RETROFITTING CO_2 CAPTURE TO EXISTING POWER PLANTS

Report: 2011/02

May 2011

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IC Consultants Ltd, UK

The principal researchers were:

- Jon Gibbins University of Edinburgh
- Hannah Chalmers University of Edinburgh
- Mathieu Lucquiaud University of Edinburgh
- Niall McGlashan Imperial College, London
- Jia Li Imperial College, London
- Xi Liang University of Cambridge

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The IEAGHG manager for this report was:

John Davison

The expert reviewers for this report were:

- Dale Simbeck SFA Pacific
- Howard Herzog MIT
- Des Dillon EPRI
- José Figueroa NETL

Further comments on the draft report were also received from Parsons Brinckerhoff, UK.

The report should be cited in literature as follows:

'IEAGHG, "Retrofitting CO_2 Capture to Existing Power Plants, 2011/02, May, 2011.'

Further information or copies of the report can be obtained by contacting IEAGHG at:

IEAGHG, Orchard Business Centre,
Stoke Orchard, Cheltenham,
GLOS., GL52 7RZ, UK
Tel: +44(0) 1242 680753 Fax: +44 (0)1242 680758
E-mail: mail@ieaghg.org
Internet: www.ieaghg.org

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Background to the Study

Retrofitting CO_2 capture and storage (CCS) to existing power plants is one of the many ways of substantially reducing CO_2 emissions from power generation; others include replacing existing fossil fuel power plants by new power plants with CCS or the use of renewable or nuclear energy. Partial reductions of emissions can be achieved by efficiency improvements and switching to lower carbon fuels

Global rollout of proven CCS technologies on power plants is not expected to commence until 2020 at the earliest but deep reductions in emissions from electricity generation are expected to be required by as early as 2030 in some developed countries and by 2050 globally, well within the lifetimes of some existing power plants and plants that will be built between now and the time when CCS becomes widely available. It is therefore likely that some of these plants will have to either close prematurely to be replaced by new low-CO_2 sources of electricity or they will have to be retrofitted with CCS. A programme of CCS retrofits would require less construction activity than replacement by new power plants. This could allow CO_2 capture to be deployed more quickly than would be possible if new plants must be built before any CO_2 capture can be implemented.

This study assesses at a generic level the relative merits of retrofitting CCS to existing power plants and building new plants with CCS. As such it focuses mainly on the question "is CCS retrofit worth doing" rather than "can it be done". The latter would need to be addressed by detailed site specific studies for individual plants, examples of which are being undertaken by other organisations. However, the study also reports on high-level assessments of the potential for CCS retrofits in various countries: the USA, UK and China.

IEAGHG commissioned IC Consultants Ltd to carry out this study and the work was undertaken by staff of the University of Edinburgh, Imperial College London and the University of Cambridge.

Methodology

The study involved defining a range of CCS retrofit options for pulverised coal and natural gas combined cycle power plants and then assessing their efficiencies, emissions and relative costs compared to each other and to new build plants with CCS. Costs are presented mainly in terms of the levelised cost per MWh of electricity generated and some consideration is also given to the cost per tonne of CO_2 emissions abated from an existing plant.

As a generic study, this study was not able to address future costs for construction, fuel etc. or site- and region-specific questions that will govern the feasibility and cost of a specific retrofit project, although it does discuss some of the principles involved and examines sensitivities.

For a generic assessment of the relative costs of retrofit and new build it is necessary to assume that CO_2 transport and storage from the site of the existing plant is technically and economically feasible. Obviously this will not always be the case, although some preliminary studies (for the

USA and the UK) that are reviewed in this report suggest that access to storage would be feasible for many existing power plant sites. It is also necessary to assume that space and layout constraints for an existing plant do not prevent retrofit, and also would not prevent building a new power plant with CCS at the same location. This is also obviously a very site-specific factor, but again previous studies of fleet retrofit potential suggest that significant numbers of power plant sites would be able to accommodate retrofit (and so presumably new build) with CCS.

It is also implicit in a generic evaluation of their respective merits that the retrofit and new build plants will not receive significantly different benefits or disadvantages as a result of their location. This is most likely to be the case if the same site was to be used for both options. Such re-use of existing sites is likely to be widespread, to take advantage of features such as existing grid connections, water supplies and coal or gas delivery facilities. Local communities are also more likely to be accustomed to power plant developments on existing sites.

The most reliable estimates for relative costs of retrofit and new build will be obtained if it is assumed that similar capture technologies are used for both. Then, while absolute costs may vary, they will do so in a similar way for both options. In this study post-combustion capture has been used as an example of a technology which can be retrofitted but is also suitable for new build. Oxyfuel (or other suitable capture technologies) could also be an alternative, but less published information is available on which to base estimates. It is important to note that most comparisons of capture technology options show small differences in the overall costs of generation for all the main CO_2 capture options for coal: gasification and pre-combustion capture, oxyfuel and post-combustion capture. While this remains the case, trends observed for comparisons between post-combustion retrofit and new build options for coal will probably also hold for comparisons between post-combustion or oxyfuel retrofits and gasification, oxyfuel and post-combustion new build replacements respectively.

For natural gas fired power plants, based on the relatively limited work undertaken to date, post-combustion capture appears to have lower costs for new build plant than alternatives, as well as being suitable for retrofitting. Clearly, practical experience may eventually show that one particular capture technology is superior and this will then become the *de facto* option for new build, and possibly retrofit, applications. Similarly, if other low carbon generation options (e.g. renewables or nuclear) are found to be more attractive on balance than a new build CCS plant for a particular project then these may instead become the alternative to a CCS retrofit for reducing emissions from an existing fossil fuel power plant. An assessment of the possible future differences between capture technologies, and between these and other low-carbon generation options, is obviously beyond the scope of this report. Many of the principles that are discussed will however still be applicable.

The most important principle when making a comparison of retrofit and new build options for reducing CO_2 emissions from existing plants is that a consistent and correct baseline is used for all cases, particularly when presenting the relative costs per tonne of CO_2 abated. The cost of abatement is calculated in this study by comparing the costs and emissions of a plant with CCS versus the costs and emissions of a baseline, which is assumed to be an existing plant without CCS for both retrofit and new build plants with CCS. Errors in the baseline have arguably been the most serious barrier to both a proper assessment of CCS retrofits and also an understanding of the incentives required to reduce CO_2 emissions from existing power plants.

An economic assessment model was developed for this study and was used to assess the sensitivities to the values of significant input parameters, including the efficiency of the existing power plant, the efficiency penalty for capture, the load factor, the capital costs of new power plants and capture plants, fuel prices, discount rate and plant life. Although a large number of cases were evaluated clearly not all possible combinations that may be of interest in particular circumstances could be assessed. The spreadsheet model will be made available to IEAGHG's members to enable them to evaluate additional parameter values if they wish to do so. However, it should be recognised that the model was developed primarily for internal use by the study workers and it was not possible to devote resources to development of a professional user-interface and help facilities.

Results and Discussion

Factors affecting the cost of CCS retrofit

An important determinant of the relative costs of new build and retrofit CCS is the capital cost. If the alternative to retrofitting an existing power plant is to close it down and replace it with a new power plant then, even if it is not yet formally written off, the effective capital cost of the existing plant for decision-making purposes is zero[1], although the additional costs for any refurbishment (and subsequent maintenance) to give the necessary further operating life will also need to be considered. This reduced effective capital cost means that levelised electricity costs (e.g. $/MWh) for an existing plant without capture may be lower than for a new build fossil power plant without capture.

The additional costs of CCS per tonne of CO_2 captured are likely to be somewhat higher for retrofitted plants, for the following reasons:

a) the relative cost of installing a retrofitted capture unit may be higher since the power plant may not have been designed to receive it;

b) the electricity output penalty per tonne of CO_2 captured may be higher if it is more difficult to integrate the capture unit with an existing plant than with a new purpose-built plant;

c) the operating life of the CCS equipment may be lower than in a new built plant if it is limited by the residual life of the existing power plant.

d) a retrofitted plant would usually have a lower efficiency and higher marginal operating costs than a new plant and hence would be expected to operate at a lower average load factor.

The penalties from (a), (b) and (c) may be so high, under unfavourable site conditions, as to totally preclude a retrofit but no general way to determine their magnitude exists; they depend entirely on site conditions. The increased penalties from (a) and (b) above may be avoided or reduced if the existing plant is capture ready.

A lower load factor, as identified in (d) is unlikely to have a major effect on the profitability of a retrofitted plant, since the electricity price received by a new build plant operating for longer periods can be no higher than the short run marginal cost (SRMC) of the retrofitted plant (otherwise the latter would also have been running then). The additional net revenue that can be

[1] If the plant is otherwise to be closed, then strictly the 'capital' cost of keeping it open will be the scrap value less the decommissioning costs, although these are often assumed to be comparable.

applied to meeting other, fixed, costs (e.g. capital, salaries) is therefore just the difference between the respective SRMC values for the two plants. Since this SRMC difference will usually be small compared to overall costs, a simplistic calculation of comparative levelised cost of electricity (LCOE) values that assumes that the plant with the higher load factor is able to recover its fixed costs at the same rate for all of the time that it is operating is not correct. In fact, the new build plant would have to recover most of its overall costs during the same shorter period of time when both plants are operating and, presumably, electricity prices are higher than the SRMC of the lower-efficiency plant (so that the latter can also recover its fixed costs). Under these circumstances a retrofit, if it has lower capital costs to recover over this period, is likely to be at an advantage. A novel method that accurately shows the maximum benefit of SRMC differences for two plants with consequently differing load factors has been developed for this study. This yields an equivalent LCOE for the new build (higher load factor) plant for the period of time when both plants are operating, making a direct comparison possible.

In addition, an existing plant is likely to have a lower efficiency than a new plant and so more CO_2 must be captured, transported and stored per MWh. While this will affect the cost of electricity generation with and without capture it will have almost no effect on the cost per tonne of CO_2 abated for retrofitting, as discussed later, since lower efficiency plants have a greater increase in costs for retrofitting but these are in proportion to the reduction in CO_2 emissions compared to the same plant without CCS. Lower efficiency plants do, however, provide a relatively greater opportunity for fuel and other cost savings if the original plant is replaced by a more efficient new build unit. This makes a replacement with a new build plant more attractive, and new build options are therefore more likely to be economically competitive with a retrofit for lower efficiency existing plants than for higher efficiency existing plants.

Analysis of retrofit and new build plant options

When CO_2 capture is retrofitted to a power plant, the net power output will normally reduce due to the energy (electricity and in some cases steam) consumed by the CO_2 capture process. In many cases it is likely to be most appropriate to replace the lost power output with output from plants built elsewhere but there are circumstances in which the power output from a specific site has to be maintained. If the power output is to be maintained on-site then there are thermally efficient and cost-effective ways in which this can be done. The following configurations of retrofits to existing coal-fired power plants are proposed and analysed in the report but other intermediate variants are possible. Some of these retrofitted plants continue to be wholly coal-fired but some also include new natural gas fired units to provide steam for the capture unit and to generate additional power.

- Integrated retrofit
    - All of the steam required by the capture unit is extracted from the existing main steam turbine (as is also assumed for new-build plants with CO_2 capture).
- Boiler power-matched retrofit
    - A high pressure coal fired boiler and back pressure steam turbine is installed to fully restore the net power output of the plant to its original level and to provide part of the steam required for the capture unit. The remainder of the steam required for capture is provided by extraction from the existing steam turbine.
- Boiler heat and power-matched retrofit
    - A low pressure coal or natural gas fired boiler and back pressure steam turbine is installed to provide all of the steam for the capture unit and to restore the net power output of the plant to its original level.
- Gas turbine combined cycle power-matched

- A natural gas-fired combined cycle plant with a back pressure steam turbine is installed to restore the net power output of the plant to its original level and to provide some of the steam for the capture unit. The remainder of the steam required by the capture unit is provided by extraction from the existing steam turbine.
- Gas turbine combined cycle heat-matched
  - A natural gas-fired combined cycle plant is installed, which provides all of the steam required by the capture unit. The net power output of the plant is allowed to increase above that of the original plant.

The same options were also analysed for existing gas fired power plants, except that the plants used only natural gas fuel and the boiler power-matched retrofit was not analysed. In all cases the flue gas from any additional boilers and gas turbines is fed to a CO_2 capture unit.

It may be possible to retain the original plant's peak generation capacity, and so in some cases avoid the need for any addition boiler and turbine capacity, if capture can be interrupted temporarily during times of peak power demand. However, operation of the plant without CO_2 capture may only be permitted for short periods of time. Although the peak generation capacity would be maintained, the overall annual electrical energy output would still decrease after capture retrofit unless the load factor could be increased to compensate.

The net power outputs of retrofits to existing coal and gas fired power plants, based on the configurations described above, are shown in Figure 1, thermal efficiencies are shown in Figure 2, capital costs are shown in Figure 3 and levelised costs of electricity generation are shown in Figures 4 and 5. The detailed technical and economic assumptions used for these analyses are listed in the main study report. The ways in which site-specific factors and also general factors such as fuel costs and costs of capital affect the relative economics of new build and a range of retrofit options are examined in the study report. Capital costs of plants in general have increased greatly in recent years and are currently subject to much uncertainty. Higher power plant costs in general would favour the retrofit option over the more capital intensive new-build option. Higher costs for just the capture unit would favour new-build compared to lower efficiency retrofits, which require larger capture units per MWh of electricity.

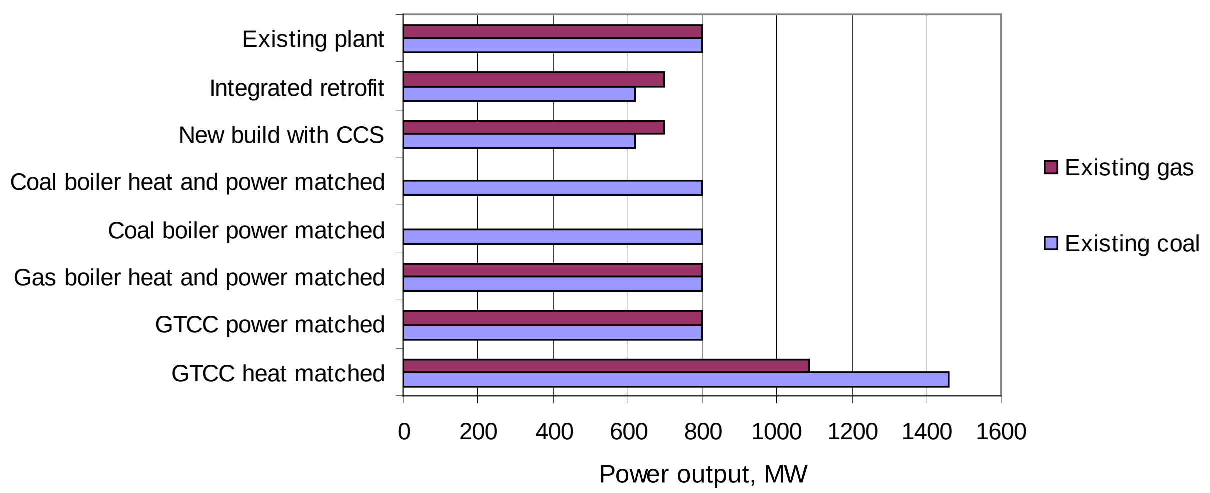


Figure 1 Net power outputs of retrofit and new build power plants with CO_2 capture[2]

[2] The new build plants are assumed to have the same net power outputs as the integrated retrofit plant but the net output could be the same as or greater than that of the existing plant if required.

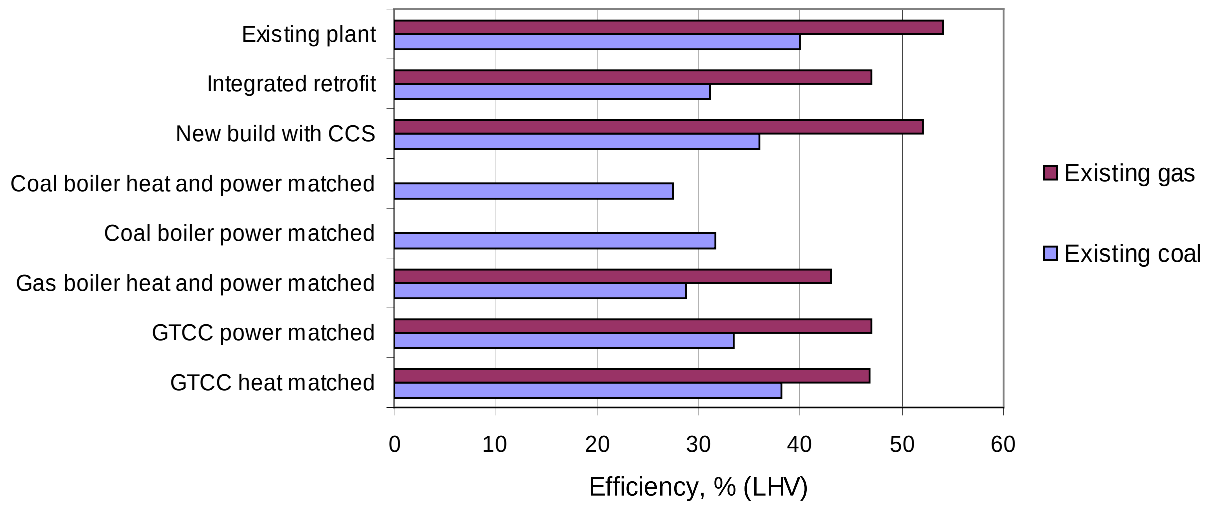


Figure 2 Efficiencies of retrofit and new build power plants with CO_2 capture

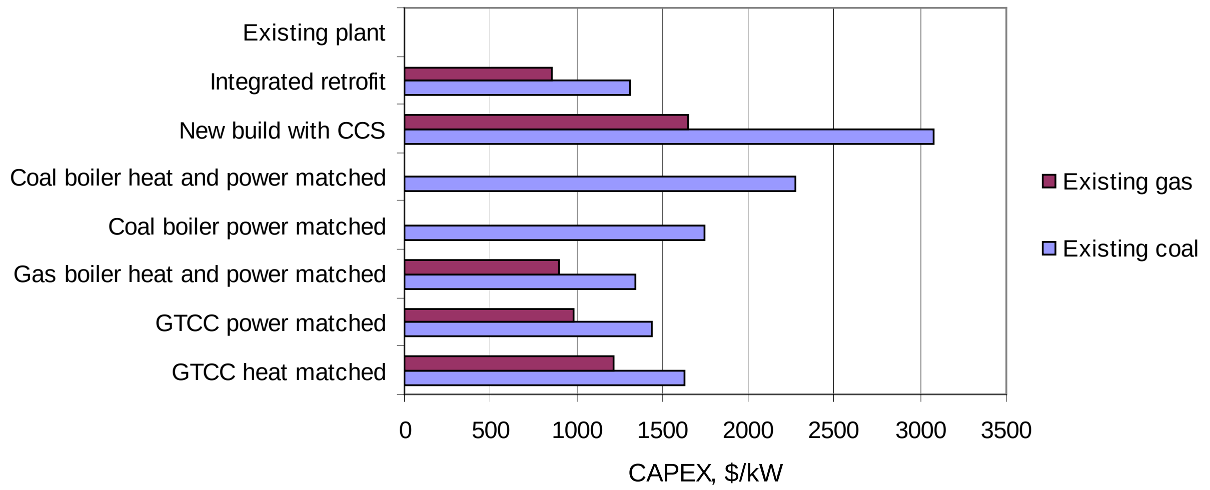


Figure 3 Capital costs of retrofit and new build power plants with CO_2 capture[3]

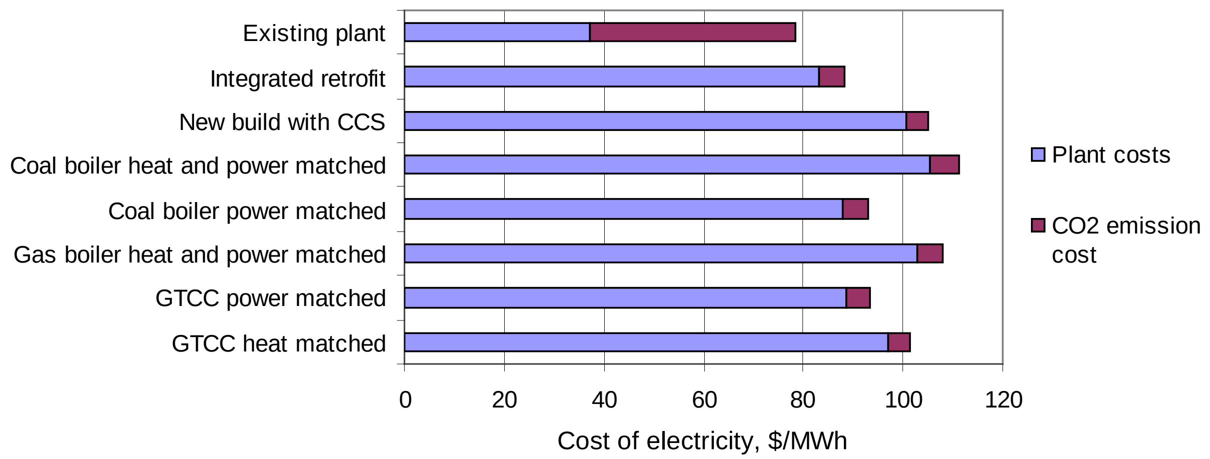


Figure 4 Levelised costs of electricity of retrofit and new build coal fired power plants with CCS[4]

[3] Overnight construction cost for a 'nth of a kind' plant, excluding capital cost of CO_2 transport and storage.

[4] Includes a storage cost of \$10/t of CO_2 stored. The CO_2 emission cost is based on \$50/t of CO_2 emitted.

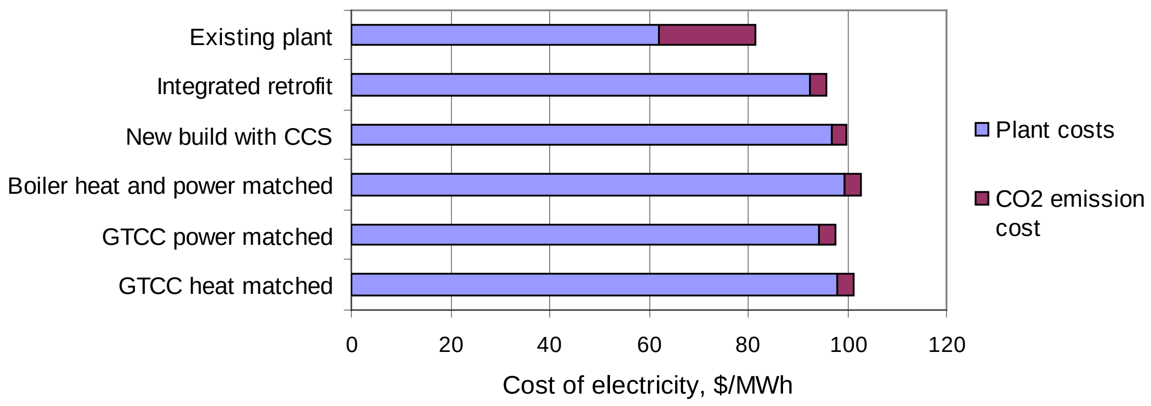


Figure 5 Levelised costs of electricity of retrofit and new build gas fired power plants with CCS[4]

The integrated retrofit plants have a lower thermal efficiency than the new build plants with CCS but they have a lower capital cost and a lower levelised cost of electricity. For the cases shown above the lower capital cost of a retrofit compared to scrapping and replacement by a new plant with CCS offsets the reduced efficiency and other additional capture costs for a retrofit.

