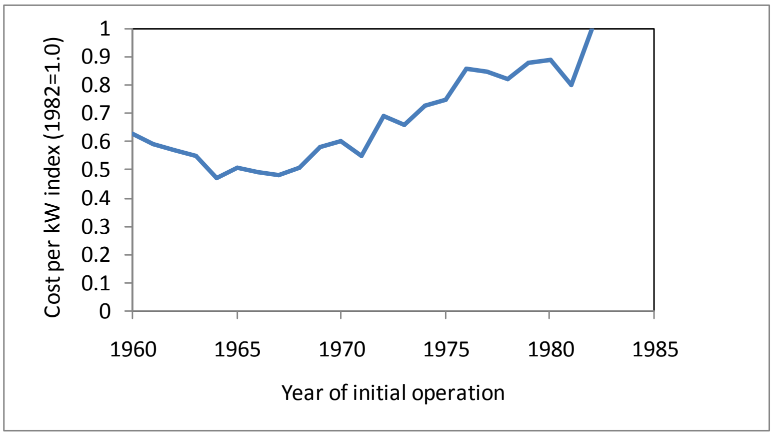


Figure 6. Index of construction costs during the 1960s and 1970s



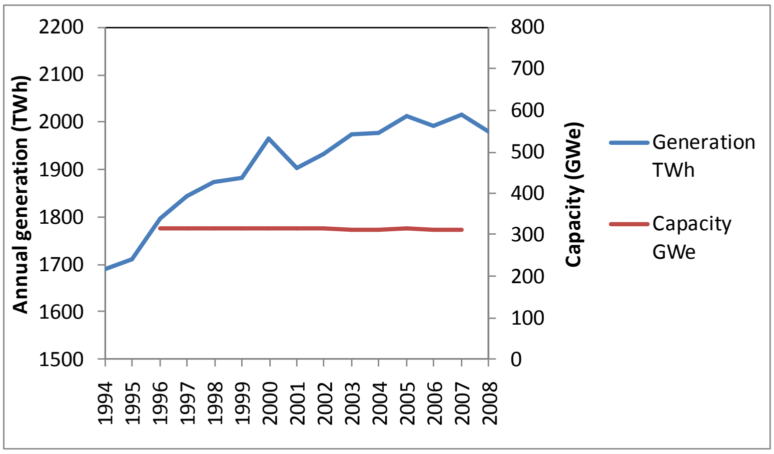
[8] *Ibid.*

Table 1. Economics of plant replacement vs. life extension (data from 1994)[9]

US cents/kWh	New coal plants	New CCGT	Existing plants full life extension
Capital	3.53	1.42	0.61
Fixed O&M	0.49	0.13	0.28
Var O&M	0.67	0.21	0.17
Fuel cost	1.26	1.83	1.30
TOTAL	5.94	3.60	2.36

Although these data are now quite old, the pattern has persisted up to the current period. In fact, not only are coal plants being extended rather than replaced, but this existing coal-fired capacity is being used ever more intensively since the Ellerman paper. Figure 7 shows the increase in annual generation from coal plants (17% since 1994), whilst capacity has remained almost unchanged over this period.

Figure 7. Trends in coal-fired capacity and generation



Much of this economic picture is tied up with the issue of environmental regulation. The typical replacement cycle whereby old plants are replaced when their operating costs exceed the total long-run marginal cost of a new plant has not occurred in the United States, largely because old (existing) plants are run to a lower environmental standard than new plants. The New Source Review (NSR) programme of the Clean Air Act sets environmental standards for stationary sources covering both new plants and major modifications of existing sources.

A crucial factor has been the interpretation of "major modification" in the context of this regulation. Many of the plants built in the 1960s and 1970s have undergone considerable uprating, upgrading

[9] *Ibid*.

and refurbishment since the early 1990s. The question of whether such changes required the plants to meet the more stringent standards turns out to be a deciding factor in the economics. At the time, many operators assumed that old coal plants would be phased out as a result of the NSR requirements because the cost of fitting best practice SO_x and NO_x controls would be prohibitive for older less efficient plants. However, in practice so far, operators and regulators have interpreted most of the refurbishments that have taken place as not requiring them to meet best available control technology for the pollutants covered in the NSR programme. This has allowed the existing plants to continue (and even increase) operations over the past 10-15 years.

3. Plant refurbishment options

A thorough description of refurbishment options available for existing coal plants is available in the literature, for example the IEA Clean Coal Centre[10] and Boncimino.[11] Typically, good maintenance regimes, cleaning, and control of coal quality and water treatment can help to keep existing plants running longer, but build-up of scale on the water-side of boiler tubes can severely restrict heat transfer rates, lowering efficiency and causing problems on start-up due to overheating which reduces plant flexibility. The end of useful service life of the high-temperature components in a boiler is usually a failure by a creep or stress-rupture mechanism, sometimes accelerated by corrosion or erosion effects from fly-ash that reduce the wall thickness and limit the lifetime of boilers. Eventually, maintaining the existing plants will no longer be possible, and upgrading or refurbishment will be required. Examples of upgrading power plants to extend their life and improve performance include:

- **Instrumentation and data analysis upgrades**. Data analysis systems often have a much shorter lifetime (10-15 years) than the plants they are applied to. Upgrading these systems can help improve operating flexibility, reduce maintenance costs, reduce emissions and extend plant life.
- **Air heaters.** Air heaters heat combustion air and cool boiler exit flue gas. Boiler efficiency is improved and the hot air needed for drying coal and obtaining proper combustion is provided to the pulverisers and burners. Air heater operating deficiencies include excessive leakage of combustion air into the boiler exit flue gas flow, low air temperatures to the pulverisers and burners, excessive air and flue gas pressure loss. As a result of these conditions, boiler efficiencies can decrease in the range of 0.2% to 1.5%. These deficiencies can be corrected by air heater improved surface cleaning, air to gas path seal improvements, and other upgrading and refurbishment.
- **Pulverisers**. The performance of coal pulverisers can be important in determining the flexibility of a plant to use different types of coal. For example lower sulphur coals may be required to meet environmental standards, or lower calorific value coals may be preferred to reduce costs, but these would require a greater mass flow rate in order to provide the same heat input to the boiler. In an older plant, the pulveriser capacity may have diminished, affecting the full load capability of the power plant, and operating and maintenance costs may have increased. Control of the coal fineness (depending on boiler firing conditions and the nature of the coal) is essential for minimising NO_x formation and maximising carbon burnout. In some circumstances, depending on the level of volatile matter in the coal, inert gases may need to be introduced to the milling process to reduce oxygen content and prevent self-ignition. Control of coal and air distribution systems (particularly achieving balanced flow of air and coal into multiple burners) can be a long-winded manual process, but automated systems hold the potential to improve performance, especially after low-NO_x burners have be installed. Improved and refurbished pulverisers often reduce unburned carbon, which is wasted fuel. Fly ash carbon content in

[10] R.M. Ambrosini (2005), "Life Extension of Coal-fired Power Plants", *IEA Clean Coal Centre Report CCC/106*.
[11] G. Boncimino, W. Stenzel and I. Torrens (2005), "Costs and Effectiveness of Upgrading and Refurbishing Older Coal-fired Power Plants in Developing APEC Economies", *APEC Energy Working Group Expert Group on Clean Fossil Energy Project EWG 04/2003T*.

the range from 1% to over 30% has been encountered. A 30% carbon content causes a loss of boiler efficiency between 0.2% to 0.5% (Boncimino, 2005).

- **Boiler upgrades**. Improvements to boilers can include upgrading the burners (for example to low-NO_x burners to meet environmental standards), and improving the sootblowers for the cleaning of fireside components of the boiler to improve heat transfer and efficiency levels.
- **Steam turbines**. Refurbishments include removing deposits that cause a reduction in blade aerodynamic performance, repairing or replacing the first stage turbine blades that have been damaged by boiler tube scale, and replacing or adjusting blade and shaft seals. Major performance improvements can be implemented on many turbines with newer, more efficient turbine blades and other components. These improvements are possible because current turbine designs perform more efficiently than the designs that were available ten to twenty years ago.
- **Condensers**. Scaling on the water-side of the condenser tubes decreases the heat transfer coefficient and results in higher condenser pressures. Increased condenser pressure will significantly reduce steam turbine output and efficiency. Cleaning the condenser tubes can reverse some of this performance deterioration.

In addition to these upgrade options which keep the basic plant configuration unchanged, it is possible, at least in principle, to carry out more significant conversions of existing power plants to bring them closer to state-of-the-art technology. The feasibility of converting existing subcritical plants to supercritical plants has been studied, although no actual projects to carry out such a conversion have yet been undertaken. More common are fuel switching projects (case studies are presented in the IEA CCC report for example to convert from oil to coal firing in Italy and Japan), or conversion to a new technology configuration (*e.g.* to fluidised bed boilers in Poland, and integrated gasification technology in the United States). These major plant conversion projects relate less to extension of existing plant life, being closer to complete plant replacement projects, but with some economic savings due to keeping some of the existing ancillary plant operational.

Data on the costs of these refurbishment options are not widely reported, partly because they can be very site-specific, and partly because of commercial sensitivity of the data. Where projects have been carried out, economic analysis tends to focus on the net costs, which are often reported as being negative, *i.e.* showing net benefits to refurbishment projects. Boncimino reports capital costs for three case studies: improvements to air heating systems having capital costs of less than USD 1.5m, steam turbine replacements with capital costs of less than USD 5m, and the cleaning of condenser tubes with overall costs of around USD 50k. Cost data on more significant upgrades (but without technical details) are also included in the report involving capital costs of between USD 150m-172m, with NPVs of between -USD 65m to + USD 77m. The negative NPV projects refer to brown coal plants which have lower fuel costs and involve higher capital costs. The projects result in emission reductions of between 2%-3.4%. The report concludes that 50% of the APEC[12] region coal-fired power plants would be able to achieve a 3.5-percentage point CO_2 reduction at a negative or zero net cost.

These data correlate with EIA data reported by Ellerman[13] which shows capital costs of USD 127m for full life extension of gas-fired steam turbines and USD 244m for full life extension of existing coal plants. A definition of full life extension is not provided in the paper, but probably includes repowering the existing plants to significantly boost output levels and extend the lifetime by at least

[12] Asia-Pacific Economic Cooperation, a group of 21 member economies in the Asia-Pacific region.
[13] D. Ellerman (1996), "The Competition between Coal and Natural Gas", *Resources Policy,* 22 1/2, pp. 33-42.

10-15 years. These data are now rather old (reported in 1994); adjusting for inflation would bring the costs up to the region of USD 350m, and probably higher given the disproportionate rise in capital cost of equipment over this period. The interesting point in those reported data is that re-powering existing plants in this way is cheaper than new plants, as reported by Ellerman, although the comparison of costs is complicated by assumptions about the required environmental performance of existing compared to new plants as discussed in the previous section.

Another data point on capital costs is provided by reports in 2007 of refurbishments at the Drax coal-fired plant in the United Kingdom, which includes expenditure of GBP 100m over 5 years on new turbine blades, expected to boost the average efficiency from 38% to 40%, and cutting emissions by $1MtCO_2$ per year.[14]

In summary, the extent of the refurbishment required and corresponding costs required to extend plant life will depend on many factors including the current condition of the existing plants, the duration of the extension required, the need to increase power output, and the environmental standards required from the refurbished plants. Project capital costs in the literature are reported in the range <USD 1m to USD 244m depending on the scope of these changes. These projects are often reported as having a positive overall NPV, although there may be some selection bias in the choice of case studies. Even taking into account just the capital costs gives some basis for comparison with the option values that are investigated in the following section, which often are significantly higher than the capital costs reportedly required for extending plant life.

[14] Reported in the *Financial Times*, 9 March 2007.

4. Micro-economics of refurbish vs. replace decisions

4.1. The need for a micro-economic perspective

In simple economic theory, firms would choose to replace existing plants when the short-run marginal operating costs of these plants exceed the long-run marginal cost of a new plant. This might be expected to occur if the plant efficiency has deteriorated due to age, or if new plant costs have dropped due to technological improvements or economies of scale. In the power sector, the situation is a bit more complex because older plants are often shifted lower down the dispatch order, so that they operate for less and less time as they age, rather than retiring outright. Nevertheless, equilibrium economics would suggest such decisions being made purely on the basis of marginal cost of the different options, evaluated at any particular point in time. Since the costs being considered arise in the future and are therefore uncertain, the analysis would be done on the basis of expected values – *i.e.* based on the average of some estimated probability distribution of future values for the key parameters such as prices, capital costs, etc.