In most cases, where heat is required to operate the capture equipment, the use of heat taken from the main power cycle, i.e. 'integrated retrofit', appears likely to give the lowest costs for post-combustion capture retrofits. Ways in which a similar energy and cost penalty per tonne of CO_2 captured can be obtained for retrofitted and new plants through effective integration between the capture equipment and the steam cycle in existing plants are described in the report.

The boiler heat and power-matched retrofits avoid the need to extract steam from the existing turbine, which could avoid problems at some sites, but they have relatively low efficiencies and high generation costs. The GTCC heat-matched option also avoids the need for steam extraction from the existing turbine and it has a relatively high thermal efficiency for a coal fired plant retrofit, but it has a high natural gas consumption and a substantially higher net power output than the original plant, which may not be acceptable at some sites.

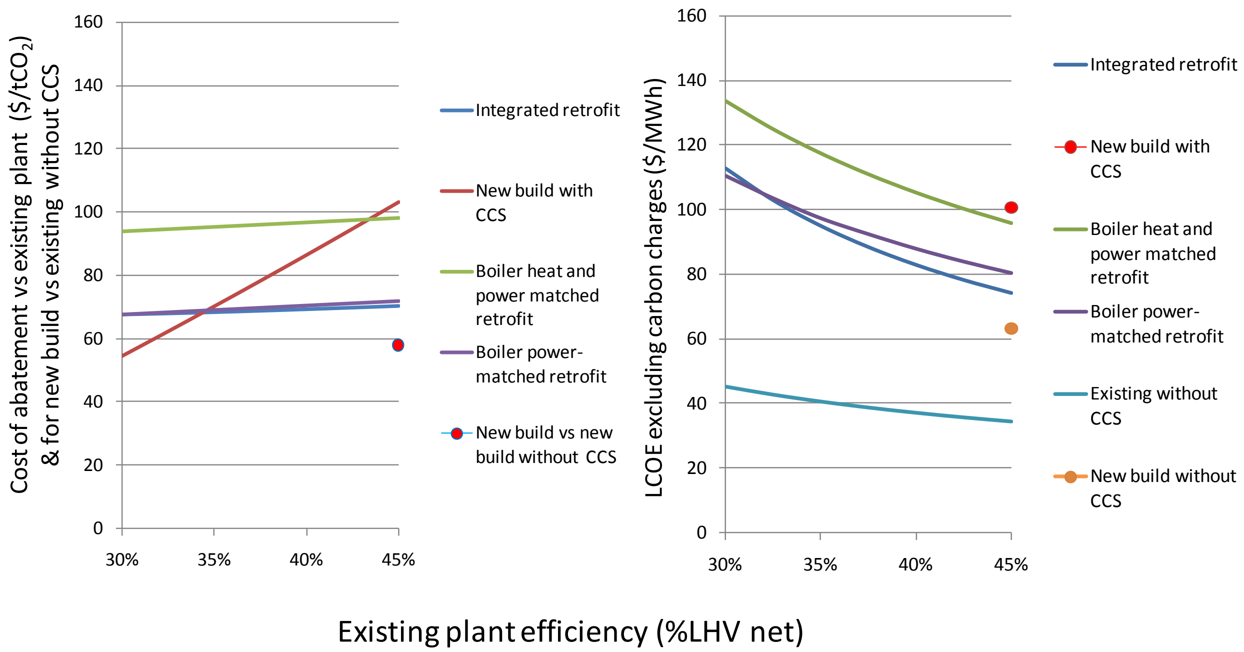
As shown in Figures 4 and 5, the cost associated with emitting CO_2 has a large impact on the cost of electricity from an existing plant without CCS, particularly for a coal fired plant, but a low impact for all CCS options (since it is assumed that CO_2 from any additional fuel use after retrofit will be captured). As such, CO_2 price can be expected to have a large effect on whether or not to install CCS but it will have a relatively minor effect on the choice of CCS option.

Effects of the efficiency of the existing power plant

The sensitivity of the levelised cost of electricity (LCOE) and the cost of CO_2 abatement to the efficiency of an existing coal-fired power plant are shown in Figure 6. The cost of CO_2 abatement is calculated by comparing the costs and emissions of new and retrofitted plants with capture versus the costs and emissions of the existing plant without capture. Additionally, for comparison, the cost of CO_2 emissions required to cover the costs of building and operating a new plant with CO_2 capture instead of without are shown (red circle in Figure 6a, at assumed new build efficiency of 45%). All of the plants illustrated in Figure 6 are fuelled entirely by coal, which is assumed to be priced at $10/MWh LHV basis ($2.78/GJ).

As shown in Figure 6b, the levelised costs of electricity are higher for retrofits to low-efficiency existing power plants. For the parameter values assumed for Figure 6, the threshold efficiency below which retrofit on these coal plants becomes unattractive is in the region of 35% LHV net (approximately 33% HHV net). Sensitivity studies for coal plants in this report are for a range of 35% to 45% LHV efficiency, and there are a limited proportion of cases where new build LCOE values are attractive compared to retrofits.

As indicated in Figure 6a, the cost of CO_2 abatement for retrofits is hardly affected by the efficiency of the original plant. The intrinsic effects of the efficiency of the existing plant on the cost of CO_2 abatement ($/tonne) will cancel out; less efficient plants have to capture more CO_2 and take a proportionally higher loss in net plant electricity output but the quantity of CO_2 emissions avoided by a plant with CCS compared to the original plant are higher and hence the cost of reducing CO_2 emissions by retrofitting CCS is not affected by power plant efficiency (although it is likely to be affected by other factors that may differ between sites). The cost of abatement for <u>replacing</u> an existing plant with a new build plant with CCS is, however, a strong function of the existing plant efficiency.



(a) (b)

Figure 6 **Effect of plant efficiency on (a) cost of abatement and (b) levelised cost of electricity without CO_2 emission charges for coal plant retrofits and new coal with CCS**

In principle as carbon prices are raised the first (i.e. lowest cost) emission reductions might be obtained by replacing very low efficiency existing plants by new build plants with CCS. Above a certain efficiency level, however, where replacement became unattractive, retrofit would be almost equally attractive on all existing plants, or more accurately efficiency would have little or no inherent effect on the choice of subsequent retrofits as the carbon price was raised. Instead other, site specific factors, would determine the relative economics of paying for carbon emissions or avoiding payment by retrofitting CCS.

Finally, new-build plants with CCS are typically expected to have higher efficiencies than retrofitted plants (e.g. due to higher temperature/pressure steam conditions in the power plant steam cycle and/or improved gas turbine technology for natural gas combined cycle plants), which will result in lower short run marginal operating costs. Because the dispatch of power plants usually depends on their short run marginal operating costs, new-build plants may operate for more hours in a year than retrofitted plants. The report shows that the benefit of this will be much lower than a simplistic (and incorrect) application of load factors in levelised cost of electricity calculations would suggest, since electricity prices must be reduced to levels where even new build plants will not recover much more than their marginal costs if other plants burning the same fuel are constrained off by electricity prices.

Potential scope for CCS retrofits

As part of this study, a preliminary assessment of the potential for CCS retrofit at Chinese power plants was undertaken based on Google Earth and Google Map images. Published assessments of the potential in the USA and UK based on similar techniques were also reviewed. In these countries there appears to be significant potential based on existing sites and, in the case of the UK, the requirement for new plants to be built capture ready. Quantitative results for some aspects of retrofit potential have been produced in all the studies, but quantitative assessment of actual future retrofit deployment is precluded at present because of inadequate data for all three aspects of retrofit potential:

1. technical potential to fit capture equipment,
2. access to CO_2 storage and
3. economic and social viability (including the actual timing for consideration of retrofitting).

This is obviously an area where future work could be useful. Possible improvements might include examination of whether more consistent and less subjective plant image assessment techniques are possible (e.g. based on quantitative image analysis). Comparison with conceptual studies and actual retrofit projects is also becoming increasingly more feasible. Transport and storage aspects will, however, remain difficult pending the development of national CO_2 pipeline infrastructure plans and storage trials to prove capacities and locations.

If more accurate assessments of retrofit potential are required it is however worth noting that the number of possible retrofit sites to cover a significant proportion of national installed capacity, even in large markets such as the USA and China, is still only in the hundreds. National databases covering site-specific retrofit-related characteristics for each individual plant are therefore entirely feasible, and could start with the present studies as a basis. Better information in this area could be of very material assistance, for example for planning CO_2 transport and storage infrastructure or assessing the impact of policy changes, in a period of transition from currently effectively no CCS on power plants to perhaps a time when it becomes the norm under certain circumstances. Such databases should therefore also be updated periodically, as more data on the relevant factors became available. Commercial confidentiality may limit the amount of such information that is made available in the public domain, but it is clearly of strategic importance for governments considering the scope for national CO_2 emissions reductions.

Expert Review Comments

Comments on the draft report were received from reviewers who are actively working on assessment of power plants with CCS from a variety of backgrounds including engineering consultancy, industrial and government R&D and academia.

In general the reviewers pointed out the need for more work on CCS retrofit and they welcomed the contribution of this report. A major theme of the comments was the relative importance of efficiency, cost of electricity and cost of CO_2 abatement in determining the relative merits of retrofit and new build CCS. For example, although the efficiency of the plant to be retrofitted does not per se affect the cost of CO_2 abatement, as stated in the report, a low efficiency could affect the capacity factor of the plant and low efficiency plants tend to be smaller and older, with less residual lifetime and/or higher costs for refurbishment, which are important issues for retrofit economics. These observations led to the explicit identification in the revised report of the greater possibility for replacement by new build to give lower costs than retrofit for lower efficiency plants, as shown in Figure 6 above.

Reviewers emphasised that the decisions that face power generator when they have to reduce greenhouse gas emissions are complex. There are many options other than retrofit or new build CCS and many location-specific criteria will affect decisions about whether or not to retrofit CCS. It was recommended that these issues should be taken into account more, particularly in the conclusions of the report. Changes were made to the report to address these issues as far as possible, and to improve the presentation of information.

Some reviewers also commented on the relatively low default capture plant capital costs assumed in this study. These were compared with a recent IEA review study (see Appendix 7). The default values used for gas turbine combined cycle plants were found to be in line with the ranges presented but the default value of 700 \$/(kgCO_2/hr) used in this study for boiler and steam turbine plant did indeed appear at the low end of the reported range, but an appropriate sensitivity study showed only a small effect on the retrofit vs. new build LCOE balance since both were affected to a similar degree.

Conclusions

- The decisions that face power generators when they have to reduce greenhouse gas emissions are complex. There are many options other than retrofit or new build CCS and many location-specific criteria will affect decisions about whether or not to retrofit CCS.

- For a range of conditions that might be encountered in practice it appears that the costs of electricity from power plants retrofitted with CCS may be lower than from new build power plants with CCS. Lower costs of CO_2 capture at new build power plants compared to retrofits may be offset by the higher capital cost of the base power plant itself, even if some level of refurbishment to the base power plant is required to achieve an adequate retrofit project life.

- For new power plants that are being built now, which will be the existing plants of the future, concerns about plant life after retrofit are reduced. Additionally, concerns about unduly high retrofit costs should be avoided if current new power plants are built capture ready.

- CCS retrofits to plants with lower efficiencies will tend to have higher generation costs and so are generally less likely to be competitive with new build CCS replacements, but the strong effect of other site-specific factors on retrofit generation costs makes a definite minimum efficiency threshold for retrofitting inappropriate. Costs of abatement (\$/t CO_2) for retrofits are essentially independent of the original plant efficiency, since changes in generation costs with efficiency are balanced by changes in carbon emission reduction.

- A wide range of theoretical options exist for effective integration of post-combustion and oxyfuel capture equipment with the steam cycles of existing coal and gas power plants, which would result in electricity output penalties per tonne of CO_2 captured that are close to those for new build plants using the same capture technology.

- If the electricity output of the plant site is to be maintained after retrofit then additional fuel should be used in ways that deliver as much electricity as possible consistent with the need also to provide heat for the capture plant (i.e. natural gas turbine combined cycle CHP (combined heat and power) or coal-fired high-pressure steam CHP plants). Unless a large increase in power output is required, for post combustion capture it is most effective to combine a CHP plant with some steam extraction from the main steam turbine. As a specific example of the above, while natural gas prices remain attractive it may be advantageous to use relatively small natural gas combined cycle units to make up the power loss and then to meet any heat requirements for a post-combustion capture unit partly by using heat from the new combined cycle plant and partly by extracting steam from the existing steam turbine.

- Surveys of existing plants using Google Earth/Map images in the USA, China and the UK suggest significant numbers of sites exist with space to add capture equipment and likely access to storage, although a number of uncertainties remain to be resolved and further work is required in this area.

- The overall conclusion arising from this work is that retrofitting CCS to existing power plants is worth examining objectively as an alternative to closing down existing plants and replacing them with new build plants, when a reduction in CO_2 emissions from an existing fossil power plant fleet is required. A general rejection of retrofitting on grounds such as the age or lower efficiency of existing plants is not justified.

Recommendations

- The initial national surveys of retrofit-related characteristics of existing power plants reported in this study could be extended as ongoing reference databases covering more countries. These could be upgraded on an on-going basis by detailed data from site-specific engineering studies that might be carried out and by the addition of further data on other relevant factors such as location and capacity of CO_2 storage.

Retrofitting CO_2 capture to existing power plants: effects of retrofit configuration and project technical and economic parameters on levelised electricity costs

Jon Gibbins[1,*], Hannah Chalmers[1], Mathieu Lucquiaud[1],
Niall McGlashan[2], Jia Li[2] and Xi Liang[3]

[1]School of Engineering, University of Edinburgh, UK

[2]Mechanical Engineering Department, Imperial College London, UK

[3]College of Life and Environmental Sciences, University of Exeter, UK

*Corresponding author: jon.gibbins@ed.ac.uk, +44(0)7812 901244

CONTENTS

List of acronyms

bar	unit of pressure
bara	bar absolute (unit of pressure)
BTU	British thermal unit (unit of energy)
CCGT	Combined cycle gas turbine
CCPC	Canadian Clean Power Coalition
CCR	CO_2 capture ready
CCS	Carbon capture and storage
CCSR	CO_2 capture and storage ready
CHP	Combined heat and power
CO_2	Carbon dioxide
COE	Cost of electricity
COPx	Coefficient of Performance for steam extraction (see section 5.2.3)
EGR	Exhaust gas recirculation
EOP	Electricity output penalty
EUF	Energy utilisation factor
FGD	Flue gas desulphurisation
G8	Group of Eight
GIS	Geographic information system
GJ_{th}	Gigajoules of thermal energy (unit of energy)
GW	Gigawatt (unit of power)
Hg	Mercury
HHV	Higher heating value
HP	High pressure (steam turbine or superheater)
HRSG	Heat recovery steam generator
IEA	International Energy Agency
IEAGHG	International Energy Agency Greenhouse Gas R&D Programme
IGCC	Integrated gasification combined cycle (type of power plant)
IP	Intermediate pressure (steam turbine)
IPCC	Intergovernmental Panel on Climate Change
km	kilometre (unit of length)
KS1	Proprietary solvent developed by Mitsubishi Heavy Industries
kWh	kilowatt-hour (unit of energy)
LF	Load factor
LHV	Lower heating value
LP	Low pressure (steam turbine or economizer)
MEA	Monoethanolamine
MW	megawatt (unit of power)
NETL	National Energy Technology Laboratory (in USA)
NGCC	Natural gas combined cycle (type of power plant)
NOx	Oxides of nitrogen (combustion products)
PC	Pulverised coal (type of power plant)
PCC	Post-combustion capture (type of CO_2 capture technology)
SCGT	Semi-closed gas turbine
SO_2	Sulphur dioxide
SOx	Oxides (combustion products) of sulphur
tCO_2	tonne of CO_2
US	United States of America

1 Introduction

Carbon capture and storage (CCS) is often identified as an important technology for mitigating global carbon dioxide (CO_2) emissions. For example, the 2009 International Energy Agency CCS Roadmap (IEA, 2009) suggests that nearly 1000 CCS projects (around half of them on power plants) may need to be operational globally by 2030 as part of action to approximately halve the rate of greenhouse gas emissions by 2050. Since global rollout of proven CCS technologies on power plants is not expected to commence until 2020 at the earliest this represents a very challenging build rate, as illustrated in Figure 1.1.

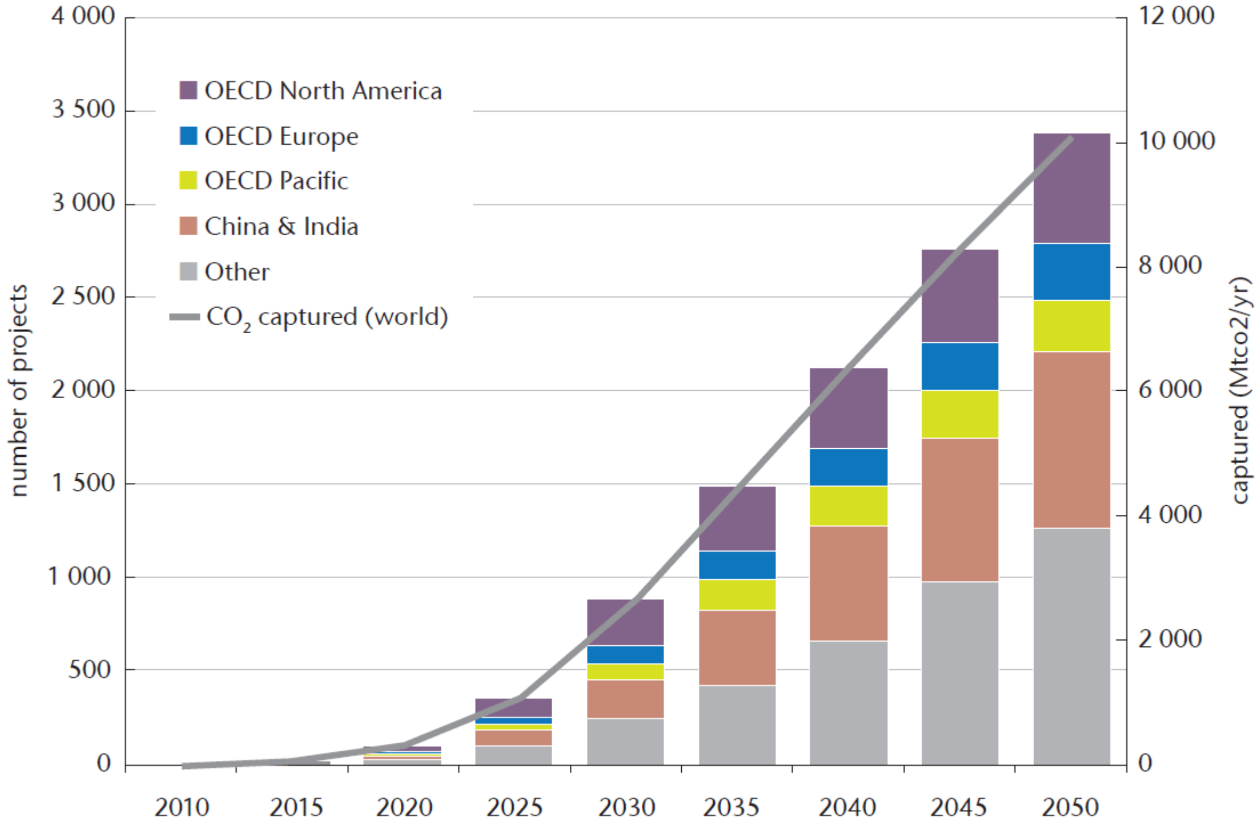


Figure 1.1 CCS deployment estimates from the IEA CCS Roadmap (IEA, 2009)
(Based on a build-up over time to the amount of CCS included in the 2050 global energy mix that was used to achieve a 50% reduction in CO_2 emissions in the IEA BLUE scenario. As with all projections into the future the trends shown for the number of CCS projects are based on uncertain estimates, have interdependencies with many other aspects of the global energy system and could be either higher or lower than indicated. For further details the reader should refer to the original document and also to the extensive body of work by the IEA on global energy system analysis of which this is a part.)

In this context, it seems very likely that some retrofit of CO_2 capture to existing plant could make a valuable contribution to global CO_2 emissions reduction. In particular, retrofits to the existing fleet are a potentially effective way to address the problem that an absolute reduction in CO_2 emissions from fossil fuel use cannot be achieved by new build plants alone. For such a reduction to occur it is also necessary for existing plants to reduce their CO_2 emission levels or close (or have their operating hours significantly reduced). Additionally, a retrofit programme for CCS rollout should require less construction activity since fewer new power plants are required (although some may be needed if plant outputs are reduced retrofitting) and so can allow CO_2 capture to be deployed more quickly than would be possible if new plants must be built before any CO_2 capture can be implemented. It is also worth noting that retrofitting CCS on existing coal power plants can lead to significant reductions in traditional air emissions such as SOx, NOx, Hg and fine particulates. While any increase in coal use due to lower efficiencies with CCS may result in greater off-site environmental emissions from the coal supply system there is a strong possibility of a net overall emissions reduction from CCS retrofits, especially if the original existing coal unit had limited SO_2 or NOx emission controls[1].

Although regulators in some jurisdictions are already requiring that power plants constructed from now until CCS is routinely implemented should be 'capture ready', the currently existing fleet of power plants worldwide has not been designed to be suitable for retrofit of CO_2 capture. It is expected that much of this fleet could operate for at least several more decades, so it is necessary to understand particular challenges that may be faced by utilities and investors considering a retrofit project for a plant that was not designed to be capture ready, as well as for capture ready plants, as part of any attempt to estimate the global potential for CO_2 capture retrofit to contribute to significant reductions in CO_2 emissions. While the regulations and market forces that drive such a change will obviously vary between different countries and/or electricity markets, and equipment, fuel and other costs will also vary with place and time, some general similarities in the range of options associated with potential power plant CCS retrofit decisions and the factors affecting their technical and economic viability can be expected to exist.

The main purpose of this report is to examine, at a generic level, the scope for cutting CO_2 emissions from suitable existing fossil fuel plants by retrofitting CCS to them, as an alternative to replacing them with new build fossil fuel plants with CCS. In this context it should be seen as a discussion of preliminary screening assessment methods to address the general issue of 'under what conditions might it be worth considering retrofitting CCS to an existing fossil power plant, instead of replacing it by a new plant with CCS'? As a generic study though it cannot address either future costs for construction, fuel etc. or site- and region-specific questions that will govern the feasibility and cost of a specific retrofit project, although it does discuss some of the principles involved and examine sensitivities. Nor does it make comparisons with other options for emission reductions from a particular site, such as fuel switching from coal to gas.

The most important principle when making a comparison of retrofit and new build options for reducing CO_2 emissions from existing plants is that a consistent and correct baseline is used for all cases, particularly when presenting the relative costs per tonne of CO_2 avoided/abated. Errors in this respect have arguably been the most serious barrier to both a proper assessment of the potential of CCS retrofits and also an understanding of the incentives required to reduce CO_2 emissions from existing power plants.

In particular, if the alternative to retrofitting an existing plant is to close it down and replace it with a new generation source then, even if it is not yet formally written off, the effective capital cost, for decision-making purposes, of providing the as-is existing plant is zero[2], although the additional costs for any refurbishment (and subsequent maintenance) to give the necessary further operating life will also need to be considered. This reduced effective capital cost means that levelised electricity costs for an existing plant without capture may be lower than for a new build fossil power plant without capture.

[1] The authors are grateful to Dale Simbeck for drawing attention to the possibility of these co-benefits for other environmental emissions.

[2] If the plant is otherwise to be closed, then strictly the 'capital' cost of keeping it open will be the scrap value less the decommissioning costs, although these are often assumed to be comparable.