In practice there are several factors that can reduce the rate of uptake of new technologies, leading to a gap between the most energy-efficient technologies available at some point in time and those actually in use.[15] As discussed in Section 2, the US example shows that environmental regulations can alter the economics of plant replacement vs. life extension of existing plants leading to extremely low plant turnover rates. But even in the absence of regulatory bias, there can be incentives to continue with existing plants rather than replacing with best available new technologies. These include:

- The combination of uncertainty regarding investment decisions, the possibility of learning in the future which resolves some of this uncertainty, and some degree of irreversibility in the investment decision creates an option value for waiting, which encourages continued use of existing plants;[16]
- The performance of new technology may be expected to improve over time (or risks reduce over time) due to technological spillovers of R&D and learning-by-doing by rival firms, creating an incentive not to be first-mover;[17]
- Companies may have a vested interest in particular technology types that are engrained in the industrial structure of the country in which they operate, which distorts their incentives to invest in best available technology;[18]
- Companies may benefit from maintaining diversity in the mix of technologies they use for generation, which together with other strategic objectives can override the economics of individual plant choice.[19]

[15] A.B. Jaffe and R.N. Stavins (1994), "The Energy Paradox and the Diffusion of Conservation Technology", *Resource and Energy Economics*, 16, pp. 91-122

[16] A. Dixit and R.S. Pindyck (1994), "Investment Under Uncertainty", Princeton University Press, Princeton, NY.

[17] International Energy Agency (2000), *Experience Curves for Energy Technology Policy*, Paris.

[18] P. Krusell and J.-V́. Ríos-Rull (1996), "Vested Interest in a Positive Theory of Stagnation and Growth", *Review of Economic Studies*, 63, pp. 301-329.

[19] P. Mulder, H.L.F. de Groot and M.W. Hofkes (2003), "Explaining Slow Diffusion of Energy-saving Technologies", *Resource and Energy Economics*, 25, pp. 105-126.

These factors all represent dynamic effects where decisions made by the company are based on factors other than the basic financial criteria of achieving a positive net present value (NPV). Companies will generally optimise their decisions on the basis of a number of factors that are left out of the normal NPV calculation. Such factors include optimising the timing of investment with respect to resolution of uncertainty, optimising performance of their broader portfolios, or optimising on the basis of broader strategic goals, market dynamics or supply chain dynamics. It is the presence of these dynamic factors, and the ability of companies to optimise decisions through exercise of management flexibility and strategy, that explains why behaviour in the real world often deviates from that assumed in macro-economic analyses which generally assume that companies aim to maximise NPV based on snapshot current estimates.

Different approaches can be used depending on which aspect of the decision-making process is being focussed on. For example, mean-variance portfolio theory is often used to look at the value of diversity in the generation mix.[20] This approach can be useful in understanding the system-wide benefits of diversity which are not necessarily captured in an individual plant level NPV analysis, and can lead to policy conclusions regarding the need to provide additional incentives to promote such diversity. Another approach,[21] and the one explored in this report, uses real options analysis to look how the presence of risk and the evolution of investment conditions over time mean that incentives need to exceed the standard positive NPV rule implied by equilibrium economics in order to deliver investment. This is useful when considering the increased stringency that may be required in regulatory frameworks for inducing a low-carbon transition compared to expectations formed by macro-economic models.

Although the current report focuses on the risk aspect of decision-making, one of the general message to take is that micro-economic analysis can lead to important insights and policy conclusions that are supplementary to those arising from broader macro-economic analyses. The type of micro-economic analysis required will depend on the particular application or policy question being considered, and real options analysis will not always be the most appropriate. However, the aim here is to show in some detail how a micro-economics perspective can capture some of these dynamics in order to provide an illustration of the types of policy insight that can arise when a closer look is taken at decision making.

4.2. The option value of waiting

This paper explores a particular feature of the micro-economics of investment; namely, the value of waiting that arises from uncertain future prices. A previous publication by the IEA presented quantitative analysis of option values in the face of uncertainty in climate policy and energy prices.[22] That work showed that under some circumstances, climate policy uncertainty could add an appreciable risk premium to the investment case for new power plants. This was particularly the case when carbon price was a significant driver of the investment case (*e.g.* for low-carbon technologies such as carbon capture and storage and nuclear power), whereas policy uncertainty was less of an issue in cases where the technology choice was driven more strongly by fuel and electricity price expectations.

[20] See *e.g.* M. Bazilian and F. Roques (2008), “Analytical Approaches to Quantify and Value Fuel mix Diversity”, in *Analytical Methods for Energy Diversity & Security*, Eds Bazilian & Roques, Elsevier, Oxford.
[21] Blyth (2008), “Use of Real Options as a Policy-analysis Tool”, in *Analytical Methods for Energy Diversity & Security*, Eds Bazilian & Roques, Elsevier, Oxford.
[22] International Energy Agency (2007), “Climate Policy Uncertainty and Investment Risk”, Paris.

In this work, we extend these ideas to look more specifically at the way in which plant-life extension of existing plants can enable companies to realise the option value of waiting by allowing them to maintain their market share by supplying electricity from existing plants, and deferring building of new plants. As described in the IEA publication, the value of this flexibility to defer investment can be quite substantial if, by waiting, companies can learn something about future prices and investment conditions. This potential for learning can allow companies to make a more optimal investment choice in the future than they are able to do immediately, and this creates the option value of waiting.

In principle, companies could invest in their existing plants up to this option value, and still be maximising their expected net present value. As discussed below, these option values are often significantly greater than the amounts required to keep plants running, leading to a financial hurdle rate that new plant economics must exceed if they are to enter the market in a situation of uncertainty.

The model developed here is a simplified decision-tree analysis of the key uncertainty factors affecting the technology choice for power sector investment. The choices available in the model include unabated coal, coal + carbon capture and storage, gas and nuclear. Renewable technologies were excluded from the analysis because investment is currently driven by separate policy mechanisms, so they do not respond to the same price drivers, and would not be cost-effective under the carbon price scenarios considered in this analysis. In the longer term, one would expect convergence between the price signals created by renewables policies and the signals created by carbon markets, so that all investment options would be considered on a "level playing field". Methodologically, inclusion of renewables in this kind of analysis would be straightforward.

The tree separates out six scenario parameters to represent key uncertainties in the cash-flow parameters:

- Electricity price.
- Carbon price.
- Capital costs (general).
- Capital costs (nuclear).
- Gas price.
- Coal price.