Additionally, the potential scope for CCS retrofits as assessed by published (preliminary) assessments in three key markets (the USA, China and the EU) is considered, in the context of contributing to rapid CCS rollout in the 2020s. One key issue is the extent to which new gas, rather than coal, capacity is constructed over the next decade in developed economies such as the USA and western Europe and, if so, whether the economic advantage for gas persists[3]. The scope for plant refurbishment for life extension is also important in these markets, particularly in the USA. Preliminary work by US experts reviewing CCS retrofits (Simbeck, 2009) suggests that even with significant refurbishing and upgrading retrofit project costs may still be competitive with new build coal plants.

Similar reviews for space on site and plant location in relation to access to storage have been conducted in the USA, China and the UK using Google Earth and Google Map images. These all suggest significant numbers of coal (USA and China) and natural gas (UK) plants may be suitable for retrofit in respect of these two criteria, although more uncertainty exists for the Chinese power plants study. Ways of building on this early work are discussed.

The report also contains, by way of an introduction to the technical and economic analyses it presents, a review of the literature on CCS retrofits published since the IPCC review of CCS in 2005.

[3] Low natural gas prices will, of course, probably tend to rise if they encourage the more widespread use of gas in power generation. Power plant investors clearly need to take a fairly long-term view of fuel price trends and also face the possibility that their decisions, individually or collectively, may even affect local or regional fuel markets.

2 Literature review on CO_2 capture retrofit

Although much of the literature on CCS addresses new build power plants that have CO_2 capture installed at the outset, there is also some literature on retrofitting CO_2 capture to existing plants. The 2005 Intergovernmental Panel on Climate Change (IPCC, 2005) special report on CCS summarises the main conclusions from early literature on retrofitting CCS to existing power plants. This section provides a brief overview of the development of the literature on CO_2 capture retrofits before the IPCC (2005) special report and then outlines a range of more recent contributions in this area.

The review presented here is not exhaustive, but it does draw from a comprehensive cross-section of the literature. This broad scope is important since the combined influence of insights offered by different types of study are relevant for understanding the basis for 'established truths' that emerged in the discourse on retrofit analysis, including in the IPCC (2005) special report. It is also necessary for exploring whether the initial consensus that developed around 2005 is valid for different investors making decisions about the technical and economic viability of retrofit projects in a range of jurisdictions at the time of writing and in the future.

2.1 Overview of some early literature: up to IPCC (2005)

Although the literature on CO_2 capture retrofit is more limited than on CO_2 capture generally, a range of early contributions (i.e. published before the 2005 IPCC special report on CCS) can be identified. There is generally very little literature on CCS for power plants burning natural gas and no relevant references before 2005 have been identified by the authors. A comprehensive study on retrofit options for natural gas-fired combined cycle power plants was, however, commissioned by IEAGHG in 2005 (IEAGHG, 2005). As in the rest of this report, retrofits to IGCC plants are generally not considered in this review due to the very limited numbers of IGCC plants in the existing fleet and the likelihood at present that the majority of new IGCC plants built will have CCS fitted from the outset. This Section, therefore, focuses on retrofitting CO_2 capture to pulverised coal-fired power plants.

2.1.1 Beginnings: pre-2004

One example of an early contribution to the CCS techno-economic literature is an analysis of retrofit options for existing coal-fired power plants presented by SFA Pacific at the 5th International Conference on Greenhouse Gas Control Technologies (Simbeck and McDonald, 2000). This work used "standardized and summarized" results based on two detailed site-specific studies carried out for TransAlta on amine-based post-combustion capture and an oxyfuel plant, complemented by additional options developed by SFA Pacific. It concluded that retrofitting CO_2 capture to existing coal plants could be cost competitive. The authors noted, however, that the value associated with the captured CO_2 (e.g. for sale for Enhanced Oil Recovery – EOR) will be critical in determining the economic feasibility of any particular project.

The US Department of Energy also commissioned work on the engineering and economic feasibility of CO_2 capture at an existing coal plant several years before the 2005 IPCC special report (Bozzuto et al, 2001). This was intended as a comprehensive study that could provide useful input to US electric utility decision-making on greenhouse gas reduction measures. Three retrofit concepts (two post-combustion and one oxyfuel) were explored and no major technical barriers to retrofit were identified for any of these options. A later study (Ramezan et al, 2007) updated this original study and the results are discussed further in Section 2.2 (Box 2.3).

Finally, another noteworthy contribution in the pre-2004 literature was made by Rao and Rubin (2002). They presented the approach used for the first CO_2 module developed for the Integrated Environmental Control Model (IECM, http://www.iecm-online.com/). Quantitative examples for both new-build and retrofit use of a post-combustion capture process using MEA (monoethanolamine) were considered and it is concluded that:

> *"The cost of carbon avoidance was shown to depend strongly on assumptions about the reference plant design, details of the CO_2 capture system design, interactions with other pollution control systems, and method of CO_2 storage. The CO_2 avoidance cost for retrofit systems was found to be generally higher than for new plants, mainly because of the higher energy penalty resulting from less efficient heat integration as well as site-specific difficulties typically encountered in retrofit applications."*

They also noted, however, that amortized capital associated with a base power plant that could be retrofitted with CO_2 capture is potentially significant. In particular, they considered a quantitative example where a 25% increase in capital costs for CO_2 capture equipment installation in a retrofit application is assumed, but the base power plant is already fully amortized. For this example the overall levelised cost of electricity for the retrofitted plant includes only operating and maintenance costs and new capital expenditure for CO_2 capture. The cost saving from being supplied with a 'free' existing base plant is significant and leads to levelised cost of electricity being lower for the retrofit case than a new power plant built with CO_2 capture.

It is also worth noting that in determining the 'cost of carbon avoidance' as stated above Rao and Rubin used two different baselines, a new plant without capture and an existing plant without capture, for the cases of a new plant with capture and the retrofitted plant respectively. This approach is consistent with querying the carbon price associated with two different decisions:

a) Having already decided to build a new plant, what is the carbon abatement value of adding CO_2 capture (baseline, new plant without capture)?

b) What is the carbon abatement value of adding CO_2 capture to an existing plant (baseline, existing plant without capture)?

The questions that were not addressed, although it might be considered that they were, are:

c) What are the costs of abatement for reducing emissions from an existing plant without capture by either retrofitting it with capture or replacing it with a new plant with capture (baseline, existing plant without capture in both cases)? Then the option with the lower levelised cost of electricity will also give the lower cost of abatement – see Section 5.4.

d) What are the costs of abatement for retrofitting CCS to two existing plants, one with a lower efficiency (baseline, that lower efficiency plant) and one with a higher efficiency (baseline, that higher efficiency plant)? In this case both plants are existing, so no significant differences between the two cases are expected due to base plant capital investments if refurbishment requirements associated with any extended operation with CO_2 capture are independent of efficiency. Additionally, if both plants have access to the same electricity market they can typically be expected to receive the same electricity prices before and after CCS retrofit (in an open market this will be irrespective of their generation costs) and it can then be shown that their costs of abatement for retrofitting are the same and are independent of base plant efficiency – see Section 5.1. (The cost of abatement for replacement with a new build plant with CCS will, however, be lower for the lower efficiency plant, and therefore is more likely to be lower than the (common) cost of abatement for retrofitting – this is essentially equivalent to the levelised cost of electricity for the new build CCS plant being lower than for the retrofitted plant).

2.1.2 Academic literature and early landmark studies: 2004

Following the initial indications that retrofit of CO_2 capture to existing power plants could be technically and economically feasible at some sites, a few groups within the academic community explored the concept of CO_2 capture retrofit further. For example, at the University of Waterloo Alie (2004) undertook an initial engineering analysis of the potential to integrate an MEA post-combustion capture (PCC) process with an existing coal-fired power plant steam cycle and concluded that "it is clear that there is a substantial thermodynamic advantage to diverting low-pressure steam from the steam cycle for use in the CO_2 capture plant", rather than using an auxiliary boiler to provide heat for regenerating solvent within the PCC process. This is consistent with more general work on principles for power plant design with PCC, including as reported by Gibbins and others (Gibbins et al, 2004a; Gibbins and Crane, 2004b), which is discussed further in Section 3.2.

One notable contribution to the economic literature was made by Johnson and Keith (2004). They used a model of electricity system dispatch decisions[4] to explore the importance of a number of factors, including the option to retrofit PCC to existing plants, in determining costs of CO_2 emissions abatement. They found that CO_2 capture retrofits were not economic in their baseline case, probably due to the CO_2 and fuel price combination assumed, and concluded that the economic viability of retrofitting CO_2 capture to existing plants depends on retrofit costs and plant efficiency after retrofit (which depends on both base power plant efficiency and the electricity output penalty associated with using CO_2 capture). Additionally, they demonstrated that changes in the use of power plants fitted with CO_2 capture are not necessarily linear with changes in these factors. This is to be expected since electricity systems can contain a number of plants with similar operating costs (with these costs typically having a significant influence in determining which plants are used to meet electricity demand). As performance or costs change there will only be variations in plant dispatch if the competiveness of plants retrofitted with CO_2 capture when compared to other options for generating electricity (or reducing electricity demand) is altered.

Alongside analysis undertaken by the academic community a number of major, often industry-led, studies also appear to have played a significant role in shaping the dominant view on the viability of retrofit of CO_2 capture to power plants (and other large industrial sources) that was emerging by the middle of the first decade of the 21st century. For example, the first phase of the Carbon Capture Project used a retrofit example – in this case at a refinery – in its analysis to illustrate baseline technology costs (Simmonds et al, 2002; Switzer et al, 2005). A significant analysis of retrofit to coal fired power plants was also undertaken by the Canadian Clean Power Coalition, with non-confidential results reported in IEAGHG (2004a) and summarised in Box 2.1. Although studies continued to suggest that CO_2 capture retrofits could be technically feasible, significant concerns about the economic viability of these projects were typically identified.

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[4] Electricity system dispatch decisions are the choices made by electricity system operators about which power plants will be used to supply electricity demand. A number of factors are typically taken into account, including the short run costs of electricity generation at each plant and the need to provide back-up (ancillary) services for security and quality of electricity supply. See standard texts such as Kirschen and Strbac (2004) for a more detailed introduction.

Box 2.1
Canadian Clean Power Coalition studies on retrofitting CO_2 capture to existing power plants
The founding members of the Canadian Clean Power Coalition (CCPC) were seven electric utilities in Canada. They were subsequently joined by the Electric Power Research Institute (EPRI), IEAGHG and the IEA Clean Coal Centre. The first phase of CCPC work focussed on conceptual studies to determine which technologies, fuels and storage sites might be suitable and available for CCS demonstration projects. Plants were deliberately designed for particular Canadian power plant locations, so it is important to note the costs obtained include a number of site-specific factors.

CCPC considered both new-build and retrofit applications of CO_2 capture to coal-fired power plants, with three different Canadian coals (Nova Scotia bituminous, Albertan sub-bituminous and Saskatchewan lignite). Although it was intended that PCC using amine scrubbing and oxyfuel technologies would be assessed as retrofit technologies, initial results suggested that, for the retrofit configurations assumed, performance of these options would be relatively poor in retrofit situations so the later stages of the analysis focussed on new-build applications.

An important feature of the initial phases of the CCPC work is that there was a requirement for no net loss of power sent out due to CO_2 capture retrofit. It was assumed that additional power would be generated on-site and that auxiliary boilers, with an associated significant reduction in efficiency, would be used. The value of integration between a PCC plant and base power plant was identified, but it was noted that this integration would be more difficult to achieve for a retrofit application than at a new build site. For oxyfuel plants, the potential for air infiltration to increase the concentration of inert gases in the flue gas with an associated increase in the cost of CO_2 compression and processing was identified as a significant concern. It was also decided that the energy penalty for retrofitting CO_2 capture implied that a high efficiency power cycle was necessary.

Although an oxyfuel retrofit case was not pursued beyond the initial evaluation stage, a more detailed comparison of PCC for new-build or retrofit was made, although without an auxiliary boiler to provide make-up power since the technical committee guiding the work recognised that “its requirements around the supply of auxiliary power to the plant [were] causing significant compromises in the design”. Since the study assumed an improvement in steam parameters for the new-build plant, it is difficult to judge how important any limitations in achieving good integration between the PCC plant and base power plant were in the plant designs developed by Fluor for CCPC. The analysis did show, however, that the assumed source of make-up power when a plant is retrofitted with CO_2 capture can have a significant influence on both costs and CO_2 emissions associated with a CCS project.

Overall, the first phase of CCPC analysis suggested that retrofit will only be attractive if all new plants are already being fitted with CO_2 capture and further emissions reductions are still required. The importance of design optimisation and ability to achieve good integration were also highlighted.

Source: IEAGHG (2004)

2.1.3 IPCC Special Report perspectives on retrofits: 2005

In 2005 the Intergovernmental Panel on Climate Change published a special report on CCS (IPCC, 2005) that provided an authoritative review of the consensus on state-of-the-art understanding of technology and economics at the time. It noted that retrofitting existing power plants with CO_2 capture had not been “extensively studied” but that the limited literature available suggested that retrofitting PCC would lead to increased efficiency loss and higher costs than those expected for new-build sites. Additionally, this limited literature was typically suggesting that economic performance would be improved by rebuilding the boiler and turbine at the same time as retrofitting CO_2 capture to coal-fired power plants. The potential to repower sites with an IGCC plant including CO_2 capture was also identified, although no “systematic comparison of the feasibility and cost of alternative retrofit and repowering options for existing plants” was available at the time of writing.

Although a number of disadvantages associated with retrofit projects were identified in IPCC (2005), the potential need to retrofit existing plants so that any rapid introduction of CO_2 capture would not mean that existing plants “have to be retired prematurely and replaced by new plants with capture" was also acknowledged. These concerns included the lower efficiencies of typical existing plants and site-specific difficulties with locating and integrating a capture plant with an existing base power plant. Despite this, it was also noted that:

> "*In cases where the capital cost of the existing plant has been fully or substantially amortized,... the COE [cost of electricity] of a retrofitted plant with capture (including all new capital requirements) can be comparable to or lower than that of a new plant, although the incremental COE is typically higher..."*

2.2 Insights after IPCC: 2005-2007

Since the consensus view illustrated in the IPCC (2005) special report on CCS was that economics would be challenging for cases where CO_2 capture was retrofitted to existing plants, partly due to low base plant efficiencies, work for the next few years tended to focus on retrofit to supercritical coal-fired plants or extensive retrofits (i.e. including upgrading of boilers and turbines) for existing plants with sub-critical steam cycles. Additionally, a number of researchers chose to focus on the potential for new plants to be built 'CO_2 capture ready' (CCR) so that many of the challenges associated with retrofitting existing plants that were not designed with CO_2 capture retrofit in mind could be avoided.

Since it is expected that CCR plants will be retrofitted and this phase of plant life was considered in many studies, some insights for retrofit to existing plants can be gained from CCR work for evaluating retrofits to existing plants. Despite the dominant view established around 2005, a few authors did continue to publish work on retrofits to existing plants without a boiler/turbine upgrade and some examples of conclusions made in these papers and reports are also included in this sub-section. As in the earlier literature, there is little or no consideration of retrofits for power plants burning natural gas, biomass or other fuels in the period immediately after IPCC (2005) was published, so these options are not discussed here.

2.2.1 CCR retrofits and supercritical plants

Two industry-led studies that were undertaken during this period and that provided a range of useful insights were a study on advanced supercritical boiler/turbine retrofits (i.e. rebuilding an existing sub-critical boiler and steam turbine for supercritical steam conditions) with CO_2 capture to existing coal-fired power plants in the UK (Panesar et al, 2007) and a review of CO_2 capture options for the Canadian market (Xu et al, 2007). A summary of some of the key conclusions from Panesar et al (2007) is included in Box 2.2.

Although the majority of the analysis carried out by Xu et al (2007) focussed on new-build supercritical coal-fired plants, some illustrative CO_2 capture retrofit cases were also considered, where CO_2 capture was fitted some time after an advanced supercritical boiler had been built. This work suggested that electricity output penalties associated with retrofits can be no more than 1 percentage point worse than those observed for plants built with CO_2 capture when they are initially constructed. In the PCC case, the retrofit example was assumed to retain the main steam cycle condenser with the same cooling water mass flow rate following retrofit, leading to a lower condenser pressure and, hence, improved performance when compared to an equivalent new-build plant. This design decision would, however, then require that an additional auxiliary cooling water system is installed for use by the retrofitted CO_2 capture plant and possibly introduce some risk of problems with wet steam in the final stages of the LP turbine. By contrast, an increase in condenser temperature was observed in the oxyfuel case due to the same assumed constant condenser cooling water mass flow. More heat is rejected in the main steam/water cycle of an oxyfuel power plant than for a base power plant without CO_2 capture or fitted with PCC. This is because condensate heating is replaced by heat recovery from the capture processes with a consequent increase in the steam flow at the exit from the low pressure turbine. Xu et al (2007) noted that it should, therefore, be possible to avoid much of the increased electrical output penalty for an oxyfuel retrofit (when compared to a new-build oxyfuel plant) suggested in their work by increasing the capacity of the cooling system.

Box 2.2
Advanced supercritical retrofit with CO_2 capture to existing UK coal power plants (Project DTI407)
The work undertaken in this project aimed to assess technical and economic feasibility of retrofitting both advanced supercritical boiler technology (290bara/600°C/620°C) and CO_2 capture to the UK coal-fired fleet. It used a reference power plant and two alternative sites to allow both a relatively detailed evaluation of one site and an understanding of variations due to site-specific considerations to be obtained. Amine-based PCC and oxyfuel approaches were evaluated using conceptual designs that provided sufficient detail for a scope of supply to guide costing to be developed and also for site plans with capture equipment footprint added to be established. Additionally, programme and schedule requirements, including consideration of site specific constraints and permitting, were identified.

The project partners demonstrated that it is technically feasible to retrofit amine-based PCC or oxyfuel technology to existing plants in combination with an advanced supercritical boiler/turbine retrofit and that these options could be economically viable. In fact, they suggested that:

"when CO_2 capture and storage becomes economic or mandatory the retrofit routes studied are likely to be amongst the best and most economic options for existing pulverised fuel power generation plant."

It should be noted, however, that they also concluded that it was likely that most existing UK power plant sites would have insufficient space and cooling capacity available to apply capture equipment to all existing installed units. An initial assessment of expected reliability, availability and maintainability (RAM) suggested that reasonable performance in this area could be expected once CO_2 capture technology has matured, particularly if the CO_2 capture can be bypassed if it fails.

Since the project partners did not carry out detailed assessments of CO_2 capture retrofit without an advanced boiler/turbine retrofit, the only programme estimate available from this study includes a significant outage including the boiler/turbine replacement. A total retrofit programme duration (from contract award to return to commercial operation) of 56-58 months was estimated, with an outage of around 2 years for intrusive works (from unit off-line to unit return to service). The inclusion of CO_2 capture within the programme of work was not expected to have a significant impact on the time taken for the whole retrofit project to be completed. It is important to note, however, that adding CO_2 capture is likely to require additional planning consents, e.g. related to health and safety requirements for additional processes and chemicals that are required on-site.

Source: Panesar et al (2007)

The most substantial technical public domain study undertaken on CCR during this period was commissioned by IEAGHG as part of the G8 Gleneagles programme of action (IEAGHG, 2007). Studies such as this are useful for understanding some of the key engineering challenges that may be faced by plant operators retrofitting non-CCR plants since they highlight measures that may be taken to make later CO_2 capture retrofit easier at plants that are built without CO_2 capture installed initially, but with the intention that any technical barriers to CO_2 capture retrofit have been identified and removed from plant designs before they are constructed. It is important to note that although CCR plants are specifically designed with the potential for later retrofit of CO_2 capture in mind, it is also possible that existing plants will still happen to have some or all of the features that are explicitly included in CCR designs. The key distinction is that there was originally no deliberate intent to remove barriers to CO_2 capture retrofit at non-CCR existing plants.

An intermediate suggestion by Figueroa and Plasynski (2007) was that opportunities from plant outages, equipment replacement etc. could be used to modify suitable existing power plants so that they better meet CCR criteria. Since generation output that is lost while a plant is modified to retrofit capture could represent a significant cost barrier to retrofit, the use of 'free' time during earlier outages could achieve significant cost savings. Obviously some types of deficiency in some original designs will not be able to be rectified subsequently, but provided a finally modified plant adequately meets CCR criteria it might functionally be close in its potential for retrofit to a new-build CCR plant. The up-front costs of these advance CCR modifications could, it was implicitly suggested, achieve immediate payback in terms of a better-defined cap on the plant owner's future liability to CO_2 emissions charges.

Two important sets of factors that must be considered in CCR design that were identified in IEAGHG (2007) are the availability of credible routes to CO_2 storage and identifying sufficient space on site. This latter requirement includes access to critical locations during construction and for tie-ins to existing equipment that are helpful or necessary to improve plant efficiency with CO_2 capture (via improved thermodynamic integration) or to reduce the costs of retrofit. These are relevant in analysing the technical and economic feasibility of retrofit to an existing plant that was not designed to be CCR. Space for supporting infrastructure (e.g. cooling water and electrical systems) and safety barrier zones must be considered in addition to the footprint of the CO_2 capture equipment itself.

IEAGHG (2007) also considered the economic performance of CCR plants and the global application of CCR principles and noted that:

> *"In summary, there are a large number of region-specific costs that will determine the relative economics of different power plant configurations and these will all need to be considered when considering the attractiveness of pre-investment options beyond essential capture-ready requirements, to enhance a plant's capture-readiness."*

These region-specific differences (i.e. a tendency for there to be a common approach to plant design across a region, which may differ from the common trends in other regions, due to different sets of economic, regulatory and technical drivers, and perhaps also depending on the periods when the plants were constructed) could also affect general characteristics of different existing non-CCR fleets tending to make them more or less suitable for CO_2 capture retrofit. Additionally, potential improvements in capture technology that could affect what compromises are made when a CCR plant is designed are identified as a critical consideration. A parallel IEAGHG study is exploring the potential for upgradability of coal-fired power plants with PCC as solvents develop and discusses this in more detail (IEAGHG, 2011).

Alongside the technical literature published soon after IPCC (2005), but somewhat independent from it, economic literature on CCS also continued to develop. One interesting contribution to this literature for understanding decisions made by power plant owners and investors when faced with the option to retrofit an existing power plant with CO_2 capture was made by Reinelt and Keith (2005). They developed a stochastic dynamic programming model to analyse decisions taken by firms to minimise the expected present value of costs of electricity generation with uncertain natural gas and CO_2 prices. Their framework considers a number of 'real options'[5] available to

[5] Real options analysis draws on techniques developed in financial economics to value different options that are traded in financial markets. For example, Reinelt and Keith (2005) include options to delay investment, make an investment in a range of technologies, purchase an option for later cost-effective retrofit, actually

investors including the potential to deliberately invest in a plant that is suitable for later retrofit of CO_2 capture, but that does not have CO_2 capture installed when it is initially constructed. They concluded that the availability of managerial flexibility to retrofit CO_2 capture to new build plants has a "substantial impact on social costs" of CO_2 emissions abatement, but they did not consider the potential for existing plants to be retrofitted with CO_2 capture.

IEA (2007) also analysed retrofit to a new-build plant using a real options approach. This study explicitly assumed that plant is built CCR and that "there is not a major cost penalty incurred by investing [in CO_2 capture] subsequently as a retrofit rather than in a single investment [with power plant and CO_2 capture built at the same time]". It showed that the option to retrofit can increase the likelihood of investment in a coal-fired power plant since investment risk is reduced when investors are not locked-in to high CO_2 emissions, even if measures to significantly reduce CO_2 emissions are introduced by regulators. A less clear conclusion is made for natural gas-fired plants since it is assumed that electricity price is closely linked to the operating costs of combined cycle gas turbine plants in this work.