For each of these parameters, a high and a low scenario is defined. An investor taking a decision immediately estimates their expected NPV based on a best guess about the future. This guess is taken to be a mid-point between these two scenarios, but the investor faces uncertainty about which of these scenarios will be realised. An investor that can wait receives additional information about which scenario they are in.

These six variables generate 64 possible scenario combinations of prices and costs which affect the economics of the investment options being considered. The deviation between the high and low scenarios for each of the variables does not necessarily represent the full degree of price & cost uncertainty, but rather it represents the degree to which an investor can learn over the time period in question about likely future price regimes over the lifetime of the investment. In this paper, we take this period of waiting to be 5 years. The learning rate over this time may be lower than the full degree of price volatility – for example fossil fuel prices will still be uncertain in 5 years time, although one might expect to learn something about their likely future direction in the intervening period. In the case of capital costs, the degree of learning may be closer to the full resolution of uncertainty if for example companies can learn from the investments made by others during the intervening period.

In this report, we consider 4 different investment options; CCGT, coal, coal + CCS and nuclear. For each technology, the expected NPV is calculated for each of the 64 combinations of prices and costs, and the model then simply selects the highest NPV across the four investment options. The NPVs are calculated assuming the same plant size (1 000 MWe) for each type of plant. A typical result is shown in Figure 8.

Figure 8. NPV (EUR m) results for the 64 scenario combinations in the decision tree.

Decision Matrix

Elec Price	Carbon Price	General Capital	Gas price	High Nuclear Capital – Coal Price Hi	High Nuclear Capital – Coal Price Lo	Low Nuclear Capital – Coal Price Hi	Low Nuclear Capital – Coal Price Lo
Hi	Hi	Hi	Hi	503	494	1328	1319
			Lo	631	548	924	842
		Lo	Hi	683	781	1328	1319
			Lo	812	728	924	842
	Lo	Hi	Hi	542	646	977	977
			Lo	376	357	387	368
		Lo	Hi	856	960	977	977
			Lo	556	537	556	537
Lo	Hi	Hi	Hi	0	0	615	608
			Lo	0	0	285	218
		Lo	Hi	0	70	615	608
			Lo	165	97	285	218
	Lo	Hi	Hi	0	0	329	329
			Lo	0	0	0	0
		Lo	Hi	208	312	329	329
			Lo	9	0	9	0

Note: Blue cells represent a gas investment, orange nuclear, grey coal and lilac CCS. Cells with zero are scenarios where no investment is made as NPVs for all technologies are negative

The figures shown in the decision matrix in Figure 8 represent the individual project NPVs that would be achieved if the investment was made in the relevant technology after a delay of 5 years into the future (details of the assumptions used to calculate these NPVs are shown in the Appendix). The choice of technology is then assumed to be made with the benefit of hindsight about which of the 64 states of the world the investor is in. The NPVs are then discounted back to the current time period in order to allow comparison with investment decisions taken immediately. Because different technologies are taken up under different scenario combinations in the case where investment is delayed, this decision matrix represents a simple optimisation procedure.

In order to work out the option value of waiting, the overall expected NPV of this optimised decision in year 5 needs to be judged in advance in the current time period. This requires assessing *a priori* the likelihood of each of the 64 scenario combinations occurring. If the six price and cost variables are completely uncorrelated, then each of the 64 scenario combinations is equally likely. In this case, the expected NPV of the optimised decisions is simply the average of all 64 figures in the decision matrix. On the other hand, if the six price and cost variables are 100% correlated, then there are only two possible outcomes (all variables high, or all variables low), and the expected NPV is the average of the top-left value and the bottom-right value in the matrix. The reality will be somewhere in between, and a probability matrix can be generated based on *a priori* judgements about likely correlations.

A simple example helps to illustrate this process. For the decision matrix shown in Figure 8, assuming all variables are uncorrelated, the expected NPV is the average of those values shown in the table, equal to EUR 472m. This can be compared with the expected NPV for each of the four investment options if they were to proceed immediately, as shown in Table 2.

Table 2. Expected NPV if investment is undertaken immediately

Investment option	NPV (EUR m)
Gas	242
Coal	76
Coal+CCS	-746
Nuclear	-224

Nuclear and coal+CCS both have negative expected NPVs under immediate investment. The NPV for nuclear is very sensitive to capital cost assumptions, and as can be seen in Figure 8, if capital costs turn out lower than expected, nuclear becomes the preferred option in most scenarios, whereas if nuclear capitals costs turn out higher than expected it can make significant losses. By investing in Period 0, the investor gets the average of these two sets of outcomes, which is negative overall. Coal+CCS also has a negative expected NPV because under the central price assumptions for carbon in this example it is not a cost-effective investment option.

Of the investment choices in Table 2, gas is the most cost effective with an NPV of EUR 242m under the central assumptions used here, and therefore looks like an attractive investment option to carry out immediately since it satisfies the usual positive NPV rule. Nevertheless, as we can see from the decision matrix in Figure 8, the NPV that can be obtained by waiting until Period 1 is an even better EUR 472m. The option value of waiting is simply the difference between the two: EUR 472m - EUR 242m = EUR 230m. This EUR 230m is the amount that a firm might be willing to forego in order to "buy" the option to wait and optimise their investment decision. This cost might arise either in terms of opportunity cost resulting from lost earning due the deferment of investment, or as a direct expenditure for example on existing plants in order to maintain market share during the period of waiting. In order to justify proceeding immediately rather than deferring investment, either the profitability of new plants, or the costs of refurbishment of existing plants (or some combination of the two) would need to exceed this option value.

4.3. Key drivers of option value

Clearly, this option value depends on the assumptions that go into the cash-flow model, both in terms of the central values for each of the parameters as well as the variability between high and low scenarios. The particular value presented here of EUR 230m is simply an illustrative example based on one set of assumptions. The aim of this paper is not so much to provide an accurate assessment of this option value, but to provide an order-of-magnitude comparison with refurbishment costs, in order to show the possible role that uncertainty can play in decisions around refurbishment vs. replacement. The model presented here allows relatively simple analysis of the driving factors behind this option value by looking at the sensitivity of the option value to the key cash-flow parameters. This sensitivity is explored here through comparative statics where each key parameter is varied individually in turn. Results are shown in Figure 9.

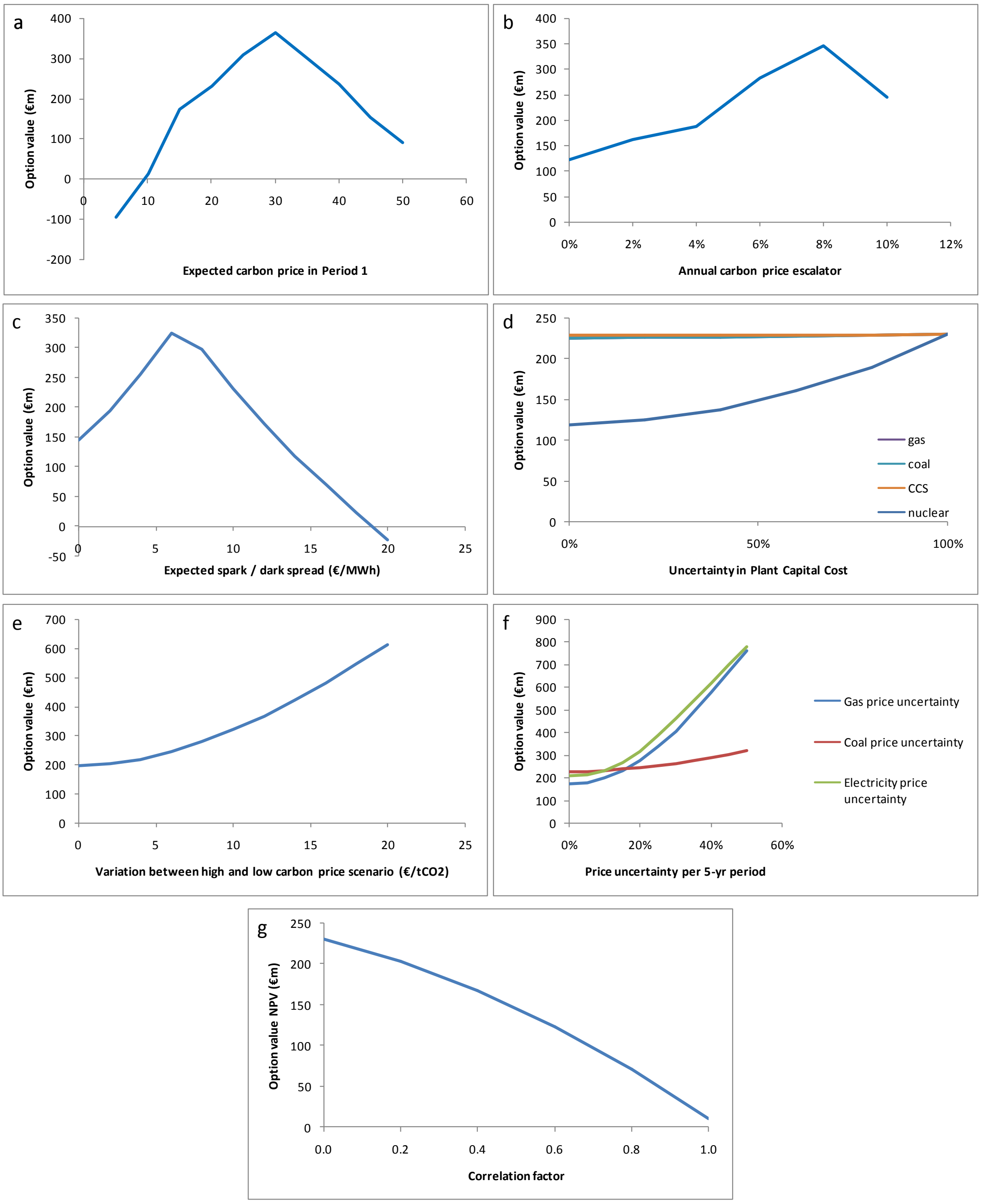
These option values can be interpreted either as representing the risk premium or additional hurdle rate that a new plant would need to exceed in order to justify immediate investment, or as the amount of money that firms might be willing to pay to refurbish existing plants in order to maintain market share and "buy" the option to wait until a more optimised investment decision can be made. These option values show some instructive trends:

a) When expected future carbon prices are very low, the model chooses coal plants in most scenario combinations, and there is little value in waiting to optimise this choice. For moderate values of carbon, the option value of waiting increases as the carbon price increases. This is because the total value of investments increases in general (except for coal plants) because of the feedthrough of carbon prices to the electricity price. However, at higher carbon prices, the option value of waiting diminishes again because the chances of making a costly mistake diminishes as the NPV of low carbon technology investments improves. At carbon prices of around EUR 50/tCO_2 the option value of waiting disappears, and it becomes more cost-effective to invest immediately due to the high paybacks.

b) A similar trend is apparent with the carbon price escalator. This escalator controls the expected annual increase in the central carbon price scenario. A strongly increasing carbon price can lead to a value of waiting resulting from the fact that the economic case improves over time. However, the value of flexibility to optimise by waiting gets curtailed for similar reasons to case a) in that the economic case becomes dominated by the carbon price, and there is less to choose between the different low-carbon technologies under the different scenario combinations.

c) The spark/dark spread measures the additional increment on the electricity price that is over and above the short-run operating costs of the marginal plants (either coal or gas plants depending on the price scenario). At low levels, the option value increases with the spark/dark spread because the overall profitability of projects increases. However, at moderate to high spark/dark spreads, the option value of waiting diminishes because all projects start to become profitable. With no losses to avoid, the value of waiting to optimise the investment choice becomes less attractive than investing immediately to make use of the high profit margins.

Figure 9. Sensitivity of option values to key modelling assumptions



d) The x-axis measures the degree of resolution of capital costs uncertainty: 100% means the full range of cost uncertainty is resolved by waiting one 5-year period, whereas 0% means that there is no variation in capital costs between the high and low scenarios (reducing the option value of waiting). The only capital cost uncertainty parameter that makes a difference to the results is the nuclear capital costs. Coal and gas plants investment choices are driven more by fuel price variations than capital cost, and the uncertainty in capital costs for these technologies is smaller than for nuclear. CCS on the other hand does not contribute much to the option value calculated in Figure 8 since it is not often implemented at those expected carbon prices, so the option value is not sensitive to variations in CCS cost.

e) The option value of waiting increases steadily as the variance between the high and low scenarios for carbon price increases. The x-axis here measures the difference between the central and high/low scenarios in absolute EUR/tCO_2. This is the extent to which investors might expect to gain lasting knowledge about the new price regime by waiting, which is not the same as the total volatility or uncertainty in prices.

f) For moderate levels of uncertainty below about 10%, the value of waiting is relatively insensitive to assumptions about how much an investor will learn with respect to fuel and electricity prices by waiting for one 5-year period. However, in the case of gas and electricity, once these learning rates exceed 10% they start to dominate the option value, and waiting becomes significantly more valuable as the assumed level of deviation between price scenarios increases. Option values are insensitive to uncertainties in coal price.

g) The correlation between the six scenario parameters has a strong bearing on the option value. If there is full correlation (*i.e.* between electricity, carbon, gas, coal and capital costs), then there will only be two scenario outcomes, "all high" or "all low". This leads to a much lower option value than in the uncorrelated case where all 64 cases are equally likely, leading to the maximum benefits of waiting to optimise the investment choice. The reality will be somewhere in between these two extremes, although evaluating these correlations accurately *a priori* would be difficult.