2.2.2 Retrofits to existing plants with sub-critical steam conditions

The IPCC (2005) special report noted that the literature had tended to suggest that CO_2 capture retrofits were likely to be combined with application of supercritical boiler/turbine technology, but a few studies did continue to explore the potential to retrofit CO_2 capture to sub-critical plants without a boiler/turbine upgrade. The most substantial contribution in this area was probably made by Ramezan et al (2007), as discussed in Box 2.3 on the next page, although a few other papers, including as outlined below, can also be identified.

Ploumen (2006) provided a summary of results from baseline studies on electricity production with PCC that were carried out by the Dutch national programme on CCS (http://www.co2-cato.nl/). The importance of a range of factors for implementing a successful retrofit at an existing plant were highlighted including changes to the base power plant steam cycle, operating flexibility of the retrofitted plant, available space for the footprint of the capture plant and identifying appropriate options for increased cooling. Particular attention was given to the steam conditions at the point where steam is extracted from the base power plant cycle to be used for solvent regeneration. This topic is explored in more detail in Chapter 3. It was also noted that improvements in PCC technology could be critical in determining the viability of CO_2 capture retrofit since, for example, "lower energy consumption will reduce the limitations for retrofit like the additional heat disposal via cooling water, and space requirements".

The potential for oxyfuel technology to be applied as a retrofit solution also attracted some attention in papers published during 2007. Karakas et al (2007) reported work undertaken as part of the European ENCAP project (http://www.encapco2.org/). They considered an oxyfuel retrofit design that minimised changes to the base power plant leading to no waste heat integration between the base power plant steam cycle and the capture system and also no changes to heat transfer surfaces in the boiler. This led to a significant increase in the electricity output penalty when compared to the new build plant oxyfuel plant penalty in the same study (12.7% points reduction in efficiency for the retrofit case when compared to a reference power plant without CO_2 capture, compared to around 8.5% points for the new build). This suggests that identifying opportunities for reasonable heat integration will be important for successful retrofit of CO_2 capture

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undertake a retrofit and abandon one technology in favour of another. A good general introduction to such analysis can be found in standard texts such as Schwartz and Trigeorgis (2001).

to existing power plants. Additionally, it should be noted that boiler vendors expect that it should be possible to construct plants that can switch between air and oxygen-firing (e.g. Sekkapan et al, 2007) and this should be considered for any CCR plants where an oxyfuel retrofit may be considered in the future.

Box 2.3
US Department of Energy National Energy Technology Laboratory Conesville studies

Bozzuto et al (2001) and Ramezan et al (2007) are an interesting pair of studies since they illustrate the impact of improvements in knowledge and understanding of PCC technology on conclusions about the viability of retrofitting this technology to power plants. It should also be noted that additional developments that could further improve the performance of a retrofitted power plant could be possible, even when compared to Ramezan et al (2007). This is discussed in Appendix 3.

In both cases, an engineering team led by ALSTOM assessed the potential to retrofit PCC to Unit 5 at Conesville, Ohio. Bozzuto et al (2001) considered two PCC options and also an oxyfuel case. They concluded that the oxyfuel option was favourable for full capture, but that PCC was likely to be better if the capture retrofit was only partial. They recommended, however, that potential improvements in PCC solvents be explored and noted that further work should be undertaken to optimise system performance and fully understand the steam cycle implications of extracting large amounts of steam from the water/steam cycle leading to a significant reduction in steam flow through the low pressure turbine. Areas for improving oxyfuel concepts were also identified.

Ramezan et al (2007) addressed some of these recommendations by exploring the technical and economic feasibility of a range of capture levels for a PCC retrofit (90%, 70%, 50%, 30%) and using an advanced amine-based technology for PCC that could be supplied by Fluor. They concluded that there is an almost linear relationship between the change in capture rate and levelised cost of electricity production in this case. This is attributed primarily to reductions in boiler modification costs (modifications to the flue gas desulphurisation system are required to reduce solvent losses, but it is assumed that no other boiler island modifications are needed) and carbon capture equipment sizes.

This later study also explicitly evaluated the impact of improved solvent performance, including by comparing the results obtained in the 90% case with the post-combustion capture cases in Bozzuto et al (2001). A reduction in solvent regeneration energy of around 1/3 from Bozzuto et al (2001) to state-of-the-art PCC in Ramezan et al (2007) was reported. Ramezan et al (2007) also expected that specific investment costs would be around half of those found by Buzzoto et al (2001). Overall, these factors were expected to lead to a reduction in incremental levelised cost of electricity production (with no CO_2 price considerations) of 43% for retrofitting 90% capture at a coal-fired plant using PCC.

Sources: Ramezan et al (2007), Bozzuto et al (2001)

2.3 Recent Developments: 2008-2010

More recently, the literature on retrofitting CO_2 capture to existing plants has grown significantly as a range of factors have combined to cause many stakeholders to reassess the value of retrofitting to existing plants, both with and without an upgrade to the base power plant. A number of different themes can be identified in the literature as researchers and other stakeholders make contributions to the discourse. This Section summarises some key findings from system-level studies and a high-level expert meeting hosted by MIT in March 2009 (Box 2.4). Insights from more detailed technology-specific studies are summarised in the relevant later sections of this report.

Arguably most importantly, a number of real commercial-scale CCS demonstration projects have been developed as retrofits to existing plants (e.g. Ball, 2008; Doosan Babcock, 2009 and ScottishPower, 2010). A number of analysts, including several contributors to the MIT retrofit symposium outlined in Box 2.4, suggested that even if existing plants are not retrofitted with CO_2 capture they are likely to continue to operate for many years. This conclusion depends on assumed policy measures to mitigate CO_2 emissions (e.g. that a price on CO_2 emissions is applied rather than an emissions performance standard, or some other measure, being introduced at a level that would require CCS). It is also a general reflection of the significant value that can be associated with avoiding, or at least delaying, capital expenditure associated with building a new base power plant if an existing plant can remain in service for longer following a CO_2 capture retrofit.

Chalmers et al (2009) highlighted the potential for retrofit projects such as this to provide a fast-track route to demonstration of PCC and also to facilitate more rapid reductions in CO_2 emissions than would be possible if an effective option for reducing emissions from the existing fleet was not available. This latter point is discussed further in Section 6. It is also illustrated in work reported by Battelle at the Pacific Northwest Lab in the US (Wise et al, 2007; Wise and Dooley, 2009) that used an electric system model to quantify optimal investments in electricity generation, including when generation dispatch (i.e. actual use of installed power plants) is taken into account.

Wise et al (2007) agreed with the conclusions of other literature discussed above that many existing pulverised coal-fired power plants could operate for several decades. They did not, however, consider the potential for PCC (or oxyfuel or other capture technologies such as membranes) retrofit options to be deployed in response to the concerns this raises over continued CO_2 emissions from the existing fleet. Wise and Dooley (2009) extended this analysis to consider what role PCC might play, considering cases with and without technology improvement. The potential for new-build coal-fired power plants with CCS and also retrofit of PCC to already existing coal-fired power plants and also newer plants that do not use CO_2 capture initially was explored for the case study of the Eastern Central Area Reliability Coordination (ECAR) in the US. This later analysis concluded that if climate policy is known well in advance then there may be some use of PCC retrofit to existing plants, but only if technology improvements are seen. Additionally, they reported more significant use of PCC retrofits in a case where future climate policy was not known and observed that:

> *"in perhaps the more likely case that future CO_2 prices are not known, a robust, proven and cost effective PC [pulverised coal] + CCS technology is a hedge that allows new PC capacity to be built and later retrofit and continue to serve as baseload power. The ability to deploy improved PC + CCS technologies also helps to contain the escalation in baseload electricity prices that would be caused by such a rapid increase in CO_2 permit prices and therefore is a means for protecting the larger macro economy if there is a need to rapidly reduce CO_2 emissions."*

Box 2.4
Summary of some key conclusions from MIT retrofit symposium (2009)
In March 2009, the MIT Energy Initiative hosted a symposium on retrofitting of coal-fired power plants for CO_2 emissions reductions. It aimed to "investigate different pathways for CO_2 emissions reductions using current technology, identify promising RD&D for cost reduction, and discuss policy and institutional barriers to CO_2 emissions reductions in the United States" (MIT Energy Initiative, 2009). Fifty four representatives of utilities, academia, government, public interest groups, and industry attended this invitation-only event and discussed a range of themes including those raised by three white papers that were commissioned for the event, as well as a number of additional contributions made by meeting participants.

Many of the conclusions noted in the symposium report (MIT Energy Initiative, 2009) are consistent with other literature. For example, the difficultly of forcing electric utilities to close existing coal-fired power plants was noted and explained:

"owners and operators of coal-fired power plants possess valuable assets above and beyond affordable power. For example, existing coal plants are strategically located on the electric grid transmission system. They have substantial plant infrastructure, hold difficult-to-obtain site and environmental permits, and have access to existing water and coal transportation infrastructures. The value of these assets should not be underestimated when making policy, technology, and investment decisions on mitigating carbon emissions."

In this context, one of the core messages from this symposium was, therefore, that a significant effort would be required so that appropriate retrofit options are available for existing coal fleets. This included a recommendation for a strengthened programme of research, development and demonstration. A range of different approaches to retrofit that could be included within this programme (and rolled out in the short to medium term, in some cases) were identified. These included retrofitting PCC to existing plants and significant rebuilds, potentially including a change in base power plant technology. It was also noted that other measures with lower CO_2 emissions reductions potential could be useful to combine with CO_2 capture (e.g. biomass co-firing, efficiency upgrades).

One significant contribution to improving knowledge on the technical (and economic) details of retrofits to coal-fired power plants is an ongoing study being undertaken by the Electric Power Research Institute (see Specker et al, 2009 for a brief introduction). The importance of including CO_2 capture at gas-fired, as well as coal-fired, power plants was also noted by several symposium participants.

Source: MIT Energy Initiative (2009), http://web.mit.edu/mitei/research/reports.html

2.4 Summary of key points

The concept of retrofitting CO_2 capture to existing power plants is not new, although there has been relatively little consideration of this potential application of CCS in the literature. Initial studies led to the IPCC (2005) special report on CCS conclusion that retrofitting capture was likely to lead to increased efficiency loss and higher costs than those expected for CCS applied at new-build sites. The potential for CO_2 capture retrofit to be a cost-effective approach when it allowed effective use of paid-off base power plant assets was, however, acknowledged (although that zero cost should also be assigned to an existing plant that would otherwise be closed and replaced was apparently not considered).

Subsequent technology developments and work to improve the integration options that might be available for retrofitting CO_2 capture at existing plants has, however, contributed to increasing interest in the potential to retrofit CO_2 capture. Although much of the early literature focussed on PCC it has also been suggested that oxyfuel technologies could be suitable for pulverised coal-fired plant retrofits. This latter option could be most relevant in cases where boilers that are suitable for both air and oxy-firing can be used (e.g. either as a retrofit to a CCR plant or because an advanced boiler/turbine retrofit is combined with the installation of CO_2 capture). It is also possible that other capture technologies (e.g. membranes, solid absorbents) could be retrofitted to existing power plants in the future, although details of such applications have received little attention in the literature to date.

A number of different analytical methods are used in the literature reviewed in this section, with a broad range of factors that could be significant in assessing the technical and economic viability of retrofitting CO_2 capture to existing plants identified. These range from detailed site-specific technology factors such as availability of space for capture plant installation to potentially global considerations on likely CO_2 emissions mitigation policy that could have a significant impact in determining whether or not there is a business case for retrofitting CO_2 capture at existing plants (or installing it as part of new-build power plants).

Later sections of this report will build on the literature reviewed here by developing a parametric performance and economic model that can be used by decision-makers (e.g. project developers and regulators) to explore key sensitivities associated with CO_2 capture retrofit decisions for power plants. The next section will, however, first address some of the more detailed technical issues that must be handled effectively for cost-effective CO_2 capture retrofit design.

3 Technical principles and background for CO_2 capture retrofit to existing plants

When retrofitting CO_2 capture to an existing plant a number of technical issues will need to be considered. While these will be encountered, in some form or another, in most retrofit projects the solutions to many of them will depend to a large extent on specific details of the site and on the characteristics of the plant and the capture process being fitted. At present too few practical studies or projects have been undertaken to draw any conclusions regarding approaches that have been adopted to address these problems (e.g. what worked and what did not etc.) and in many cases the details of these early projects are still largely or wholly confidential for commercial reasons. The scope of work undertaken in this study is, therefore, limited to an examination of the options potentially available for retrofitting capture to existing plants, with a generic assessment of the relative performance and costs for these retrofit options using a parametric approach. Post-combustion capture is used as the example for the majority of this work, but the same approach can also be applied to oxyfuel and other retrofittable capture technologies by specifying appropriate heat and/or power requirements and capital costs. If only electric power is required to operate the capture plant, however, then obviously the drivers for on-site integration and optimisation are much reduced.

Areas where technical considerations must be taken into account in retrofitting CO_2 capture to an existing plant include:

(a) Access to suitable CO_2 storage;
(b) Space on site for additional equipment associated with capture;
(c) Gas cleaning including FGD (flue gas desulphurisation) performance (mainly for coal);
(d) Cooling requirements including identifying space on site for cooling in some cases, water consumption and achievable temperatures;
(e) Meeting the additional electricity and heat needs for the capture-related equipment, including integrating with the main power plant where appropriate;
(f) Identifying a strategy for coping with reduced power output from the site, or maintaining or increasing the exported power (this may include turbine reblading or other upgrades to give efficiency improvements); and
(g) Identifying and addressing any requirements for flexible power plant operation with CCS.

For new build plants that are intentionally designed to be suitable for later retrofit of CO_2 capture, most or all of these factors are considered in 'CO_2 capture ready' (CCR) or 'CCS ready' (CCSR) guidelines for power plants that have been developed by or for a number of organisations including the UK Government Department for Energy and Climate Change (DECC, 2009), IEAGHG (IEAGHG, 2007) and the IEA and Global Carbon Capture and Storage Institute (IEA, 2010). These guidelines give a number of suggestions for managing CCR plant permitting and design in order to achieve a workable outcome and some of these suggestions are also relevant for non-CCR plants that are to be retrofitted with CO_2 capture.

The considerations identified above can be viewed as falling into two categories. Factors (a) to (d) are largely barriers that must be overcome. They may have economic consequences or be show-stoppers. All of them could be resolved by a new plant on an appropriate site, but if the same site is used only marginal improvements may be possible. If the plant is already CCR, and especially if it is also relatively recently built, then in most cases replacement with a new plant would almost certainly not give any great improvement. For an existing non-CCR plant some factors could probably be improved by extensive modifications to the existing plant and/or the partial or complete replacement of various units, but the scope for this and the relative costs must be considered on a project-specific basis.

Factors (e), (f) and (g) principally affect the main function of all power plants, delivering electric power to the grid (electricity network), and hence the economic performance of the retrofit. These factors therefore have generality and will apply irrespective of the site conditions, although not irrespective of the electricity system in which the plant operates.

The principle technical advantages with respect to the energy aspects of a retrofit (increased life, reduced operating costs etc, are taken here as being mainly economic benefits) that building a new plant or rebuilding a base power plant in this situation could potentially offer are:

(i) improved cycle efficiency through more advanced steam conditions, steam turbine blading efficiencies and/or or improved gas turbine efficiencies;
(ii) a steam cycle design optimised for integration with capture; or
(iii) a radical change in plant type such as a different fuel (e.g. gas instead of coal) and/or technology (e.g. IGCC instead of pulverised coal).

The merits of the last benefit depend entirely on expectations of relative fuel prices, plant operating profiles and/or the technoeconomic performance of alternative technologies available at the time and no general answers are currently possible, not least because the necessary experience of the different technical options is lacking. Experience is also very limited for PCC from pulverised coal (PC) or natural gas fired gas turbine combined cycle (GTCC) plant, of course, but because the applications would be so similar it is more feasible to make a relative assessment of the likely merits of retrofitting PCC to an existing plant compared to building a new plant with PCC (or similarly for oxyfuel).

The rest of this section will consider the options available for supplying the heat and power requirements for retrofitting PCC to existing coal and gas power plants, some detailed characteristics of those options and principles for applying them, and the analogous applications for oxyfuel retrofits. Retrofitting capture to integrated gasifier combined cycle (IGCC) plants has not been included explicitly in this study since it currently appears likely that only very limited numbers of IGCC plants will be built without CCS, but many of the principles for other retrofit applications would also apply.

3.1 Range of technical permutations for the retrofit of existing PC or NGCC plant

A range of technical permutations for retrofitting an existing PC or NGCC plant with CO_2 capture arise because an additional plant, essentially a CHP (combined heat and power) plant, can be used to provide some or all of the heat and/or power to run the capture system. This applies to any type of retrofitted capture system, not just PCC.

The use of an additional plant may give several advantages. First of all it can be designed to integrate closely with the capture equipment for the existing plant and for itself (only options which include capture on the additional plant to achieve low overall emissions are being considered, as outlined in more detail in later sections of this report). It will obviously also result in the electrical output from the retrofitted site not falling as far as it would otherwise do, and may also allow it to be increased if this is possible and advantageous.

While a continuum of different levels of heat and power inputs from the existing and additional plants respectively is feasible, a number of obvious break points exist:

(a) Fully-integrated retrofit
All the heat and power required for the capture process is supplied from the existing plant with no additional plant being used. This could apply to PC or GTCC plants.

(b) Boiler heat-matched retrofit
All heat for the capture process is supplied by steam from an external boiler – heat matching. Anecdotal evidence suggests this has been proposed in recent UK CCR discussions in connection with natural gas GTCC plants as the simplest subsequent retrofit solution, since it requires no modification to a conventional steam cycle design. Electrical power is still met from the existing plant. In practice this is likely to be proposed only for natural gas boilers on GTCC plant, since the heat loads for coal plants are very large.

(c) Boiler heat and power matched retrofit
All heat for the capture process is supplied by steam from an external boiler which is fed through a back-pressure turbine to also generate the electrical power needs of the capture process – heat and power matching. The output from the site remains the same (or could increase if grid connection capacity permitted, but then it is more likely that a gas turbine additional power and heat unit would be used). In practice this is also likely to be proposed only for natural gas boilers on GTCC plant.

(d) Gas turbine power matched retrofit
Additional electrical power for the capture process and to cover any loss in power output from the existing plant due to steam extraction is supplied from a CHP plant with the highest possible power to heat ratio for the fuel and the temperatures involved – power matching. The net electrical output from the site remains the same after CO_2 capture retrofit. Some heat for the capture process is recovered from this plant; the rest is supplied from the existing plant. An example of this would be the use of a relatively small GTCC unit with a back pressure turbine on either a natural gas or a coal plant.

(e) Advanced coal boiler retrofit
Alternatively, power matching might be achieved using a new, larger coal boiler with a back pressure turbine to service several existing coal units retrofitted with capture; the use of a larger unit allows pulverised coal combustion and supercritical (or advanced sub-critical) steam conditions to be used. The output from the site remains approximately the same, although if the additional boiler is sized to be similar to existing units there may be some difference. In practice this is likely to be proposed only for coal plants. A large gas-fired boiler is clearly less efficient than a gas-fired GTCC unit, although gas boilers can also be more conveniently made smaller and so be dedicated to a single unit, easing operability issues.

(f) Gas turbine heat matched retrofit
All heat for the capture process is supplied from a natural gas CHP plant with the highest possible power to heat ratio for the fuel and the temperatures involved – heat matching. Excess power would be exported from the site with this configuration. This could be applied to retrofits of either gas or coal plants.

With appropriate integration it will be shown later that options (a) and (d)-(f) can all give good levels of efficiency. Options (b) and (c) do not produce as much power as possible from the additional fuel used, so overall plant efficiencies are lower and corresponding capture efficiency penalties are higher.

It is important to note, however, that factors other than efficiency, such as capital cost, may be important in determining overall retrofit project economic performance, particularly for demonstration purposes or where space is limited. Capital cost and also speed of response for start-up are also likely to be important for power plants with CCS, especially when operating at low load factors. A plant with an additional heat and power supply unit also does not necessarily have to operate it all the time; for example, it might be more valuable at periods of high demand, under more extreme climatic conditions or at part-load or transient operating conditions. Optimum operating approaches are also likely to alter as fuel and/or carbon prices change.

3.2 Integrated post-combustion capture[6] retrofits to existing PC and NGCC plants

Although only one of the options for retrofit, integrated solutions with steam extraction from the existing power plant steam turbine can deliver optimum thermodynamic performance without any additional heat and power source. Such steam extraction, at a lower level, is also essential for optimum thermodynamic performance in all other cases except where a fairly large additional CHP plant is used to provide all of the heat for PCC and hence also an excess of electricity. This section, which is based on Lucquiaud (2010a), therefore discusses aspects of implementing integrated post-combustion capture retrofits at existing PC and NGCC plants.

As outlined in the literature review in Section 2, existing power plants that were not designed to be retrofitted with CO_2 capture have tended to be disregarded as suitable candidates for CCS. Low plant efficiency with capture and hence poor economic performance compared to new-build projects are often cited as critical barriers to capture retrofit. There also appears to be some confusion in the literature regarding whether the energy requirement per tonne of CO_2 captured in a retrofit is higher for low efficiency power plants, or not. One response to these concerns might be to increase the efficiency of the base plant by rebuilding the boiler and turbine with more advanced steam conditions, e.g. Panesar et al (2009), but whether this modification can be justified on the grounds of efficiency increase alone will depend on the project -specific factors that determine the capital expenditure involved. Of course, if major boiler/turbine refurbishment is necessary anyway then this is likely to use modern designs that give an improved performance and also facilitate effective integration (e.g.as reported in the media[7] for the boiler/turbine refurbishment for the proposed SaskPower Boundary Dam project). Since costs and performance, and whether or not boiler/turbine refurbishment is required or is just an option, are site-specific matters that cannot be generalised for existing plant upgrade options, in this study the scope for justifying such expenditure is examined using a sensitivity analysis of the trade-off between improved efficiency and capital expenditure for new plant.

With CCR (carbon capture ready) plants the power cycle is designed to be able to accommodate a future retrofit with CO_2 capture, although it may have not been possible to incorporate the scope to

[6] It is implicitly assumed here that a combination of heat and electric power will be required to operate the capture plant, as currently with solvent absorption systems. The overall result of supplying heat and power is, however, expressed as a loss of overall electric power output (EOP – electricity output penalty) and both the methods presented and the Excel spreadsheet can accommodate any range of heat and power requirements for appropriate (e.g. but not the use of an external boiler when only electricity is required!) retrofit options.

[7] e.g. http://www.green-business.ca/Carbon-Trading/News/hitachi-partners-in-saskpower-boundary-dam-ccs-demo-project.html Last accessed 14 March 2011

readily accommodate all future capture equipment options. In this case, and at other non-CCR plants, it is necessary to consider alternative approaches to retrofitting CO_2 capture. The proposed methods for steam supply and heat recovery for integrating retrofitted capture systems with the power plant steam cycle, which are possible with CCR plants, may, in some cases, incur excessive energy penalties if it is assumed that they are also the best option for non-CCR plants. Alternative approaches can, however, achieve effective thermodynamic integration between the capture and compression plant and the power cycle of a retrofitted unit. This can allow efficiency penalties close to those seen when CO_2 capture is used at new-build or retrofitted to CCR plants to be obtained for a wide range of steam cycles (although other restrictions, such as space limitations, may still apply).

This sub-section explores themes related to how capture energy penalties are quantified and both general principles and practical options to reduce integration losses at non-CCR plants.

3.2.1 Electricity output penalty for integrated PCC retrofits

The overall energy requirement for CO_2 capture is commonly indicated in two ways. Some studies report it as a fractional fall in the total electricity output from the plant (e.g. a 20% drop in output from the plant). Others consider a percentage point drop in the overall thermal efficiency of the plant (e.g. a 9 percentage point efficiency penalty), which is a fall in electricity output per unit of fuel energy input. The latter option is the more representative metric since the overall energy requirement is virtually independent of the base plant efficiency, as shown in Appendix 1. Thus, although the fraction of the total plant output lost for CO_2 capture and compression in low efficiency plants is greater than in high efficiency plants, the absolute loss of output per tonne of CO_2 captured is the same.

The efficiency penalty is, however, affected by fuel composition. The amount of CO_2 generated by combustion per unit of useful thermal energy, and hence the total energy requirement for capture and compression, varies depending on the ratio of carbon content to heating value (see Appendix 2). An alternative metric is the electricity output penalty (EOP) per unit of CO_2 captured and compressed on a mass basis. It is composed of the sum of the loss of generator power output incurred by steam extraction and the power requirement for compression and ancillary equipment, divided by the absolute mass flow of compressed CO_2 exiting the plant boundaries, as shown in equation 3.1. Using EOP as a metric allows the performance to be assessed more independently of the fuel composition by concentrating on the intrinsic performance of the PCC systems for comparison. Changes in flue gas CO_2 concentration due to fuel composition will still affect energy requirements, but such changes are expected to be minimal between different plants burning the same fuel with similar excess air levels.

$$\text{EOP} = 10^6/3600 * (\text{Loss of generator output} + \text{Compression \& ancillary power}) \,/\, CO_2 \text{ mass flow} \qquad (3.1)$$

Electricity output penalty (EOP)	(kWh_e/tCO_2)
Loss of generator output	(MW)
Compression & ancillary power	(MW)
CO_2 mass flow	(kg/s)

The electricity output penalty relates to the efficiency drop of the power plant as follows:

$$\text{Efficiency penalty} = \text{Fuel specific emissions} * \text{Electricity Output Penalty} \qquad (3.2)$$

Efficiency penalty	(MWh_e/MW_{th})
Fuel specific emissions	($kgCO_2/MWh_{th}$)
Electricity Output Penalty	(kWh_e/tCO_2)

3.2.2 Updated rules for effective thermodynamic post-combustion capture integration

Six rules for effective thermodynamic integration of the PCC and compression system with the power cycle are established in Lucquiaud (2010a). They are based on initial suggestions by Gibbins et al (2004a), but have been updated drawing on results in more recent literature (see italics).

1. *For new build projects*, add heat to the steam cycle at as high a temperature as possible (i.e. be prepared to use best available steam conditions if commercially justified). *For retrofits to existing plants, though, the penalty per tonne of CO_2 emissions avoided is independent of the (turbine inlet) steam conditions.*
2. Reject heat from the steam cycle, in the steam extracted for solvent regeneration, at a temperature *as close as possible to the temperature of regeneration of the solvent. Optimise solvent temperature of regeneration to minimise the sum of the overall electricity output of the capture system and the CO_2 compression system.*
3. Produce as much electricity as reasonably possible *from the power cycle (i.e. be prepared to use additional turbines for retrofit projects if commercially justified)* and from any additional fuel used, consistent with rejecting heat at the required temperature for solvent regeneration.
4. Make use of waste heat from CO_2 capture and compression in the steam cycle.
5. *Anticipate* the use of the latest solvent developments *throughout the whole operating life of the plant.*
6. Exploit the inherent flexibility of post-combustion capture *(e.g. to shift the financial penalty of capture from high to low operating profit periods of time and/or to accelerate ramp rate during transient operation, if necessary).*

For state-of-the-art solvent and state-of-the-art thermodynamic integration at the time of writing the electricity output penalty of fully integrated PCC is of the order of 250-300 kWh/tCO_2 for pulverised coal plants (see Table 3.1), and of the order of 350-450kWh/tCO_2 (depending on solvent used – see Appendix 7) for natural gas combined cycle plants.

Table 3.1 Characteristics of PCC plants with thermodynamic integration in previous studies, leading to Electricity Output Penalties (EOPs) per tonne of CO_2 captured

	Owens et al (2000)	Owens et al (2000)	Bozutto et al (2001)	Parsons et al (2002)	IEAGHG (2004, Fluor)	IEAGHG (2004, MHI)	Ramezan et al (2007)[8]	Xu et al (2007)	Xu et al (2007)	Panesar et al (2009)
Steam conditions	Supercritical	Ultra-supercritical	Subcritical	Subcritical	Ultra-Supercritical	Ultra-Supercritical	Subcritical	Supercritical	Supercritical	Ultra-Supercritical
New-build or retrofit?	New-build	New-build	Retrofit	New-build	New-build	New-build	Retrofit	New- Build	Retrofit	Retrofit[9]
Solvent	MEA	MEA	MEA	MEA	MEA	KS1	MEA	KS1	KS1	
Thermal heat of regeneration (GJ_{th}/tCO_2)	3.8[10]	3.8	5.4[10]	4[10]	3.24	2.8[10]	3.6	2.6[10]	2.6[10]	
Steam cycle EOP (kWh/tCO_2)	345.8	345.8	348.4	227.3	174.7	150.5	213.5	171.5	161.6	
Steam extraction pressure (bara)	5.2	5.2	4.5	2.4	3.6	3.6	4.5	4	4	
Reboiler condensate return to condenser	YES	YES	YES	YES	NO	NO	NO	NO	NO	NO
Heat recovery into power cycle	NO	NO	NO	NO	YES	YES	YES	YES	YES	YES
Ancillary power EOP (kWh/tCO_2)	66.5	69.2	122.1	134.8	146.0	136.0	155.3	141.1	143.5	
CO_2 delivery pressure (bar)	83	83	139	103	110	110	139	140	140	
Overall EOP (kWh/tCO_2)	412.3	415.0	470.6	362.1	320.7	286.5	368.9	312.6	305	319.5

[8] Note that Bozutto et al (2001) and Ramezan et al (2007) apply to the same plant at Conesville Unit 5, Ohio, USA. Ramezan et al (2007) is discussed further in Appendix 3.
[9] Advanced boiler turbine retrofit and CO_2 capture retrofit
[10] Estimated

3.2.3 Steam turbine options for integrated PCC retrofits to existing PC plants

Steam turbine and power cycle options for the integration of PCC systems with new-build plants operated at base load have been studied extensively, both in industry and academia. These studies typically aim to reduce the electricity output penalty of CO_2 capture by thermodynamic integration independent of the specific solvent regeneration energy requirements.

One important aspect for thermodynamic integration is the quality of steam extracted from the base power plant steam cycle – or the value of its equivalent mechanical work – to provide condensing steam for solvent regeneration. Turbine designs typically proposed for new-build plants set the pressure at the extraction point to match the temperature of regeneration of the solvent chosen for PCC. In practice, this normally implies that the pressure in the crossover pipe between the intermediate pressure (IP) and the low pressure (LP) turbine – the IP/LP crossover pressure – is directly set by the way the solvent reboiler is operated and, hence, by extension by the thermal stability of the PCC solvent.

The approach proposed for new-build plants is, however, likely to be impractical for most of the existing fleet of coal-fired plants. The IP/LP crossover pressure is usually a degree of freedom for turbine developers when CO_2 capture is not considered, and is determined by other drivers such as capital cost. Consequently, the existing fleet has a wide range of IP/LP crossover pressures. It is, therefore, necessary to carefully consider the particular steam cycle at any given site for effective thermodynamic integration with capture and also good operability after retrofit to be achieved.

A detailed technical analysis of turbine retrofit options is provided in Appendix 3. If space is available near the turbine island, this analysis suggests[11] that retrofitting the power cycle of an existing plant with two let-down back-pressure turbines will lead to any existing turbine configuration achieving performance that is close to a new-build power cycle with capture from the outset, irrespective of the initial steam cycle design. The two let-down back-pressure turbines are used, respectively, to expand the steam extracted from the IP/LP crossover pipe in the steam cycle to the PCC solvent reboiler and to expand the steam that remains in the steam cycle as it passes from the IP turbine outlet to the LP turbine, where throttling losses would normally occur.

If space is constrained, other options are likely to be more appropriate. For steam cycles starting with a moderately elevated IP/LP crossover pressure without capture (typically 7-8 bar and above), the addition of a smaller single let-down turbine in the extraction line is likely to be worthwhile. When this addition is combined with the reblading of the very last stages of the IP turbine with higher-strength blades that will allow operation at lower IP/LP crossover pressures, it is possible to achieve close matching to the performance of a new-build unit with CCS, by eliminating the need to throttle at the LP turbine inlet. In this case, the IP turbine outlet pressure floats down to a lower value when steam is extracted for capture. Good operability can be obtained in this approach since the full original steam

[11] But this is still a preliminary theoretical study: more detailed engineering work is required by turbine vendors to establish the technical and economic characteristics of such an arrangement and also to address operability issues such as running at part load.

swallowing capacity of the LP turbine is maintained. This can allow a return to maximum power output when needed, as well as providing options for subsequent modifications to take advantage of solvent improvements.

If the initial IP/LP crossover pressure was below the desired reboiler steam pressure then it would probably be possible to extract steam efficiently via a pass-out back-pressure turbine from the reheater outlet as described in Appendix 4, section (b) for combined cycle steam turbines. This is not expected to be required in most cases, however, for pulverised coal plants.

An important conclusion of this analysis is that the choice of existing power plants that could be suitable for CO_2 capture retrofit is wider than has sometimes been considered to be the case in previous work (e.g. see Section 2). This is a result of the lost electricity output per unit of CO_2 captured being independent of the steam cycle peak pressure and temperature (see Appendix 1), and also potentially being effectively independent of the existing steam cycle design as a result of appropriate choice of turbine retrofit. This means that other, site specific, factors such as the size and age of the existing power plant may be more important in determining retrofit potential.

3.2.4 Options for integrated PCC retrofits to existing natural gas GTCC plants: steam extraction and flue gas recycling

Two options are most likely to be considered for retrofitting GTCC plants that continue to use natural gas as their primary fuel, but with CCS:

a) Post-combustion capture from flue gas, or

b) Replacing the gas turbines to burn hydrogen produced with a pre-combustion capture system.

At the time of writing, and for the near to mid-term future, lower costs of electricity are expected for gas plants with post-combustion capture (IEAGHG, 2005) that are designed to be able to operate at high load factors with CCS.

If, however, lower average load factors are required from the CCGT with CCS, as might be required for operation in conjunction with large amounts of wind generation capacity, then remote production of hydrogen using pre-combustion capture from units sized to meet the average hydrogen consumption rate and with buffer hydrogen storage (in pipelines and possibly purpose-built salt storage caverns) could be less costly, particularly if coal prices are low relative to natural gas. Further examination of this relatively large scale integrated system approach is beyond the scope of this study, but an analysis is presented by Davison (2009).

With natural gas plants the option of providing heat for solvent regeneration using a separate ancillary boiler can, at first, seem a more attractive option than for coal plants, since it does not involve a change/ partial switch of fuel. However, foregoing the efficiency benefits that can be achieved by thermodynamic integration between the capture process and the power cycle can make the stand-alone boiler option significantly less attractive. Even if a back pressure turbine is added and generates as much power as possible from the steam (as opposed to the lower-power option of just meeting capture plant power loads) this still does not satisfy the criterion of generating as much power as possible from the additional fuel used. This criterion is, however, met if the additional fuel is used in a gas turbine with a heat recovery steam generator (HRSG) and back-pressure turbine. As outlined in section 3.1, the GT system might typically be sized to meet the heat demand for CO_2 capture and provide additional power for export or to meet the power demand of the CO_2 capture unit and provide some of the heat required (with the remainder coming from the existing steam cycle). A GT-based additional heat and power system could be applied to either gas or coal plant retrofits.

Steam turbine retrofit options for NGCC plants where steam for solvent regeneration can be extracted from the reheater outlet offer the possibility of retrofitting a wide range of solvents without compromising performance. This provides a range of options to accommodate uncertain future technology developments, notably if the outcomes of policy developments facilitate CCS retrofit on coal plant first and significant technology development takes place before retrofit to natural gas-fired power plants. Additionally, these retrofit options can accommodate steam turbine configurations with a combined IP/LP cylinder where the IP/LP crossover is not easily accessible. In an example case (see Appendix 4) the electricity output penalty is of the order of 405 kWh/tCO_2 with steam extraction compared to 890 kWh/tCO_2 if the heat is provided by a separate ancillary boiler and to 820 kWh/tCO_2 with a back-pressure turbine providing power for compression and ancillary equipment.

Flue gas recycling (as discussed in Appendix 5), also known as a semi-closed gas turbine cycle (SCGT), leads to a reduction in the consumption of air and hence the concentration of N_2 and O_2 in the exhaust stream, accompanied by a corresponding rise in the CO_2 content. In addition, any removal of water from the recycle stream will increase the flue gas CO_2 concentration. Since SCGT cycles consume less air, there is also less N_2 diluting the CO_2 passing out of the plant. As a result the total mass flow rate of gas passing out of the plant, and hence through any PCC unit, is reduced. Most authors consider this latter effect, rather than the increase in CO_2 partial pressure, to be the most important benefit of semi-closing for PCC as it can lead to a significant reduction in the size of the absorber column.

Due to the higher CO_2 content, there is a rise in molar specific heat of the gas streams passing through the engine. This leads to a rise in engine specific work output for a given combination of turbine inlet temperature (TIT) and molar (and hence volumetric) flow rate. The higher CO_2 content affects the performance of the gas turbine's turbomachinery. Most authors argue, however, that this effect is small. In particular, the shape of compressor and turbine maps is relatively insensitive to modest changes in gas thermodynamic properties (Cumpsty, 2010). If the existing turbomachinery of the core gas turbine can be retained with some modification this would be a clear benefit for retrofitting; otherwise a more comprehensive refurbishment of the plant would be required, possibly after the original conventional GT operating life has been used up (i.e. after perhaps around 20 years of service).

Because of the higher specific heat of the compressor exit gas and the reduced oxygen concentration of that gas, a fall in combustion temperature for a given fuel/'air' equivalence ratio takes place. This leads to a corresponding fall in thermal NOx generation within the combustion chamber. It is likely that new, redesigned combustion chambers would be required, unless the degree of recirculation is small. Elkady et al. (2008) stated, however, that exhaust gas recirculation levels of up to 35% are feasible without major modifications of existing combustion technology. Nonetheless, if a major change to the combustion chambers is required this may be feasible on large frame gas turbines with annular combustion cans that are designed to be changeable. Additional benefits of semi-closing gas turbine cycles may also be a reduction in carbon monoxide emissions and the ability to use ‘water harvesting’ from the recycled flue gas to provide water for the power plant itself or for other uses.

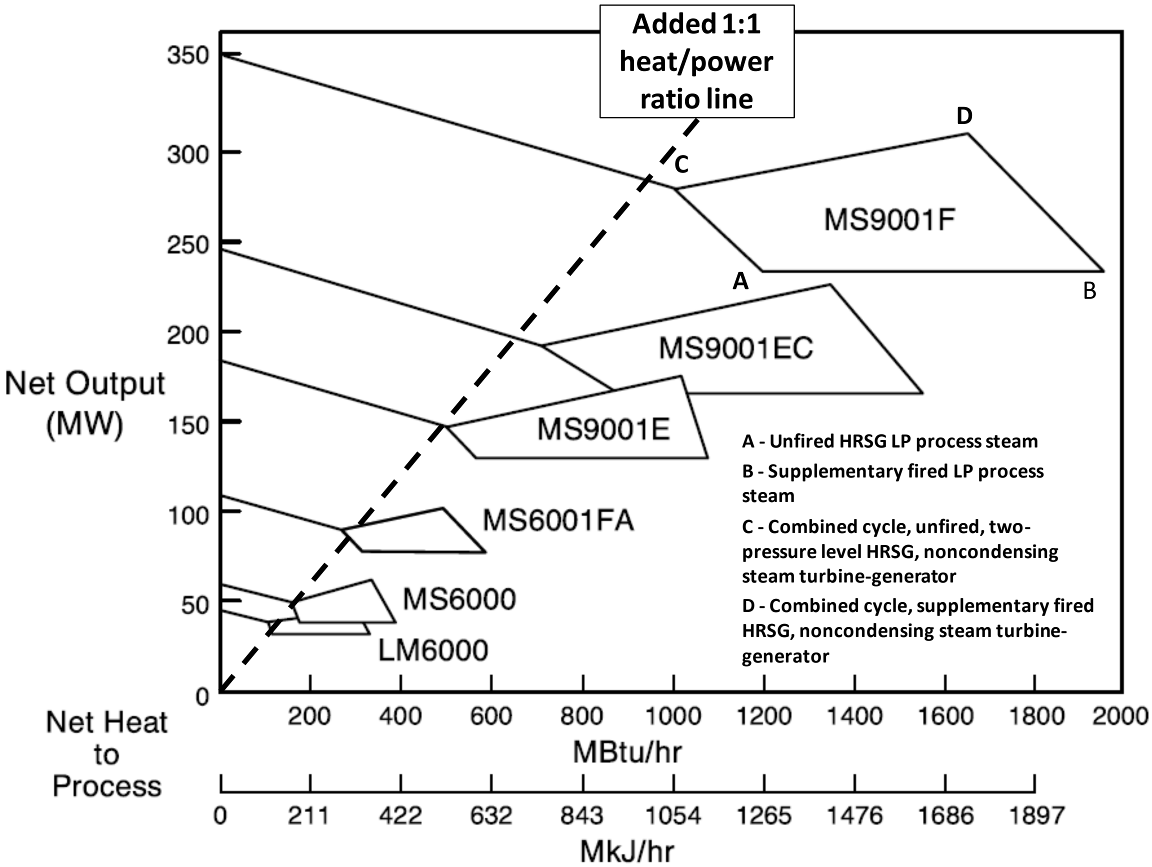
3.3 Technical options for capture retrofits using additional CHP plant

CHP plants supplying additional power and heat have been characterised in the overall plant technoeconomic performance analyses in this study using the following simple overall performance parameters (values specified in Section 5.3 ‘Performance parameters for additional plant that may optionally be used to supply heat and/or power for capture retrofits’):

- Additional plant fuel specific emissions
- Additional plant energy utilisation factor
- Additional plant power/heat ratio (See Figure 3.1)
- Capture level for post-combustion capture plant applied to the CHP plant
- Additional compression and auxiliary power per tonne CO_2 captured
- Additional plant CO_2 heat requirements per tonne CO_2 captured

In addition for CHP cases a value for the base power plant efficiency boost from heat recovery from the capture plant can be specified. This is the benefit achieved from substituting steam extraction for condensate/feed water heating in the main steam cycle by heat recovered from the capture and compression process. This value is subsumed in reported efficiency penalty figures for fully-integrated post-combustion capture for coal plants[12] but might be a factor in retrofits where less steam was being extracted from the main steam cycle and hence a greater fraction of heat recovery due to feed water heating could be assigned to the additional CHP cycle. Based on previous work (Gibbins and Crane, 2004c) a value of around 0.5 -1 percentage point boost might be expected if all the condensate heating was replaced by recovered heat. More exact numbers would require engineering analysis for a specific project, since it depends on the details of the condensate/feed water heating system used. In general, this type of integration would be optional, with the conventional heaters and extraction points being maintained in use with minimal flows so as to be fully available when required.

[12] Condensate heating is unlikely to be available for CCGT plants since the heat available will be below the temperature of the LP temperature pinch in the HRSG, a region where excess heat for condensate heating is available anyway.



R.W. Fisk & R.L. VanHousen, Cogeneration Application Considerations, GE Power Systems, GER-3430F

Figure 3.1 Illustrative heat/power ratios for gas turbine CHP plants
(Note this is from a 1996 paper and may not represent current commercial products from this supplier)

3.4 Oxyfuel retrofits to existing PC plants

The majority of this section has focussed on integrated PCC retrofits. This sub-section outlines some technical considerations for oxyfuel retrofits to PC plants. At the time of writing, there appears to be a broader range of existing literature available in this area and this literature is the basis for much of the discussion here. This includes some contributions from relevant original equipment manufacturers, as well as work undertaken in the academic community.

Wendt (2009) provided a summary of issues, opportunities and challenges for retrofitting oxyfuel at existing plants. He noted that flue gas recycling can be controlled so that the system “looks like” an air-fired boiler with existing boiler heat transfer surfaces and steam cycle requiring minimal changes. Wall et al (2009) reported results of a study that considered heat transfer in oxyfuel boilers using CFD (computational fluid dynamics) modelling. They concluded that an oxyfuel flame could be longer than an air-fired flame, leading to a potential need to change burner dimensions and/or the extent of swirling flow for similar flame and furnace distributions to be obtained. Further work in this area is presented in Khare et al (2008).

Wendt (2009) identified four key concerns for oxyfuel technology that can be relevant in considering whether it is likely to be used as a retrofit option at existing plants:

- Energy supply for oxygen separation, currently in a cryogenic air separation unit (ASU) – oxygen purity levels may be adjusted to optimise overall plant performance;

- CO_2 purity requirements, including considering which technologies are needed for CO_2 purification where it is required;

- Ingress of air to the boiler (also known as air in-leakage), which dilutes the CO_2 stream exiting the boiler; and

- Cannot be used for partial CCS (unlike post-combustion capture where the volume of CO_2 that passes to a CO_2 capture unit can be varied).

Where it cannot be avoided, the reduction in the concentration of CO_2 in the flue gas associated with air in-leakage requires additional energy for CO_2 clean-up. For example, Farzan et al (2008) reported work undertaken by Babcock and Wilcox, Air Liquide and Battelle to develop oxy-combustion technology to retrofit to coal-fired boilers. For their 'low air infiltration' case power for CO_2 compression was reduced by around 15-18% from 150-160 kWh/tonCO_2 stored to 125-135 kWh/ton CO_2 stored.

Tigges et al (2009) presented work undertaken by Hitachi which suggested that an oxyfuel boiler will be operated at slightly below ambient pressure for safety reasons, as happens with conventional air-fired boilers, which may lead to some air in-leakage. They also reported, however, that overall in-leakage could be reduced to around 1% of the gas flow to the boiler by implementing a series of measures outside the boiler house. These measures included switching the mill purge gas to CO_2, replacing the atomising gas in the de-NOx plant with CO_2 and replacing the electrostatic precipitator (ESP) used for ash removal with a gas tight system. It is not clear, however, to what extent this low figure could be reached for existing boilers which were not designed with gas-tightness as a high priority.

As noted by Wendt (2009), another important consideration in determining the technical performance of power plants retrofitted with oxyfuel capture is the energy requirement for the air separation unit (ASU). Panesar et al (2009) reported work carried out by a consortium including Mitsui Babcock (now Doosan Babcock) and Air Products. They suggested that a relatively low purity cycle that produces around 95% purity oxygen (compared to 99.5% for a high purity cycle) could be the technology of choice, at least for first generation oxyfuel power plants. This would reduce both capital cost and power consumption associated with oxygen supply, although at the cost of a slight increase in energy required for removing inert gases from CO_2 produced by oxyfuel combustion. They also concluded that "efficient heat integration between the cryogenic ASU (e.g. recovery of low grade heat from ASU compressors) and the power plant will be a necessity".

Additionally, Panesar et al (2009) suggested that full air-firing capability can be maintained at power plants retrofitted with oxyfuel capture. This is discussed further by Sekkapan et al (2007). Tigges et al (2009) stated that "oxyfuel is an attractive option because it does not have major impact on the boiler-turbine steam cycle". They also considered a design where the boiler could be operated in an oxygen or air-firing mode after CO_2 capture retrofit and presented CFD (computational fluid dynamics) results showing an oxyfuel flame where oxygen concentration was set to match the temperature distribution of an air-fired flame.