4.4. Implications for refurbishment vs. replacement

The higher the option value, the more likely it is that a company will prefer to wait, slowing down plant turnover rates. The trends in Section 4.3 therefore have important implications for refurbishment vs. replacement investment decisions.

The first point to note from these results is that the value of waiting before investing is substantial, typically in the range EUR 100-300m (which is in the region of 8-25% of the capital costs of a new coal plant). This option value is the expected value that accrues to the company as a result of waiting rather than investing immediately. One way in which companies might be able to realise this value is if they can keep existing plants operating for longer such that the new investment can be delayed pending further information and clarification regarding future investment conditions.

As discussed in Section 3, options are often available for plant life extensions that are well within this budget. Even a full refurbishment to extend plant life by 10-15 years may be within this budget under some conditions, although in practice, less drastic refurbishments would probably be chosen depending on the timescale over which deferment of the new build decision was being considered, and depending on the particular conditions of the old plants.

The interactions between refurbishment decisions and new build options are therefore quite complex. As time passes, older plants will become more expensive to maintain, and the discrepancy between the dropping efficiency of the aging plants and the improving performance of new plants will become high enough to justify a move to build the new plants. At this point the old plants do not necessarily retire, but move lower down the merit order, and operate at reduced load factor under a different set of economic conditions. Until this time comes, the option value of waiting to invest in new plants provides an incentive to invest in existing plants sufficiently to keep it operating during the period of waiting.

Figure 9c shows that this incentive to invest in refurbishment rather than new plants may be significantly reduced if investments in new plants are expected to be more profitable. This might occur for example through higher electricity prices and/or if carbon prices are sufficiently high (or expected to increase sufficiently rapidly over time), which will tend to exaggerate the economic impacts of the efficiency discrepancy between existing plants and new plants. Secondly, reducing uncertainty with regards to carbon, fuel and electricity prices would tend to reduce the incentive to invest in existing plants, and would help to incentivise greater plant replacement rates.

In the case where option values are high (implying a greater incentive to keep existing plants running longer), it may be necessary to consider additional regulatory measures, either to speed up replacement rates, or to enforce refurbishment up to some minimum efficiency standard. One example of the former has been implemented in China's 11th 5-year plan, where all plants below 100 MW have already been closed down and plants below 200 MW are due to be phased out over the 5-year plan. These smaller plants tend to be older, and because of the economies of scale, efficiency improvements can be gained by replacing with larger plants. There do not appear to be equivalent examples of refurbishment policies in the power sector aimed specifically at efficiency improvements. However, as previously discussed, broader environmental regulation can have very significant impact on the financial viability of older plants. The favourable economics of existing coal plants relies largely on the fact that the large capital costs have been sunk, and operating costs are typically relatively low, such that they can make a return with relatively small profit margins. However, if significant investments are required in order to meet new environmental standards, these may no longer be viable within these low profit margins. Section 2 illustrated the case in the United States where many refurbishments were interpreted as not requiring plants to meet new SO_2 and NO_x emissions standards. This allowed refurbished plants to operate profitably in comparison with new plants, leading to a much aged fleet.

In other cases, imposing standards on existing plants can accelerate plant replacement cycles. A current example in the European Union is being implemented through the Large Combustion Plant Directive. The Directive sets standards for emissions of SO_2 which effectively require plants to fit flue gas desulphurisation (FGD) equipment. This is a capital intensive investment, and reduces the operating efficiency of plants, and fitting FGD to older plants does not make economic sense. Existing plants are allowed to opt in (meaning they will have to meet the new environmental performance standards by 2015), or they can opt out (meaning they have a limited number of hours they can run up to 2015 at which point they must cease operation). If this Directive is strictly enforced, companies will no longer be able to indefinitely extend the lifetime of existing plants, which significantly changes the analysis of refurbishment vs. new build decision-making.

So decision-making on refurbishment will in practice be a complex mixture of factors that extend beyond the underlying economics to include issues of risk, regulation and other strategic factors. In fact, as discussed in the next section, the range of factors extends well beyond the power generation sector.

5. The wider power system context

The discussion so far in this paper has been about replacement vs. refurbishment decisions in the power generation sector. However, in practice these decisions cannot be treated in isolation from the wider context of the power system. Important contextual factors include the physical characteristics of the electricity transmission and distribution system, the design of electricity markets and regulatory frameworks, and the nature of the demand sectors.

In countries which have undergone a liberalisation of their electricity systems, ownership of generation assets has generally been separated from ownership of the transmission and distribution assets. In more traditional commodity markets, such separation of ownership and operation between production and transportation companies is common, and quite straightforward. Transportation companies can make a profit by moving goods from locations where they are cheap (*i.e.* where they are produced), to where they are more expensive (*i.e.* where they are consumed). The electricity system is however much more complex because of the need for real-time balancing of supply and demand, and the need to keep the whole system (generators, transmission, distribution and demand) operating in synchronicity.

As far as the laws of physics are concerned, the electricity sector is a single highly integrated system comprising all the generators, transmission lines, distribution networks and demand-side appliances. However, ownership of this system is sub-divided amongst many different (and disparate) groups. In complex grids, the path of electricity flow between generation and consumption is difficult to track, and depending on the presence of constraints and congestion in the system, does not always follow a simple flow from regions of high price to regions of low price. It is therefore problematical to design systems that allow transmission companies to accurately recoup the cost of transporting electricity between generators and consumers.