Some other contributors to the literature have, however, suggested that significant differences would have to be expected when oxyfuel boilers and air-fired boilers are compared. For example, Doukelis et al (2009) explored the potential to combine partial oxyfuel combustion with post-combustion capture as a retrofit application. This combination of CO_2 capture options was considered to be of interest so that some of the more significant alterations to the boiler island that could be required for an oxyfuel retrofit were avoided, but with the post-combustion component added so that high capture rates can be achieved. They also concluded that effective heat integration to reduce the energy penalty associated with CO_2 capture retrofit was likely to be important for optimum economic performance.

Additionally, it is important to establish the requirements for cleaning and compressing flue gas produced by oxyfuel combustion (at both new and retrofitted sites) for more traditional approaches to CO_2 capture using oxyfuel. Panesar et al (2009) reported that all of the SOx and most of the NOx (oxides of sulphur and nitrogen) present in oxyfuel flue gas will be converted to sulphuric and nitric acid as part of the CO_2 purification and compression process. It is expected that these streams can be neutralised (if no market exists for their use) and treated by existing waste water treatment facilities associated with flue gas desulphurisation (in jurisdictions where flue gas desulphurisation is required for air-fired PC power plants) with little or no plant upgrade required.

Oxyfuel capture also has the attraction of being a closed, solvent-free system, with no possibility of adding volatile solvent or degradation products to a large vented flue gas stream, as in post-combustion systems. The lifecycle environmental impacts that arise from production and disposal of post-combustion solvents are thus avoided.

4 Economic aspects of CO_2 capture retrofit to existing plants

This section will discuss some of the underlying principles involved in determining economic parameters for characterising different capture options at power plants.

4.1 Background to the economic analysis

4.1.1 Options available to the operator of an existing fossil power plant facing pressure on its carbon dioxide emissions, the restriction to retrofit or new build CCS in this study and the use of LCOE in decision making

Options that are in principle available to the operator of an existing fossil power plant facing pressure on its carbon dioxide emissions (and/or a financial inducement to produce electricity with CCS) may include:

(1) Subject to being compliant with any emissions performance standard, pay any penalty for carbon emissions while running the plant at similar load levels to previously.

(2) Subject to being compliant with any emissions performance standard, reduce plant load but restrict operation to high value periods. Pay any penalty for carbon emissions. Make up demand with new capacity elsewhere if necessary.

(3) Convert the plant to operate wholly or partially on a fuel which will be attributed with lower carbon emissions (i.e. natural gas if existing plant is coal fired, or biomass for both coal and natural gas). Pay any penalty for carbon emissions.

(4) Retrofit the existing plant with CCS. A number of retrofit options are described in Section 3.

(5) Close the plant down and build a new plant without CCS but with a fuel which will be attributed with lower carbon emissions (i.e. natural gas if existing plant is coal, or biomass for both). Pay any penalty for carbon emissions.

(6) Close the plant down and build a new plant with CCS.

Options 1 to 4 potentially extract some further value from the existing plant. Options 5 and 6 do not.

Option 1 does not reduce CO_2 emissions at the plant. Option 2 may reduce CO_2 emissions somewhat, but the overall effect depends on the new capacity that replaces the reduced on-site electricity output. Similarly options 3 and 5 will reduce emissions to a variable extent. Whether or not options 1, 2, 3 and 5 are available and/or economically desirable depends on specific market conditions facing the plant owner and a general assessment of their merits with respect to CCS options 4 and 6 is not possible.

It is likely, however, that quite high carbon prices would be required to make options 1 and 2 unattractive to utilities if they were allowed, including because there is minimal financial risk involved to the utility since carbon costs can often be passed through to customers more easily than the capital costs involved in delivering options 3-6. In this case the interests of the electricity supplier in reducing commercial risk may be at variance with the interests of the electricity customers in minimising overall electricity costs.

For carbon emission costs, there is a general expectation that these will rise over time. If such a rise could be relied on then the decision to retrofit might take place at a carbon value somewhat below the average value required to cover the long run marginal costs (i.e. including capital costs) of the retrofit. In the early years of the project the benefits of running CCS would outweigh increases in some components of the short run operating costs (and/or reductions in electricity sales revenues) but only make a partial contribution to paying off the capital costs; the latter would have to be recovered fully in later years when carbon emission penalties (or subsidies) were higher. Such an early retrofit might also give greater confidence in an adequate remaining life for the existing plant to justify the investment in retrofit, as well as obviously reducing cumulative CO_2 emissions from the plant.

The time value of money, even with future carbon value certainty, obviously limits the period when such a failure to cover full project costs can be tolerated. But in reality the asymmetric exposure to future carbon value fluctuations between retrofit and 'just pay for emissions' is likely to have a greater role in delaying apparently-beneficial decisions to retrofit CCS (or take other investment-related decisions) while paying for carbon emissions until a much higher value for carbon actually exists than would occur if risks were neutral between the two options.

The tolerance of an investor to carbon value risk will also depend on the larger portfolio of assets which that investor has that are also subject to carbon value. If these exhibit inverse risks (e.g. unabated fossil power plants) to a retrofit or other CCS investment then the CCS investment can be expected to reduce the overall portfolio exposure.

In the context of the present study the expectation of changing carbon value and the asymmetry and subjective investor variability of risk makes a simple determination of 'the carbon price to trigger retrofit' impossible. For a start, at least one additional parameter must be quoted, to characterise future carbon price changes. The relative risk profiles of the non-investment and investment alternatives would also need to be estimated, probably by Monte Carlo methods.

The relative attractiveness of options 3 and 5, retrofit and new build with lower-carbon fuels, would obviously also be highly uncertain, depending as they do on the prices for the alternative fuels, as well as carbon price for unabated natural gas use and on the existence of any emissions performance standard. If existing coal plants had to comply with a 'natural gas standard' of emissions – e.g. 500 $kgCO_2/MWh$ or less – then either co-combustion of biomass (option 3) or replacement with natural gas plants (option 5) might be particularly attractive. If all fossil fuel use has to reach emissions levels that can only be achieved with CCS then obviously only dedicated biomass operation would be possible under 3 and 5, and even then there is a strong case to implement CCS on such biomass plants because of the high local emissions of CO_2.

If fossil fuel use with low levels of emissions is required then only options 4 and 6 are available. They will both achieve comparable results if CCS is applied to the whole of the fossil fuel use. If some component of the fossil fuel use in a retrofit, option 4, (e.g. a separate boiler providing heat for solvent regeneration) does not have to apply CCS then it may save costs, but this case cannot readily be compared directly with a new plant, option 6, which treats all of the CO_2-bearing streams.

4.1.2 The use of levelised cost of electricity (LCOE) in comparing options

One basis for the comparison between options 4 and 6, retrofit and new build with CCS, is the levelised cost of electricity (LCOE) for the two options, with no capital cost applied to the use of the retrofitted plant beyond necessary refurbishment costs. Even if the existing plant has not paid off its original capital investment, if the only other choice that is being considered is to replace it then this has no significance and the capital cost for the use of the existing plant assets (beyond any re-use or resale value, which are typically assumed to be of a similar order of magnitude to decommissioning costs) can be taken as zero. Any additional equipment (e.g. flue gas desulphurisation - FGD) will be assumed to be applied to the capture retrofit costs. Significant rebuilds of the existing plant at the time of retrofit with an introduction of supercritical steam conditions have been proposed in the past (Panesar et al, 2009; Lucquiaud and Gibbins, 2009a) but no such projects have been undertaken to date and costs are uncertain; if required they can be treated as a special case of new build on the same site with some capital cost savings.

The LCOE can be viewed as informing new build vs retrofit decisions as follows:

(a) A (probably regulated) utility is obliged to generate electricity as cheaply as possible under the carbon constraints, from either retrofitting an existing plant or building a new one (possibly on the same site). Depending on their other options for constructing new plant they may also need to maintain the same power output from the site (so not all of the retrofit configurations may be applicable).

(b) A (probably unregulated) utility has to decide whether it can get a better return on investment by retrofitting an existing plant or by building a new plant with CCS.

In the case of the former decision it is probably reasonable to assume that the retrofitted plant and the alternative new plant would have similar load factors in the future, since they are likely to be performing essentially the same function.

For the latter decision it is possible that a new build plant will have a higher load factor because it has a lower short run marginal cost (SRMC) for generation and so can run at lower electricity prices. In this case while both plants are operating they can be assumed to receive the same (unknown) electricity price, from which costs must be subtracted to get the net revenue. For periods when the retrofitted plant is constrained off the grid because electricity prices fall below its SRMC the maximum electricity price that the new build plant can be receiving is, however, partially known – it cannot be higher than the SRMC of the (less efficient) retrofitted plant. This significantly bounds the maximum additional revenue, compared to a retrofitted plant, which a new build plant can obtain by an increased load factor. It is, therefore, not correct to compare LCOE values calculated using load factors that differ between the various options since this implicitly assumes that electricity prices for the higher-load-factor plants would be higher than they in fact could be when other plants are assumed to be constrained off by low electricity prices.

In the economic analysis of the retrofit and new build CCS options in the spreadsheet introduced in the next section, the maximum revenue that can be obtained from this period (i.e. the SRMC difference multiplied by the specified difference in running hours) is applied to reducing the LCOE for the new plant over the period when both plants are operating (i.e. the, possibly shorter, running hours for the retrofit).

In practice, even in a situation in which the running hours for the retrofit plant are reduced, there is still a good chance that a retrofit to an existing plant will be more economically attractive than a more expensive new build replacement. During additional running hours for the new plant (when compared to the running hours for the retrofitted plant), by definition, even if the new plant is running it can pay off only a small part of its capital and so possibly not enough to reduce the remaining amount to the capital levels of the retrofit. The retrofit, as a cheaper, although less efficient, plant, then does better over the limited period when electricity prices might be high enough to cover the full capital costs that are included in the LCOE.

Similarly the economic lifetime for the new plant is likely to be longer than for the retrofit (e.g. 25 years vs. 15 years), but it is not clear what revenue will be obtained over these later years and certainly not possible to equate it with the common revenue stream that both plants will have equal access to over the period when the retrofit is operating. To allow for this it has been assumed that the new plant will have some residual economic value at the end of the lifetime of the retrofit plant, but the retrofit a negligible value (effectively scrap and site values are assumed to balance decommissioning costs).

That there is some difficulty in estimating the residual value of a new capture plant reflects a real uncertainty, especially while capture technologies are being developed. It is quite possible that technical progress will make early CCS plants obsolete well before the end of their economic, let alone their service, lives. It is also possible that electricity market conditions will change, with the potential for significant changes increasing with time. The options that building a short-lived retrofit confers, such as being able to buy a new plant after perhaps 15 years, or to choose a non-fossil alternative, clearly have some value. In practice, at interest rates of say 10%, the time value of money makes the level of the residual value relatively unimportant in LCOE calculations.

In order to give representative LCOE values for comparison the residual value of the new plant needs to be assigned to reducing the LCOE for the new plant that would be required in order to cover its costs over the hours and years for which both plants are running (i.e. the average electricity price that would be required during periods when both plants were operating to justify the new plant being built – neglecting risks and uncertainties). LCOE values for the new and retrofit options can thus be compared directly, with the lower value giving a better return. An illustrative return on investment (ROI) can also be calculated for the retrofit plant, assuming it receives electricity sales revenues equal to the LCOE of the new plant (which give an ROI equal to the specified interest rate for the new plant).

4.2 Factors determining LCOE values and LCOE adjustment methods

The underlying reason for implementing CCS is likely to be to achieve a reduction in CO_2 emissions as a benefit for society. There will be some cases where the CO_2 has intrinsic value (e.g. for enhanced oil recovery (EOR) or urea production) in which case the amount of CO_2 captured, rather than amount of CO_2 abated, will be more relevant. In these cases lower-efficiency plants will be at a relative advantage, a factor which will tend to favour existing over new build plants. But these applications will rely on project-specific circumstances and will not be discussed further.

In addition to the interest rate assumptions, which will be taken as the same for retrofit and new build options (i.e. similar levels of commercial risk are assumed) levelised electricity costs for the different CCS plant options will be a strong function of:

- the prices that have to be paid for fuel;
- equipment cost levels;
- the load factor that the CCS plant will achieve;
- assumed economic life; and
- the CO_2 capture level required.

Each of these factors is discussed in more detail below. CO_2 transport and storage costs may also be significant, but will depend on location. For a generic assessment of the relative costs for retrofit and new build it is necessary to assume that CO_2 transport and storage from the site of the existing plant is technically and economically feasible. Obviously this will not always be the case, although some preliminary studies (for the USA and the UK) that are reviewed in this report (see section 6) suggest that access to storage would be feasible for many sites. It is also necessary to assume that space and layout constraints for an existing plant do not prevent retrofit, and also would not prevent new build with CCS at the same location. This is also obviously a very site-specific factor, but again previous studies of fleet retrofit potential suggest that significant numbers of power plant sites would be able to accommodate retrofit (and so presumably new build) with CCS.

It is also implicit in a generic evaluation of their respective merits that the retrofit and new build plants will not receive significantly different benefits or disadvantages as a result of their location. This is most likely to be the case if the same site was to be used for both options. Such re-use of existing sites is likely to be widespread, to take advantage of features such as existing grid connections, water supplies and coal or gas delivery facilities. Local communities are also more likely to be accustomed to power plant developments on existing sites.

4.2.1 Fossil fuel prices

Fossil fuel prices in traded markets have seen large fluctuations in recent years, both in their absolute levels (e.g. see Figure 4.1 for four natural gas markets) and in the relative costs for coal and gas. As a general principle it is reasonable to expect that a widespread requirement for CCS from fossil fuels would be accompanied by downward pressure on fuel prices. The general justification for this would be utility fuel buyers negotiating with sellers along the lines of ‘I can only buy your fuel if I can afford to use it with CCS and sell into a competitive electricity market’. Under these circumstances it appears likely that significant reductions in fuel selling prices might occur since, in many cases, it appears that current price levels are well above long run marginal costs of production. Indeed, in some places fossil fuel production could be continued for an extended period, possibly until reserves in that particular location had been exhausted, at short run marginal production costs. There therefore appears to be scope for some CCS power plants to have access to low fuel prices in the future, if required to remain competitive with other low-carbon fuel sources.

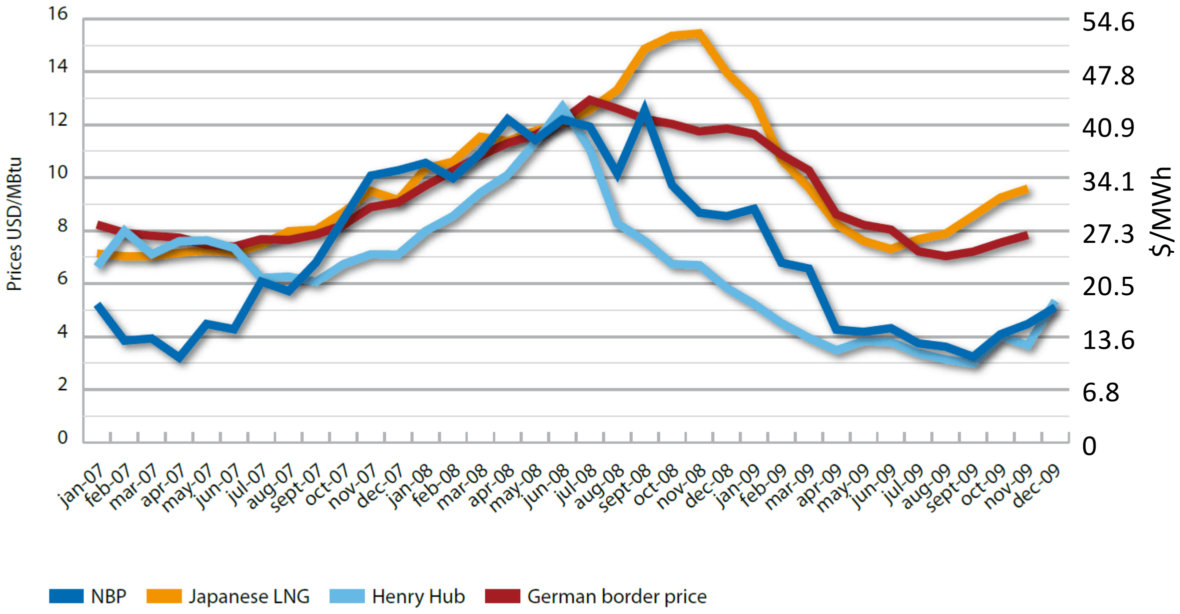


Figure 4.1 Monthly gas prices in key OECD regional gas markets (IEA, 2010)
NBP = National Balancing Point spot prices in the UK, Henry Hub is a US price; 1MBtu = 1.055 GJ

A downward pressure on fossil prices due to carbon emission restrictions will, however, only be observed if fuel sellers have no alternative markets. So if demand remains buoyant for coal and gas in countries, or even other plants in the same electricity market, that do not require CCS or do not have a high monetary penalty applied to CO_2 emissions, then fuel prices for CCS plants are also likely to be set at a higher level and one that might not enable CCS to be competitive. Fuel price levels for CCS would therefore appear to be dependent on the way national and global policies on CO_2 emissions from fossil fuel use are framed, as well as on 'normal' market forces.

Further, quantitative, analysis of possible future fossil fuel price levels is beyond the scope of this study, not least because of this strong policy dependence, but the above arguments are the basis for the inclusion of low fuel price levels in the sensitivity analysis. For a comparison of retrofit and replacement plants using the same fuels the results will obviously be less sensitive to absolute fuel prices.

In practice, however, power utilities in many places will also have the option of changing fuel when building a new power plant or of using a different fuel for some, or all, of the energy input to a retrofitted plant. Here similar considerations apply. Within the limits imposed by production costs, coal and gas selling prices will arguably adjust to levels at which they compete in the market – the issue is the nature of that market, including technical and other barriers to a shift to alternative electricity generation sources (e.g. intermittency for certain renewables, planning delay for new facilities etc.) . Again policy may have a strong effect on market conditions in a power sector. For example, is CCS on all fossil fuel use obligatory or is gas allowed to operate unabated while coal has to use CCS to achieve a similar specific emission level? And/or how many life-extended unabated plants are still operating, possibly under a carbon emissions trading regime that allows them to determine relative fuel+carbon price levels?

An analysis of ways in which relative coal and gas prices for future CCS plants might vary is also beyond the scope of this study, although it could be a very important factor in deciding retrofit options and retrofit vs. new build decisions, especially where the latter also involves fuel switching. All that can be said is that no firm conclusions on the economic merits of CCS options that depend on relative coal/gas fuel prices should be inferred from any results based on indicative fuel prices that are presented in this report. The spreadsheet model produced in this study could, however, be used to explore various fuel price combinations that might be of interest in a particular jurisdiction.

4.2.2 Plant construction costs

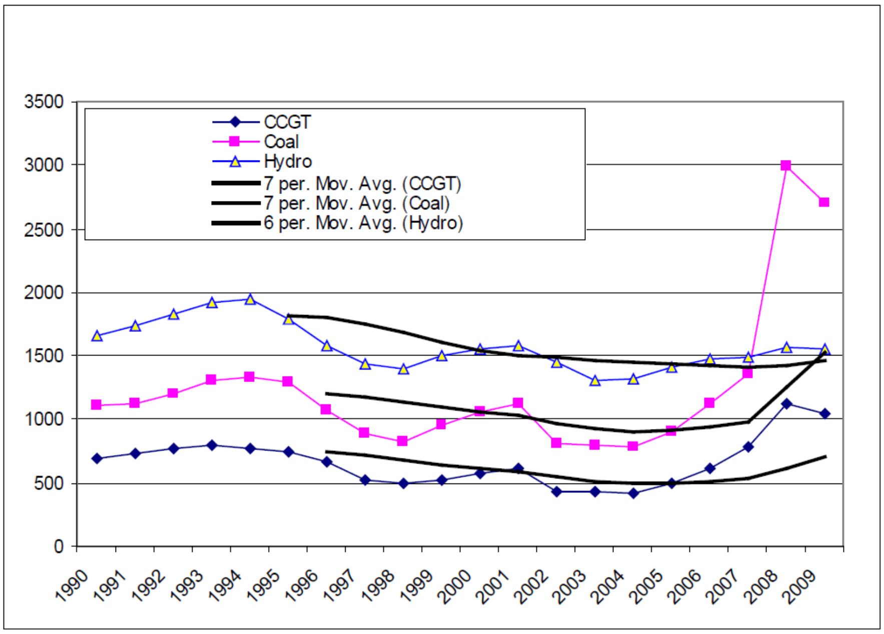
After a period of relative stability plant construction costs have varied significantly in the last few years and appear to be still changing – for example, see Figure 4.2. It is obvious that only very approximate values can therefore be assigned to capital costs in this study, even for new build plants without capture, for which actual historical costs are available. Costs are even more uncertain for capture equipment, for which no large-scale plants costs are yet available.

New plant capital costs of 2000$/kW and 1000$/kW net without capture have been used as nominal default values for new pulverised coal and natural gas combined cycle plants respectively. It is assumed these include all costs up to the point that operation commences (i.e. actual EPC overnight costs including any contingency expenditure items required, plus interest during construction, and owner's costs). Based on Figure 4.2 below these are approximate 2010 values, but in a strongly-fluctuating market great uncertainty exists. Since new build power plant and new build and retrofit capture plant capital cost levels are assumed to be correlated (see below) this is probably less serious when comparing relative new build and retrofit costs for the same fuel. Absolute capital and fuel costs, which can only be obtained reliably for a particular project at a particular time, would be more important for differentiating between plants with different fuels and also, obviously, for assessments of specific project costs.

In this study it is, however, proposed that capture equipment costs for new build and retrofit CCS plants built at the same time will be similar, possibly with an allowance (a 'retrofit factor') to allow for increased expenditure if the retrofitted plant was not designed to be capture ready. The ratio between capture equipment and power plant costs then becomes important in determining relative economic performance for retrofit and new build. A suitable metric for capture equipment cost is the CO_2 capture rate – $kgCO_2/hr$ - (for similar capture levels and flue gas compositions) while for unabated power plant costs are usually quoted per kW of generating capacity. As shown in Appendix 7, in previous studies the ratios (for capture plant $/($kgCO_2$/hr) to base plant $/kWe) range from approximately 0.2 to 0.4 for pulverised coal plants and from 1.2 to 1.8 (with a single, possibly unrepresentative higher value of 2.6) for natural gas combined cycle plants.

Capture equipment may of course not follow exactly the same market price trends as power plant equipment since it requires different materials and manufacturing facilities, but the ranges above are quite broad already. Relative rates of learning will also be different, with a higher likely rate of learning, but from a much more uncertain starting point for price reductions, for the capture equipment. Sensitivity analysis will be used in this study (see section 5) to explore these uncertainties.

Existing power plants may require capital expenditure at the time of retrofit for an FGD plant, if one is not fitted already, or for refurbishment of existing FGD units to attain adequate performance and operating life following the retrofit. Obviously these costs are predominantly site-specific. In the default cost comparison cases a constant $500/kW without capture has been added to allow for the necessary upgrading/life extension work on an existing coal plant and $250/kW for a natural gas plant. Possible costs this might have to meet are discussed below.



Source: Mott MacDonald

Figure 4.2 EPC[13] prices in constant 2009 $/kW from 1990 to present (Mott MacDonald, 2010)

FGD costs can reasonably be applied to a capture retrofit when the alternative is a new build that would automatically include FGD. There are some advantages in fitting FGD at the time of capture, since the specification can be chosen to match that of the capture equipment, reducing the likelihood that a secondary polishing process (probably as part of flue gas cooling) is required. FGD installation costs have also been variable and rose in line with other construction costs in 2008; current indicative costs for a new FGD are likely to be in the region of 200-400 $/kW capacity without capture (Sharp, 2009). Selective Catalytic Reduction (SCR) for NOx reduction may also have to be fitted, with indicative costs in the range 50-100 $/kW capacity without capture.

[13] Engineer, procure and construct; does not include owner's costs, interest during construction or contingency. These will vary, but are expected to be in the range of 10-30%.

Refurbishment costs for existing power plants are even more variable. Simbeck (2009) estimated approximately 200 \$/kW without capture for a boiler and turbine upgrade (which also included the costs of arranging for steam extraction). See also Section 6.2 for a more detailed description.

4.2.3 Load factor

The load factor (used here in the sense of annual capacity factor) of a CCS power plant will be at least as important as the equipment costs themselves in determining the capital element of the LCOE. In some markets the load factor for a CCS plant may be largely independent of the CCS plant's characteristics. For energy supply (but not necessarily grid services) they will always be less likely to run than most renewables and nuclear plants, but more likely to run than unabated fossil[14]. Whether or not there are likely to be significant differences between retrofitted and new-build CCS plants due to different SRMC values will depend on a number of factors including the size of the CCS generation fleet relative to the total demand and the nature of the variation in that demand over time.

In any case, as noted above, if it is assumed that a more efficient new build CCS plant is run as baseload and a less efficient retrofit CCS plant would be 'two-shifting'[15] or possibly even be running for shorter periods, then the former will typically be receiving gross revenues for its operation (electricity purchase prices and any other revenue sources) that in total are no higher than the SRMC for the less efficient plant.

In order to allow an explicit comparison of cases in which it is assumed that the new and retrofitted CCS plants have different load factors the following procedure is therefore adopted:

a) The LCOE is calculated for both the retrofit and the new build plant for the lower, retrofit load factor

b) The LCOE for the new build plant is then reduced by an amount equal to:

$$(\text{SRMCretrofit} - \text{SRMCnew}) \times \frac{\text{Length of time when both plants are operating}}{\text{Length of time when only new build plant is operating}}$$

This is the maximum reduction in equivalent LCOE for the new build plant, since it assumes that it receives the highest possible price for the electrical energy it produces when it alone is operating. This period then makes a relatively minor contribution to capital cost recovery; both plants would have to recover most of their capital costs during periods when higher electricity prices prevail and they are both operating.

[14] Whether the cost of a reduced load factor for CCS and other dispatchable plants is applied to them or to the intermittent renewables displacing them is also not addressed – in either case it is anyway likely that these costs will fall on the electricity consumer or taxpayer.

[15] i.e. Running for approximately 16 hrs/day to meet higher day time loads, but not run over night. Might also be classified as 'mid-merit', rather than baseload plant.

4.2.4 Assumed economic life and residual value

As outlined above, to allow a direct comparison of the LCOE values for new and retrofit plants when the latter is assumed to have a shorter life (see Figure 5.5.7 in the next section) the monetary value for the extra years of the new plant's life are represented by assigning a residual value to it at the end of the retrofit plant's life span, when the retrofit is assumed to have zero residual value (i.e. scrap and site value equals decommissioning costs). Uncertainty with respect to this residual value correctly reflects uncertainty as to the competitive position of a plant that is built now at some time into the future. The shorter life of the retrofit confers an advantage in that it is possible to invest in up-to-date plant when the retrofitted plant is shutdown, rather than needing to operate what will then be a relatively old plant for longer in order to be able to pay off its original investment.

To adjust the LCOE value for the new build plant to take into account its residual value this is converted into an additional annual, and then hourly, revenue stream for the new plant over the period for which both the existing plant and the new plant are operating (this is in addition to any load factor adjustment as described in the previous section). Since both plants can reasonably be assumed to have access to the same electricity prices over this period then LCOE values can be compared. The difference between LCOE values reflects the difference in the net revenue (after deducting other costs) that will be achieved.

Although electricity prices cannot be predicted, illustrative relative rates of return on investment (ROI) for retrofit options can be estimated if it assumed that the adjusted new build LCOE value is at least met, meaning that it is assumed that a new build CCS plant investment would just achieve its required hurdle rate (and so, at least potentially, be a counterfactual for a retrofit). In this case, if the LCOE for a retrofit is lower than the corresponding adjusted equivalent LCOE for the new build, then the retrofit will have a higher ROI.

4.2.5 CO_2 capture level

In this study only retrofit and new build options that seek to obtain high levels of CO_2 capture are analysed in detail, so only retrofit options that set out to attain a high (85% or higher) level of capture from all CO_2 sources and so achieve specific emissions below 150 kgCO_2/MWh for coal and 100kgCO_2/MWh for gas are compared with new build CCS plants. Lower emission values are achieved for many options, although the ultimate level will depend on the technical performance of the capture option and the drivers in place to reduce residual emissions to very low levels on particular plants instead of, possibly, applying CCS to a larger number of plants. At these selected ranges of emission levels the results from the economic parameter calculations are anyway relatively insensitive to variations in future carbon prices (unless they are assumed to reach very high levels).

'Partial capture' and in particular achieving 'gas level' emissions (e.g. 500 kgCO_2/MWh (1100 lbCO_2/MWh), as in the current Californian emissions performance standard[16]) has also been considered in some studies. However, while this might be economically competitive in markets with high natural gas prices and relatively low equipment prices (and also in

[16] http://www.newrules.org/environment/rules/climate-change/greenhouse-gas-emissions-performance-standard-power-plants-california

locations where CO_2 would have a value for EOR) it seems that, under current market conditions, such partial CCS on coal would be much less competitive than using unabated natural gas.

Partial capture is likely to be applied as an interim stage in early CCS demonstration projects, particularly for post-combustion capture, but in the longer run CCS plants that achieve high capture levels are likely to be required to meet projected CO_2 emissions targets and arguably have analogous reasons to receive support as other novel non-fossil low carbon generation sources. Economies of scale, including with respect to pipeline transport, also favour capturing as much CO_2 at a given site as is reasonably possible.

5 Examination of the relative economics of capture retrofit and new build CCS options for PC and NGCC plants

This section contrasts the performance and costs for retrofit and new build options using two methods:

- **Comparing retrofitting at two existing plants**
  An analytical proof is presented in section 5.1 showing that the cost of abatement would be independent of the original unabated power plant efficiency for integrated retrofit (or new build) capture plants receiving the same electricity prices provided that the same capture technology with the same level of integration are used and that relevant site-specific factors are comparable.

- **Comparing retrofit options and new build plant options at an existing site**
  In the rest of this section a parametric model for retrofit and new build performance and costs that analyses and compares integrated and additional heat and power retrofits and new builds plant has been implemented as a spreadsheet. The default data values and results from the parametric model for a range of retrofit options are presented in tabulated form. A wider sensitivity analysis is also presented graphically.

5.1 Insensitivity to thermal efficiency for retrofit; sensitivity for replacement

An analytical proof that the theoretical carbon price to cover CCS costs is independent of thermal efficiency when comparing retrofit options for existing plants and illustration of when replacement with new build CCS plants can correspond to a lower carbon price.

The starting point for this analysis is the proof, given in Appendix 1, that the efficiency penalty for retrofitting post-combustion capture (and hence also the electricity output penalty – kWh/tCO_2 captured) is independent of power plant efficiency (i.e. would be identical for any sub-critical or supercritical steam plant with otherwise similar parameters).

As shown in Appendix 6 the cost of capture (which can be regarded as either the carbon price that would cover CCS or the cost of abatement) can then be calculated from the following equation. On the right hand side are the additional capital costs and operating costs for the capture plant, CO_2 transport/storage costs and also the reduced total revenue associated with the reduced amount of electricity normally available to sell after retrofit. This is balanced against the costs without capture on the left hand side, which include much higher carbon emission costs:

$$POE_n * N_n - e * N_n * COC - FC - N_n * vc \\ = POE_c * N_c * \frac{(n-\delta)}{\eta} - FCC - e * (1-c) * N_c * COC - N_c * e * c * vcc - FC - N_c * vc \tag{5.1}$$

Where:

Subscripts: n=no capture, c=CCS retrofitted

POE	\$/MWh	Time averaged price for electricity
N	hr	Annual operating hours
e	tCO_2/MWh	Time averaged specific emissions factor for plant

COC	$/tCO$_2$	Cost of carbon emissions
η	% LHV	Plant thermodynamic efficiency with no capture
δ	%point LHV	Capture penalty
FCC/FC	$/MW	Fixed charges for CCS retrofit / base plant (capital and fixed O&M)
c	-	Fraction of CO_2 captured
vcc/vc	$/tCO$_2$ / $/MWh	Specific variable costs for CCS / base plant

This equation can be simplified to give the following result, which does not contain the plant efficiency, only the efficiency penalty (which is independent of plant efficiency):

$$COC = \delta * \frac{POE}{fCO2 * c} + \frac{fcc}{N} + vcc \qquad (5.2)$$

Where:

fcc	$/(tCO$_2$/hr captured)	Specific fixed capital charges for CCS
fCO2	tCO$_2$/MWh	Specific emissions on a thermal basis for the fuel

The consequences of equation 5.2 for adding capture to power plants that have different efficiencies but otherwise similar site-specific characteristics are shown in Table 5.1. Less efficient plants produce more CO_2 and have a slightly lower relative power output after capture. But the costs per tonne of CO_2 avoided are the same in all cases. This means that it makes sense to look for other characteristics, such as space on site, access to CO_2 storage or load factor, when considering which existing plants to retrofit first, but not to discriminate on the grounds of efficiency unless the efficiency is so low as to justify replacement with a new plant with CCS (see below).

Table 5.1 Relative amounts of CO_2 to capture, capacity remaining and penalty per tonne of CO_2 capture for retrofit, compared to 38% LHV datum

LHV efficiency before retrofit	Relative amount of CO2 emissions to be handled for the same output before capture	Power after capture as fraction of original power	Relative MW penalty and total cost per tonne of CO2 avoided
36%	106%	75.0%	100%
38%	100%	76.3%	100%
40%	95%	77.5%	100%
42%	90%	78.6%	100%
44%	86%	79.5%	100%
46%	83%	80.4%	100%

It is worth noting that the above conclusion on retrofitting is notwithstanding, for otherwise similar plants, a higher cost per MW of electrical output of adding capture to the less efficient plant and, if the capital cost is assumed to be written off in both cases, a higher levelised cost of electricity (LCOE) generation. The important factor here is that different baselines also apply to the two retrofit cases and so the higher existing CO_2 emissions for the lower efficiency plant justify the greater expenditure.

Somewhat different arguments apply when comparing retrofitting capture at an existing lower-efficiency plant with the alternative of replacing it with a new build plant with higher efficiency, as in the following section. When calculating the costs of abatement for retrofit applications for which electricity prices are unknown it is necessary to derive average electricity costs for the same electricity output with CCS as for the original plant without CCS. This means that it is necessary to specify how reduced electrical energy output to the electricity network per unit fuel input is replaced after CCS is retrofitted at an existing plant. The same electricity output can be assumed to be achieved by:

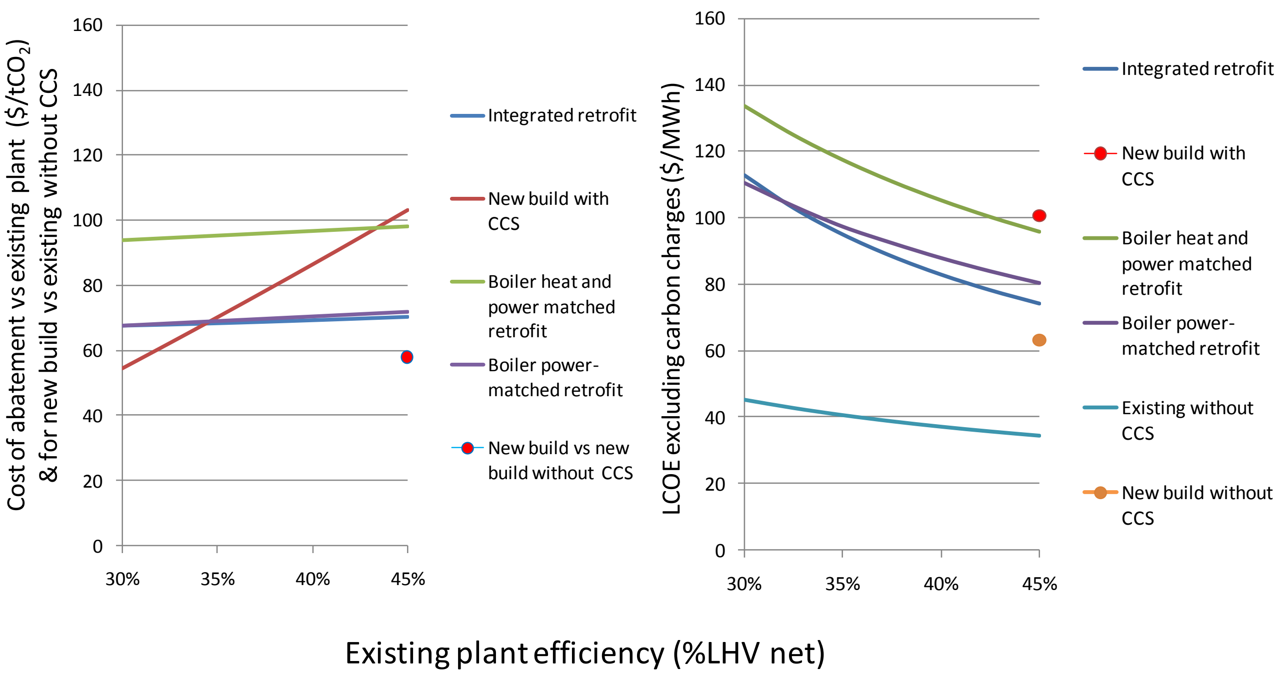
- building additional new plant with CCS elsewhere in the electricity network to make up the lost output (which is 'purchased' at cost to make up the original output, and give corresponding emissions with CCS); or
- providing additional plant on site to provide all of the required heat and power to operate capture equipment for the original and for the additional plant (heat and power matching); or
- providing additional plant on site that produces just enough power to compensate for the lost output and some heat (corresponding to the maximum possible conversion of the additional fuel into electricity), with the remaining heat coming from the existing plant's steam cycle.

As shown in Figure 5.1.1 overleaf, the larger amounts of CO_2 captured balance the additional costs to give a cost of abatement for retrofitting that is insensitive to the efficiency of the original plant. The cost of abatement for replacing an existing plant with a new build plant with CCS is, however, a strong function of the original plant efficiency, as shown in Figure 5.1.1 (a). Lower-efficiency plants have a relatively higher increase in electricity costs when capture is added so there is a greater chance that the cost of electricity from a retrofit to them will be higher than for a new build plant with CCS. Residual emissions (i.e. $kgCO_2$/MWh delivered) are also slightly higher for lower efficiency plants, although this is a secondary effect.

For the parameter values assumed for Figure 5.1.1, however, the threshold efficiency below which retrofit on these coal plants becomes unattractive is in the region of 35% LHV net (approximately 33% HHV net). Subsequent sensitivity studies for coal plants in section 5.3 are for a range of 35% to 45% LHV efficiency and so there are a limited proportion of cases where new build LCOE values are attractive compared to retrofits.

Additionally, even lower existing plant efficiencies would be required to give a cost of abatement lower than that for adding CCS to a new build plant that was going to be built anyway – see the value shown as a red circle in Figure 5.1.1 (a). It is important to remember, however, that just building new plants with CCS would not of itself reduce CO_2 emissions since this does not necessarily reduce CO_2 emissions from existing plants. Since this cost of abatement is indicative of the carbon prices that would be required to justify implementation of that CCS application, it is evident that higher carbon prices would probably be required to induce a reduction in CO_2 emissions from an existing fleet by either retrofitting or replacing existing plants than would be required to build additional new plants with CCS.

In principle as carbon prices were raised the first (i.e. lowest cost) emission reductions might be obtained by replacing very low-efficiency existing plants by new build plants with CCS. Above a certain efficiency level, however, where replacement became unattractive, retrofit would be equally attractive on all existing plants, or more accurately efficiency would have little or no inherent effect on the choice of subsequent retrofits as the carbon price was raised. Instead other, often site specific, factors would determine the relative economics of paying for CO_2 emissions or avoiding payment by retrofitting CCS.



(a) (b)

Figure 5.1.1 Effect of plant efficiency on cost abatement (a) and levelised cost of electricity without carbon charges (b) for coal plant retrofits and new coal with CCS
(for assumed parameter values see Section 5.4.1)

The ways in which these site-specific factors and also general factors, such as fuel costs and costs of capital, might affect the relative costs of electricity for new build and a range of retrofit options are illustrated by a sensitivity analysis in section 5.3.

5.2 Spreadsheet for parametric estimates of LCOE for post-combustion capture power plant retrofits and new build replacements

5.2.1 Spreadsheet structure

A spreadsheet has been written to implement parametric performance and cost calculations for retrofit and new build replacement options for adding CCS at an existing plant. The principal features are described below; a full listing is given in Appendix 8.

The spreadsheet has sections to calculate performance and costs for the following cases:

A. Existing plant with integrated capture retrofitted

B. New plant with integrated capture (see 5.2.2 below)

C. Retrofit with an additional plant providing heat and/or power
   C1. Retrofit with additional plant supplying 100% of heat requirements
   C2. Retrofit with an additional plant with specified fuel input

Analysis for the retrofit and new build integrated capture cases is relatively straightforward once the relevant data parameters have been specified since no significant variations in the configuration of the plant have been assumed for first order analysis of the type undertaken using this spreadsheet.

Two sets of similar and consistent calculation options are provided for the retrofit case using an additional plant to provide heat and/or power for the retrofit. The C1 procedures are provided for convenient analysis of the case when both heat and power are to be matched and exactly the same electricity output is to be maintained. This is done by varying the power-to-heat ratio to get the desired plant output using the Excel 'Goal Seek' function. In this the heat input required is calculated analytically, effectively varying two input parameters simultaneously.

All other retrofit options can be handled by the C2 procedures. In these cases there are no constraints on what the additional plant must achieve and all inputs can be specified. The Excel 'Goal Seek' function can, however, optionally be used to adjust the fuel input to achieve a given electricity output (i.e. power matching) or to have the additional plant meet 100% or some other specified fraction of the total heat load (i.e. heat matching).

5.2.2 Technical options for new build plant, as a counterfactual for retrofit

In the case of a new-build power plant used as a counterfactual in the spreadsheet it is assumed that the plant will be designed to meet the required power output with the design fuel(s) with a fully integrated CO_2 capture plant operating. Because the input data and the main results are all expressed on a per kg CO_2/per MW/ per MWh basis the calculated cost and performance values can be used for comparison with all retrofit options (with the assumption that cost are not materially affected by the slightly different plant sizes).

The issue of whether or not the new plant would also be designed to operate without capture, and in this case if the power output is to be increased, is not addressed, since the feasibility of this depends on the regulations that will be applied to the plant. The extent to which this is economically desirable and hence whether to make the necessary investments, including for enhanced power output, also depends on the market in which it will operate.

It is worth noting, however, that significant operational difficulties and/or costs will arise if some amount of operation without capture, or with capture plant operating at reduced performance, is not permitted. For example, activities such as start up, shutdown and possibly low load operation are likely to be significantly easier if short-term increases in CO_2 emissions are allowed by regulators. Commissioning, especially for early plants, will also be difficult if CO_2 capture has to be employed at all times.

In the extreme, regulatory limits on operation without capture could prevent effective integration with the base power plant. In a fully-integrated plant, it is expected that the capture plant will not start up until some time after the base power is operating and, hence, steam and power are available. Being able to operate CCS plants without capture obviously depends on environmental regulations applied to CCS in a particular jurisdiction. The environmental consequences of considering only the long term average emissions of CO_2 from a plant (over one or more years for example) are either neutral (because cumulative emissions over decades or longer determine climate outcomes) or beneficial (because the cost of achieving the same amount of CO_2 emission reduction will be cut with emission averaging).

5.2.3 Overview of calculation methods

(a) Integrated retrofit performance

Integrated retrofits to existing plant and capture on new build plant are characterised by an efficiency penalty, which is subtracted from the efficiency without capture to give the capture plant efficiency:

Efficiency with capture = Efficiency without capture – Efficiency penalty

Fuel thermal energy consumption follows from plant efficiency, with the corresponding CO_2 production based on the fuel specific emissions ($kgCO_2/MWh_{th}$). The specified capture level then gives CO_2 captured and stored and CO_2 emitted.

An arbitrary power output without capture is specified for the existing plant, which is reduced when capture is added in line with efficiency changes. A number of parameters (see example below) are calculated on the basis of this power output.

The new build plant is assumed to be sized to give the same power output with capture as the integrated retrofit capture case, although all specific parameters (i.e. per MW, per MWh) are not dependent on this value and so can be used for comparison with other retrofit cases.

(b) Link between capture heat load and loss in turbine power output

Heat integration between the steam cycle and the capture plant is modelled by two relationships.

The Coefficient of Performance for steam extraction, as defined below, which is assumed to apply for other levels of steam extraction as well as the integrated retrofit case defined by the overall efficiency penalty:

COPx = Heat for capture process / Drop in steam cycle (electricity) output

The value for COPx is calculated using the equation above, based on the specified values for efficiency penalty and capture plant auxiliary power and heat consumption.

Drop in net (electricity) output
= (Efficiency penalty / Efficiency without capture) x MW without capture

Drop in steam cycle output = Drop in net output – Capture plant power consumption

Heat for capture process = CO_2 captured x CO_2 heat requirements per tonne CO_2 captured

Work at the University of Edinburgh suggests that COPx values will be in the region of 5, but will depend on the specific details of the power plant and capture process (see Lucquiaud and Gibbins, 2010b). For comparison purposes it is important to note that the above process does anyway give consistency between capture options.

Allowance must also be made for the possible use of heat recovered from the capture process for condensate heating in the main steam cycle. This can give an increase in output corresponding to roughly 1 percentage point increase in efficiency for coal plants if all the condensate stream is being heated. There will, however, typically be no efficiency increase for combined cycle plants, because they do not generally use condensate/feedwater heating and the heat from the capture process is likely to be available at temperatures below the LP pinch in the HRSG, with excess heat already available. This boost is included in the overall efficiency penalty and COPx values, but if steam is not being extracted because an additional plant is being used (Case C in the spreadsheet) then a boost can still be achieved if recovered heat is used. A linear contribution is assumed based on the fraction of capture plant heat being supplied from other sources:

Efficiency increase = Efficiency boost x Heat from additional plant / Total heat for capture

The total heat for capture above applies to the capture plant capacity used for the existing power plant only since this can typically already supply all of the heat that can be used for condensate heating. Some further use of heat though integration with additional plants may be possible, but this will be project-specific and also probably a second-order effect.

(c) Cost calculations and comparison with new build options

An example of the way electricity costs are built up from different elements is show in Table 5.2.1 below.

The equivalent LCOE for the new build plant, for the period when both retrofitted and new plants are operating, may then be reduced as described in sections 4.2.3 and 4.2.4 if it is specified as having a higher load factor than a retrofitted plant and/or a longer economic life.

The equivalent LCOE for the new build plant (the LCOE that would have to be obtained over the same periods in time that the retrofit plant is operating) can be compared directly with the LCOE for retrofit values[17]. Differences can appear small so their significance is examined through two indicators:

- The comparative ROI for the retrofit plant capital costs if it is assumed that it receives the equivalent LCOE for the new build plant (with the latter then receiving the specified rate of return)

[17] Note, the equivalent new build LCOE value may differ for different retrofit options if the load factor correction applies because the SRMC for the retrofit then determines the maximum revenue for the extra time the new build plant is operating.