Transmission systems are often considered to be natural monopolies because:

- Given the visual impact of transmission lines, obtaining planning for new lines is difficult, and the construction of multiple lines along similar routes is very unlikely to be tolerated.
- Economies of scale are large because the fixed costs of installing new transmission lines are high since costs are often determined more by the length of the transmission line rather than the capacity it can carry.
- Networks need to achieve a certain size before they can operate efficiently and reliably.
- Transmission assets are very capital intensive, in that expenditure required to lay new transmission lines and install the associated switch gear and transformers is very large compared to the subsequent operating costs.

Transmission and distribution assets have a very long life (often 20 to 40 years or even longer), and systems in the OECD have built up over many decades. These systems are not generally optimised to current generation and load profiles, but have evolved and adapted on a more *ad-hoc* basis, usually leaving existing structures in place because of the substantial sunk costs in the existing system. Estimates for the United States suggest that of a total capital asset base of USD 800 billion in the electricity system as a whole, 40% is in the transmission and distribution system.[23]

New investments in transmission have to be undertaken carefully because they are essentially irreversible. This creates difficulties when contemplating more disruptive scenarios of change in the

[23] US Department of Energy, Office of Electricity Delivery and Energy Reliability http://sites.energetics.com/gridworks/grid.html

electricity system. Existing sites will generally have an advantage over new sites because the transmission infrastructure already exists to absorb the new power generation (as well as often having advantages in terms of being easier to get through local planning processes). The existence of the current physical infrastructure designed around large centralised generation plants therefore tends to favour continuation of similar centralised generation options (*e.g.* coal, nuclear, CCGT), whilst disadvantaging sources in different geographical locations. The latter includes renewables, since the locations of good wind, wave, biomass and solar resources are not necessarily well aligned with the existing locations of power plants. Adapting the transmission system to incorporate a high penetration of renewables sources would entail additional costs depending on the extent of these differences in location.

A study for the United Kingdom in 2002[24] concluded that if wind power (mostly concentrated in the north of the country) were to supply 20% of total electricity demand, additional transmission infrastructure costs would be in the region of GBP 90m per year, an increase of 6% compared to the current annual capital expenditure of National Grid, the transmission company. These costs could rise to GBP 240m for a 30% penetration of wind, an increase by 17% compared to current capital expenditure. In the case of wind power, the intermittency of supply means that additional capacity is required to maintain system reliability, with associated annual costs estimated at GBP 280m for a 20% penetration and GBP 620m for a 30% penetration.

The physical location and characteristics of these new resources is only one aspect of the problem. Incentive mechanisms for the transmission companies to build the new lines and for the system to provide the additional back-up capacity also have to be designed, resolving questions about who will pay. This is not a trivial problem, since putting all the costs on the first company to develop a generation project in a particular location creates a very large first-mover disadvantage. On the other hand, sharing the costs of all grid developments equally across all system users may not give sufficiently strong signals to ensure economically efficient development. A full discussion of these issues is beyond the scope of this paper, but questions of market design will determine who carries the burden of these broader system investments, and can have a significant impact on the economics of power generation investment decisions.

The other important factor to take into account is the nature of electricity demand. Because most customers are not exposed to real-time pricing, and do not generally have the technical means to respond rapidly to price changes, electricity demand is considered to be very price inelastic in the short-term. Fluctuations in demand (or supply) are therefore usually met by ramping up or down the generators on the system. The flexibility of power generators to respond in this manner is therefore a valuable contribution to the system, in addition to the pure energy they provide, and some minimum level of "dispatchable" generation (*i.e.* not including nuclear or non-thermal renewables) will usually be needed on the system. However, the nature of the demand sectors could change if smart grids and metering enables non-essential appliances to be switched on and off automatically in response to price fluctuations. A high penetration of electric cars could also significantly alter demand profiles, especially if these were combined with smart metering to allow batteries to be charged at non-peak hours.

These technological and behavioural changes have knock-on consequences on all the other parts of the system, and need to be taken into account in companies investment plans. Such changes can be signalled to other groups in the system through changes in pricing, but uncertainties related to projecting these changes into the future mean that to some extent such signalling will never be

[24] "Quantifying the System Costs of Additional Renewables in 2020", A report to the Department of Trade and Industry, ILEX Energy Consulting.

perfect. The broader electricity system can therefore also exert a number of influences on power generation investment decisions, resulting for example from the costs of connecting to the grid, the regulatory and planning systems for such connections, the market rewards for providing pure energy vs. dispatchable capacity, and the forecast patterns of demand. To the extent that these factors may be uncertain, there can also be an additional tendency for power generation companies to want to delay investment in new plants if there is a prospect to learn about developing trends in other parts of the system.

6. Conclusions

The rate of transition to a low-carbon energy system will be largely determined by the rate of turnover in capital stock, driven by policies that create incentives for companies to make the necessary investments.[25] Such incentive mechanisms need to be carefully designed, so that they compensate companies not only for the higher costs of low-carbon technologies, but also for the risks associated with such a transition. Micro-economic analysis can be a useful tool to explore how investment decisions are likely to be influenced in practice by factors that are often left out of macro-economic analysis, and therefore how real behaviour is likely to deviate from economic models. Such deviations could arise from a number of factors that managers tend to take into account. These include dealing with risk and uncertainty, optimising decisions over a company's broader portfolio of plants, taking into account strategic factors, and responding to various barriers to investment. This report focuses on the first of these factors.

Companies will generally have a motivation to extend the life of existing plants when they face uncertainty over the future of their investments. The capital costs of refurbishing existing plants is often much lower than building a new plant. This can influence decisions to invest in new plants even if the new plants seem to be more cost-effective than the old plants in terms of the cost per unit of electricity produced. Policy mechanisms that are designed to stimulate investment in new capital stock will therefore need to provide greater incentives in order to overcome these effects of risk and the tendency to keep old plants running longer. Analysis presented in this paper suggests that uncertainties regarding investment conditions could be a significant factor behind decisions to delay plant replacement. The option value of waiting can often be in the region of EUR 100-300m, representing 8-25% of the capital costs of a new coal plant, and can be significantly higher than the capital costs required for carrying refurbishment and plant life-extension projects for existing plants.

The incentive to delay new investment becomes significantly lower if these investments are expected to be more profitable, for example through higher electricity prices and/or if carbon prices are sufficiently high (or expected to increase sufficiently rapidly over time). In addition, reducing uncertainty with regards to carbon, fuel and electricity prices could restrict the option value of waiting and help to incentivise greater plant replacement rates.

The more widespread the energy transition, the more widespread become the associated risks and uncertainties. Companies will need to factor in assumptions to their investment decisions that are far from current equilibrium conditions. Risk factors arise well beyond the traditional electricity generation-transmission-distribution-consumption chain, to include risks in the gas supply system, new sources of demand (*e.g.* potential shifts in transportation energy towards electricity) and new sources of supply or competing business models (*e.g.* distributed vs. centralised generation, or radical improvements in energy efficiency).

If carbon prices are to be the main policy mechanism driving new investment towards low-carbon technologies, then the carbon price will need to rise in order to overcome these effects of risk. In theory, under a cap-and-trade scheme, such price rises would be expected to occur automatically, since a delay in the replacement of old plants with new lower-carbon plants would lead to an increased demand for allowances. The presence of risk would therefore lead to a new market

[25] Broader changes to the energy system are discussed in a separate paper in this IEA Information Paper series "Macro-economics of Transition".

equilibrium, with higher carbon prices but the same level of emissions. Achieving this kind of well-functioning carbon market requires that policy-makers and market regulators recognise the need for such price rises and allow them to occur. Price caps or other limits will restrict the ability of prices to adjust to take account of these risk factors.

In the case of a carbon tax, the presence of risk leads to a lower level of abatement for any given price level, so in order to meet a particular emissions target, the tax level would need to be increased to address the risk factors. In countries where the power sector is based on a market system, such price-based mechanisms should be effective, since operating and investment decisions are routinely based on the price and costs of input factors.

Nevertheless, non-price based policy mechanisms also exert a strong influence in the power sector. Although policies rarely require refurbishment of old plants purely on the basis of efficiency or greenhouse gas emissions performance, policies that require minimum environmental performance relating to other pollutants (*e.g.* SO_2, NO_x, particulates) are common. In cases where environmental policy exempts older plants from meeting standards, plant replacement cycles can be significantly slowed down, resulting in an aging of the generation fleet, and stagnation in efficiency levels (as has been seen in the US coal fleet). Conversely, older plants may be retired if they have to meet environmental standards that would require non-cost-effective capital investment (*e.g.* in flue gas desulphurisation). In this case, plant replacement cycles may be accelerated, leading to an opportunity for improved greenhouse gas emissions performance from the power generation sector.

The scale of the transition required to meet climate change goals requires more than incremental efficiency improvements in coal plant performance. Significant decarbonisation will involve more disruptive changes both in terms of technologies and broader system/market design. From the point of view of coal-fired generation, the success or otherwise of carbon capture and storage is a determinant of whether a smooth and directed pathway remains available. If not, the transition pathway is likely to be much more disruptive, although for the sector as a whole, the potential for CCS forms just a part of the diversity of possible technological options.

Broadly speaking in the electricity sector, refurbishment can bring efficiency levels back up to levels closer to the design specification of the existing plants, but will not usually bring them up to levels achieved by new plants. The option to refurbish or extend the life of existing plants therefore presents a hindrance to deeper emission cuts. This is not necessarily the case in all sectors. In sectors where asset lifetimes are particularly long (*e.g.* buildings), it may be worthwhile investing sufficient capital on existing assets to bring more radical performance improvement. In these cases, policies that specifically target the refurbishment of capital stock to improve energy performance may be needed. These cases will be explored in other papers in this series.

Appendix – Model assumptions

The cash-flow model in used in this paper calculates the NPV in each of the 64 different scenario combinations of the decision matrix as described in Section 4. The NPV is calculated as:

NPV = Present value of gross margin after tax over plant lifetime
- capital cost of investment adjusted for interest paid during construction

The gross margin is simply the project revenues minus the fixed and variable operating costs and fuel costs, and is then adjusted for tax at a rate of 30%. Present values are calculated at a discount rate of 7.5%. Data for the operating and capital costs of plants are taken from the recent EU assessment.[26] Oil, gas and coal price scenarios are taken from the EU Energy and Transport trends.[27] Electricity prices are assumed to follow the short-run marginal costs of either coal plants or gas plants depending on which one has the higher operating cost in any given scenario, and thereby forming the marginal plants in the dispatch order. Costs and prices are shown in Tables A.1 and A.2. Table A.3 shows the extent to which price information improves by waiting. The "learning rates" presented here are the extent to which the high and low scenarios for each variable deviate from the mean over the 5-year waiting period. These high & low scenario deviations are shown in Table A.1 and A.2 for capital costs and carbon prices respectively.

Table A.1. Cost assumptions in the cash-flow model

		Coal		**Coal + CCS**		**Gas**		**Nuclear**	
Year		2010	2035	2010	2035	2010	2035	2010	2035
Expected overnight capital costs 1 000 MW, EUR m	Hi	1440	1296	2700	2451	730	693	3380	3380
	Low	1000	900	1700	1543	480	455	1970	1970
	Med	1265	1139	2250	2043	635	603	2680	2680
Build time	years	3		4		3		6	
Economic lifetime	years	25		25		25		25	
Non-fuel O&M	€m	60		90		25		90	
Efficiency		47%	54%	35%	42%	58%	65%	35%	36%
Central fuel price	€/MWh_{th}	7.1	7.4	7.1	7.4	21.4	23.8	2.6	3.6
Load factor		86%		86%		87%		86%	

[26] EU Commission (2008), "Energy Sources, Production Costs and Performance of Technologies for Power Generation, Heating and Transport", Commission Staff Working Document Accompanying the Second Strategic Energy Review COM(2008)744.

[27] European Commission (2008), "Trends to 2030- 2007 Update", Directorate General for Energy and Transport.

Table A.2. Price scenarios in the cash-flow model

	Central fuel price scenario 2005 USD/toe				Spark spread	Carbon EUR/tCO2		
	Oil	Gas	Coal	Nuclear	EUR/MWh	hi	lo	med
2010	392	299	99	37	10	25	15	20
2015	417	312	103	40	10	32	19	26
2020	440	331	106	44	10	41	24	33
2025	449	340	107	47	10	52	31	42
2030	452	343	107	50	10	66	40	53
2035	456	346	108	53	10	85	51	68
2040	459	348	109	56	10	108	65	86
2045	463	351	109	59	10	138	83	110
2050	467	354	110	62	10	176	106	141

Table A.3. Learning by waiting assumptions

Gas price learning over 5 years	15.0%
Coal price learning over 5 years	7.5%
Spark spread price learning over 5 years	10.0%

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