- A cost of abatement relative to the original plant being considered for retrofit, with additional power to get the same electrical output being bought or sold at the new build plant LCOE

Table 5.2.1 Example of electricity cost build up with capture

Electricity costs for existing plant with integrated retrofit		
Existing plant CAPEX (note 'with capture' basis)	\$/kW with capture	645
Capture plant CAPEX	\$/kW with capture	671
Total CAPEX	\$/kW with capture	1316
Capital charge rate - retrofit	%/yr	11.02%
Running hours per year - retrofit	hrs/yr	7008
Fuel costs	\$/MWh	32.3
Existing power plant CAPEX	\$/MWh	10.1
Existing power plant fixed costs	\$/MWh	9.2
Existing power plant variable costs	\$/MWh	6.5
Capture plant CAPEX	\$/MWh	10.5
Capture plant fixed OPEX	\$/MWh	1.91
Capture plant variable OPEX	\$/MWh	2.87
CO_2 emission costs	\$/MWh	5.3
Captured CO_2 T&S costs	\$/MWh	9.6
LCOE	\$/MWh	88.3
SRMC	\$/MWh	56.5
LCOE excluding CO_2 emission charges	\$/MWh	83.0

The cost of abatement would be most valid as a comparator if the same load factor and life were to apply to the existing plant with or without retrofit and to the new build plant. To the extent that this is unlikely it should be regarded as indicative only. Also because of this, and other factors such as different risk profiles and carbon price trajectories, the cost of abatement thus calculated should not be taken as an estimate of a carbon price to cover the cost of retrofit or to achieve any other 'real world' effect.

As an example, Figure 5.2.1 below, for natural gas retrofits, shows how relatively small changes in LCOE correspond, almost linearly, to larger swings in the cost of abatement and comparative ROI. This indicates that LCOE is a good indicator of economic performance; as such it will be the main reported variable in the sensitivity studies in section 5.5.

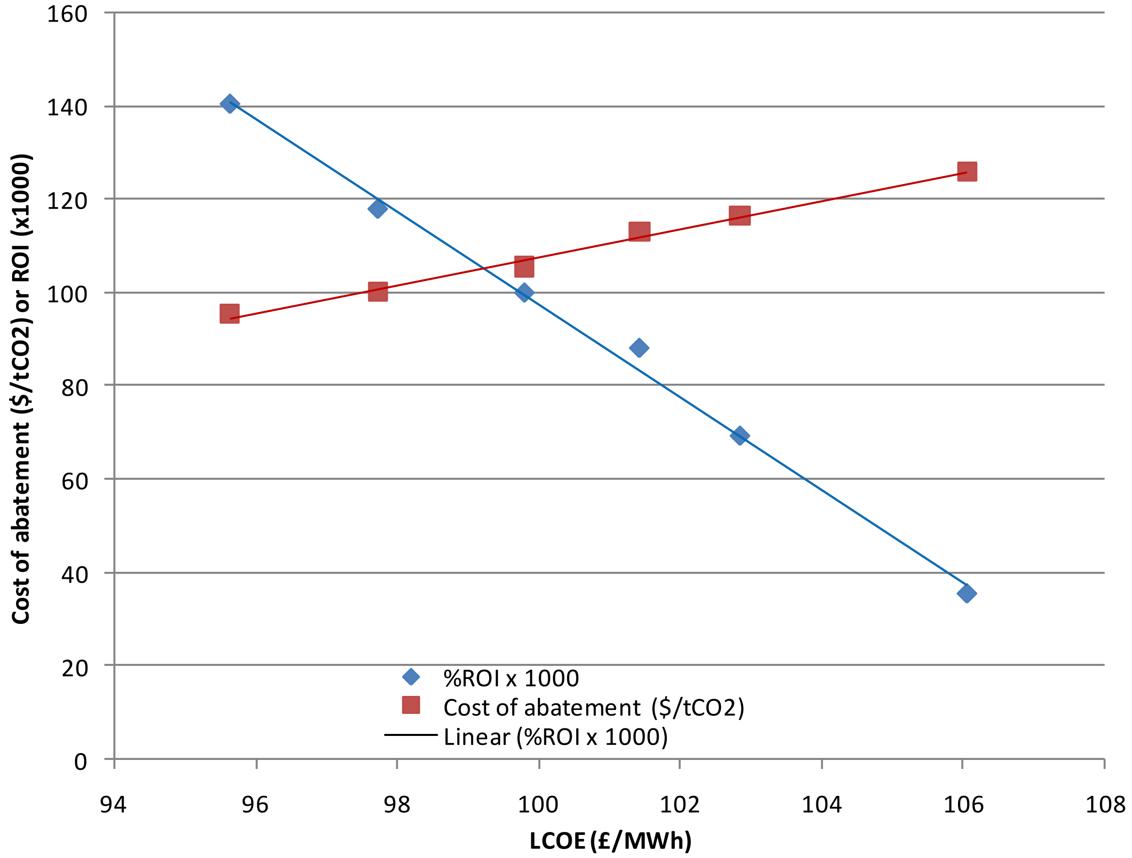


Figure 5.2.1 Variation in the cost of abatement and comparative ROI for a range of natural gas new build/retrofit options

(Points left to right (decreasing ROI, increasing cost of abatement) are respectively for: Integrated retrofit; GTCC power matched retrofit; New build; GTCC heat matched retrofit; Boiler heat and power matched retrofit; Boiler heat-matched retrofit)

5.3 Default data values for performance and cost calculations and comments on their selection and use

Performance-related parameters for retrofitted and new build capture power plants						
Parameter	Units	Indicative values				Comments
		Coal		Gas		
		New	Existing	New	Existing	
Fuel specific emissions	kgCO2/ MWh_th LHV	330	330	210	210	More precise values could be used if fuel is known
Efficiency without capture	%LHV	45%	38% 42%	59%	52% 56%	Existing coal plant efficiencies are for sub-critical plant with a re-bladed turbine (38%) and early supercritical steam plant (42%); median 40% and 54% values used for tabulated examples.
Power plant electricity output without capture	MW	-	-	-	-	An arbitrary value for the existing plant. The new plant is sized to have the same output with capture.
Efficiency penalty for integrated capture plant	percentage points	9%	9%	7%	7%	This penalty will if anything be higher for a retrofitted plant, but should be similar for retrofits to capture ready plants. Not a function of plant efficiency – see Appendix 1
Capture level for post-com capture plant		90%	90%	85%	85%	Typical values, need to be consistent with efficiency penalty
Compression and auxiliary power per tonne CO_2 captured	kWh/tCO2	135	135	170	170	Value required for retrofit to existing plant with additional heat/power source only, needs to be consistent with efficiency penalty
CO_2 capture heat requirements per tonne CO_2 captured	GJ/tCO_2	3.00	3.00	3.10	3.10	Based on the heat required by capture system (assumed to be steam, value allows for hot condensate returned), needs to be consistent with efficiency penalty. A partial check on the consistency is given by the calculated ratio between the electricity output loss and the capture plant heat requirement (COPx - Coefficient of Performance (heat supplied/power lost) for steam extraction). For well-integrated plants this is likely to be in the region of 5 for reboiler solvent-side temperatures around 120ºC.
Existing power plant efficiency boost for 100% heat recovery from capture plant with additional heat input	percentage points	N/A	1%	N/A	0%	This is the increase in a retrofitted steam plant's output that can obtained if steam extraction from the LP turbine cylinder for condensate heating is replaced by heat recovered from a CO_2 capture and compression equipment that has an additional heat input. This heat recovery is included in the efficiency penalty for an integrated retrofit of existing and new plant. It is not likely to be feasible to obtain significant benefits with combined cycle plants.

Economic parameters for retrofitted and new build capture power plants						
Parameter	Units	Indicative values				Comments
		Coal		Gas		
		New	Existing	New	Existing	
Fuel costs (LHV basis) (GJ values for information)	\$/MWh_th (\$/GJ LHV) (\$/GJ HHV)[18]	10 (2.8) (2.7)	10 (2.8) (2.7)	30 (8.3) (7.6)	30 (8.3) (7.6)	More precise values could be used if known; this is a key variable in determining electricity costs
Capital costs excluding capture-related costs, before capture basis (these can be on any consistent basis, i.e. overnight EPC, TIC etc.) No decommissioning costs are explicitly included – it can either be assumed that these are similar to the scrap value of the plant or the NPV of these could also be added to this capital cost.	\$/kW without capture	2000	500	1000	250	New plant costs are nominal values based on approximate current values but in a strongly-fluctuating market – see Figure 4.2. Existing plant capital costs are for work beyond the annual maintenance charges that would be required to keep the base power plant running for the assumed capture plant life (i.e. costs that would not be incurred if the plant was closed down instead of being retrofitted). These costs should not include items that would be included in the capture plant costs. They are assumed to be incurred at the time of retrofit.
Annual fixed charges for new plant, before capture basis	% of capital	2%	N/A	2%	N/A	Fixed annual costs such as labour, some maintenance items and (if included in the analysis) property taxes. Likely to be in range 1-3% of the capital costs above for new plant.
Annual fixed charges for retrofitted plant, before capture basis	\$/kW	N/A	50	N/A	25	Higher \$/kW values expected for retrofitted plants due to likely lower efficiency and greater age.
Variable costs for base power plant, before capture basis, per unit electricity supplied	\$/MWh	4	5	2	3	Variable operating costs such as increased maintenance, likely to be higher for retrofitted plant
Capital cost for capture plant, new build, on the same basis as the other plant capital costs.	\$/(kgCO_2/hr)	700	700	1500	1500	For capture equipment on new build plant this cost can be related to the capital costs for the basic power plant using the ratios for (capture plant \$/(kgCO_2/hr) to base plant \$/kWe) shown in Appendix 7 as approx. 0.2 to 0.4 for pulverised coal plants, 1.2 to 1.8 (2.6) for natural gas combined cycle plants. Capture equipment on retrofitted plant will probably be no lower in cost and may be somewhat higher, particularly for non-capture ready plants,

[18] Assuming HHV values are 5% higher for coal and 10% higher for natural gas

						due to the increased costs of having to work around existing plant. This increase can be characterised by a 'retrofit factor' but its value will obviously be very site and project specific; sensitivity values of 1 and 1.3 are used in this study.
Annual fixed costs for new capture plant only, related to CAPEX		2.00%	2.00%	2.00%	2.00%	Values in the range 1-3% are expected to cover maintenance and labour etc.
New capture plant non-energy OPEX, based on CO_2 captured	$/t$CO_2$	3.00	3.00	3.00	3.00	The principal element of this is expected to be the cost of solvent make-up and residue disposal and could vary significantly (e.g. depending on the solvent type).
CO_2 emission charge	$/t$CO_2$	50	50	50	50	This value has only a small effect on the differential economics of plants with high capture levels. A value is chosen which reflects the fact that CCS is in use and no sensitivity analysis is undertaken.
CO_2 transport and storage costs	$/t$CO_2$	10	10	10	10	This value will be project specific and may be mainly a fixed cost (i.e. for pipeline and injection infrastructure) rather than variable cost. Sensitivity values of $5, 10 and 20/t$CO_2$ are used in this study.
Interest rate	%	10.00%	10.00%	10.00%	10.00%	A rate of 5% is also used in the sensitivity analysis.
Plant life	years	25	25	20	20	A nominal 25 year economic life for coal, 20 for gas, with alternatively a sensitivity case of 15 year life for the retrofitted coal plant of 10 for retrofitted gas plant. With shorter retrofit life the LCOE can only be compared explicitly with a new plant by specifying a residual value for the new plant at the end of 15/10 years (against an assumed zero residual value for the retrofitted plant).
Residual value of new plant at end of retrofit life period (for cases where limited retrofit life is assumed – see previous row)	$/kW with capture	2000		1200		In cases where it is assumed the new build plant has a longer economic life, the assumed residual value for a new build capture plant at the end of the retrofit plant's economic life
Load factor for new plant, assumed to be all at full output		80%/ 40%	80%/ 40%	80%/ 40%	80%/ 40%	A 'high' load factor case of 80% is assumed, also a lower factor of 40%. An 80% load for the new build and a 40% load for the retrofit is also compared (assuming the former receives the SRMC of the retrofit for 40% of the time).

Performance parameters for additional plant that may optionally be used to supply heat and/or power for capture retrofits				
Coal and gas from this point on refers to the fuel used in the additional plant, which can be different from the fuel used in the main plant, additional heat and power sources are also assumed to be utilised only for capture retrofits.				
		Coal	Gas	Comments
Additional plant fuel specific emissions	$kgCO_2$/ MWh_th LHV	330	210	More precise values could be used if fuel is known
Additional plant energy utilisation factor Boiler + steam turbine Gas turbine combined cycle (GTCC)	%LHV	 90% -	 90% 85%	This is the percentage of the heat content of the fuel that is recovered as heat or electricity. The main loss for a heat-matched CHP system will be the stack losses, assumed to be slightly higher for a natural gas combined cycle (so 85% EUF) than for boilers (90% EUF)
Capture level for additional plant Boiler GTCC		 90% -	 90% 85%	This should be consistent with the capture levels for the existing plant if low overall emissions are to be achieved.
Additional compression and auxiliary power per tonne CO_2 captured Boiler + steam turbine GTCC	kWh/tCO_2	 135 -	 135 170	Needs to be consistent with the values used for the existing plant or comparison with an integrated retrofit will be skewed.
Additional plant CO_2 heat requirements per tonne CO_2 captured Boiler + steam turbine GTCC	GJ/tCO_2	 3.00 -	 3.00 3.10	Needs to be consistent with the values used for the existing plant or comparison with an integrated retrofit will be skewed.
Additional plant power/heat ratio Boiler + steam turbine GTCC		 0.5 -	 0.5 1.0	This value may be specified to characterise the additional heat/power source or alternatively it may be calculated automatically in the special case that the exact heat and power required by the capture plant(s) is supplied so that the exported electricity is unchanged after retrofit. The most efficient retrofit solutions are obtained when this value is as high as possible, consistent with the heat temperature required (approximately 1 for natural gas CHP -see Figure 3.1, 0.5 for coal CHP).
Additional plant fuel input	MW_th	Can specify any value, or calculate to just meet heat and power requirements		This value will be specified in all cases except the special case where the exact heat and power required by the capture plant(s) is supplied so that the exported electricity is unchanged after retrofit. It can be adjusted automatically in the Excel spreadsheet to give a desired outcome (e.g. maintain the electricity output at a desired value, match the total heat input etc.)

Economic parameters for additional plant that may optionally be used to supply heat and/or power for capture retrofits				
		Coal	Gas	
Economic parameters for additional plant for this type of retrofit				These are same parameters as for the integrated retrofits above, but possibly with different values for a retrofit using an additional heat/power source.
Additional plant fuel costs (LHV basis)	\$/MW_th	10	30	This may be a different fuel from that used in the existing plant that is being retrofitted.
Additional CHP plant costs, based on fuel input Boiler + steam turbine Gas turbine combined cycle (GTCC)	\$/kW_th	 900 -	 200 590	If a boiler is used to supply the full heat load for a retrofitted capture unit and also the capture plant for this additional plant the heat input will be of the order of 50% of that of the existing plant and a gas turbine will be around 100% of the heat input. Capital costs will therefore be comparable to those of a new plant (assuming lack of LP turbines, condensers etc. offset by non-standard design and complexity of heat delivery) or slightly lower, scaled by plant efficiency to allow for the kW_th basis. A relatively small heat input can be obtained if only the lost power is replaced, with some of the heat, with a possible increase in capital costs due to the scale, counterbalanced by the simplicity if a small gas turbine system is used.
Annual fixed costs for additional plant, related to CAPEX		2%	2%	Expected to be similar to new build plant
Variable costs for additional plant, related to fuel input	\$/MWh_th	1.8	1.2	Expected to be similar to new build plant (to be scaled for heat input based on efficiency)
Capital cost for additional plant capture plant, including all charges up to first day of operation Boiler + steam turbine GTCC	\$/(kgCO_2/hr)	 700 -	 700 1500	Expected to be similar to new build plant, but possibly some scope for shared capital cost with retrofitted plants through putting additional CHP plant emission through the main capture unit – e.g. via duct firing, turbine flue gas to boiler wind-box.
Annual fixed costs for additional plant capture plant related to CAPEX		2%	2%	Expected to be similar to new build plant
Additional plant capture plant non-energy OPEX, based on CO_2 captured	\$/tCO_2	3	3	Expected to be similar to new build plant

5.4 Comparison of selected retrofit and new build options

5.4.1 Coal-only options

Table 5.4.1a Performance for selected coal-only retrofit options

Performance with capture	Units	Existing plant without capture	Integrated retrofit	New build	Boiler heat and power matched retrofit	Boiler power-matched retrofit
Power plant efficiency with capture	%LHV	40.0%	31.0%	36.0%	27.5%	31.7%
Power plant electricity output with capture	MW	800.0	620.0	620.0	800.0	800.0
Power plant fuel input	MWth	2000.0	2000.0	1722.2	2906.6	2521.4
Additional plant power/heat ratio					0.134	0.500
Additional plant fuel input rate	MWth				906.6	521.4
CO2 produced	tCO2/hr	660.0	660.0	568.3	959.2	832.1
CO2 emissions with capture	tCO2/hr	660.0	66.0	56.8	95.9	83.2
Specific emissions with capture	kgCO2/MWh		106.5	91.7	119.9	104.0
CO2 captured	tCO2/hr		594.0	511.5	863.3	748.9
CO2 captured per unit of electricity	kgCO2/MWh		958.1	825.0	1079.1	936.1
Power plant output as a percentage of the original power			77.5%	80.0%	100.0%	100.0%
Power generated by additional plant as percentage of MW out					12.1%	19.6%
Total capture heat requirement	MWth		495	426.25	719.4	624.0
Additional plant heat output	MWth				719.4	312.8
Existing plant heat output as fraction of integrated retrofit			100.0%		0.0%	62.9%
Efficiency of marginal power vs integrated retrofit	%LHV				19.9%	34.5%

An integrated retrofit is contrasted with a new build capture plant, a heat and power matched additional low-pressure boiler plant with a back-pressure turbine (which maintains the site output and avoids the need to extract steam from the existing plant), and a high-pressure boiler which is power-matched (to maintain site output but only provides part of the steam required). This last option, which achieves much better performance than the low-pressure boiler, requires an additional fuel input of around 25%. On a multi-unit site it may therefore be appropriate to provide an additional such unit for every four (in this case) existing units, with flexibility to extract varying amounts of steam, including possibly clutched LP turbines. The 'efficiency of the marginal power', the extra power beyond that for an integrated retrofit that is generated because of the use of the additional plant, should ideally be close to that of the integrated retrofit or new build plants with capture.

Table 5.4.1b Economic parameters for selected coal-only retrofit options

(80% load factor and 25 year life for all, median 40% LHV efficiency for existing plant, other values default, note that 'Total CAPEX' is the total capital requirement including interest during construction and all other charges.)

Electricity costs for with capture	Units	Existing plant without capture	Integrated retrofit	New build	Boiler heat and power matched retrofit	Boiler power-matched retrofit
Total CAPEX	\$/kW with capture	0	1316	3078	2275	1742
Capital charge rate - retrofit	%/yr		11.02%	11.02%	11.02%	11.02%
Running hours per year - retrofit	hrs/yr		7008	7008	7008	7008
Fuel costs	\$/MWh	25.0	32.3	27.8	36.3	31.5
Existing power plant CAPEX	\$/MWh		10.1	39.3	7.9	7.9
Existing power plant fixed costs	\$/MWh		9.2	7.1	7.1	7.1
Existing power plant variable costs	\$/MWh	7.1	6.5	5.0	5.0	5.0
Capture plant CAPEX	\$/MWh	5.0	10.5	9.1	27.9	19.5
Capture plant fixed OPEX	\$/MWh		1.9	1.6	5.1	3.5
Capture plant variable OPEX	\$/MWh		2.9	2.5	5.3	4.0
CO2 emission costs	\$/MWh	41.3	5.3	4.6	6.0	5.2
Captured CO2 T&S costs	\$/MWh		9.6	8.3	10.8	9.4
LCOE	\$/MWh	78.4	88.3	105.2	111.4	93.1
SRMC	\$/MWh	78.4	56.5	48.1	63.4	55.1
Cost of abatement based on original power output	\$/tCO2		69.3	86.6	96.8	70.4
Return on capital investment for electricity price equal to LCOE of new plant	%		19.8%	10.0%	7.7%	15.5%

The high capital cost of new coal plant is a major factor in electricity costs, even at this relatively high assumed load factor. This is not offset by the higher efficiency of the new build plant, which has higher cost for the assumed data. The low-pressure boiler additional plant retrofit is penalised by high costs and also by low efficiency. The high-pressure power-matched additional plant retrofit achieves a good efficiency and relatively low overall capital costs. Within the uncertainty of the data provided it appears that the high-pressure power-matched option may be comparable to an integrated retrofit and is anyway likely to be the more cost-effective option if the site power output is to be maintained. Steam extraction from the retrofitted plant falls by about ⅓ of the integrated retrofit value in the high-pressure power-matched retrofit case (so perhaps to approximately ⅓ of the steam flow into the turbine LP cylinders, rather than around ½ of the steam flow into the turbine LP cylinders).

5.4.2 Coal plus additional gas plant options

Table 5.4.2a Performance for selected coal retrofit and new build options with additional gas plant for retrofits

Performance results with capture	Units	Existing plant without capture	Integrated retrofit	New build coal	New build gas	Boiler heat and power matched retrofit	Boiler heat-matched retrofit	GTCC power matched retrofit	GTCC heat matched retrofit
Power plant efficiency with capture	%LHV	40.0%	31.0%	36.0%	52.0%	28.8%	27.1%	33.5%	38.2%
Power plant electricity output with capture	MW	800.0	620.0	620.0	620.0	800.0	722.8	800.0	1459.9
Power plant fuel input	MWth	2000.0	2000.0	1722.2	1192.3	2774.3	2666.7	2391.0	3824.6
Additional plant power/heat ratio						0.130	0.000	1.000	1.000
Additional plant fuel input rate	MWth					774.3	666.7	391.0	1824.6
CO2 produced	tCO2/hr	660.0	660.0	568.3	250.4	822.6	800.0	742.1	1043.2
CO2 emissions with capture	tCO2/hr	660.0	66.0	56.8	37.6	82.3	80.0	78.3	123.5
Specific emissions with capture	kgCO2/MWh		106.5	91.7	60.6	102.8	110.7	97.9	84.6
CO2 captured	tCO2/hr		594.0	511.5	212.8	740.4	720.0	663.8	919.7
CO2 captured per unit of electricity	kgCO2/MWh		958.1	825.0	343.3	925.4	996.1	829.7	630.0
Power plant output as a percentage of the original power			77.5%	80.0%	88.1%	100.0%	90.3%	100.0%	182.5%
Power generated by additional plant as percentage of MW out						10.0%	0.0%	20.8%	53.1%
Heat requirement	MWth		495.0	426.3	183.3	617.0	600.0	555.1	775.5
Additional plant heat output	MWth					617.0	600.0	166.2	775.5
Existing plant heat output as fraction of integrated retrofit			100.0%			0.0%	0.0%	78.6%	0.0%
Efficiency of marginal power vs integrated retrofit	%LHV					23.2%	15.4%	46.0%	46.0%

With the default fuel, capital and other costs used for natural gas plants in this study it appears to be economically viable to use additional plants fuelled by natural gas in some cases (see also Table 5.4.2b below). Although natural gas is more expensive (a factor of 3 compared to coal on a heat input basis has been assumed as the default) this is offset by the greater efficiency of GTCC plants and the lower carbon content of natural gas. This leads to a significantly higher efficiency than the coal-only cases for the GTCC additional plant options. The gas boiler options gain no significant efficiency advantage, however. Because of the higher duty for the GTCC additional plant the heat matched retrofit option has the highest overall thermal efficiency, but this is well below that for the new build GTCC plant and, with the default values used, this does not offer such an economically competitive option as the power matched GTCC retrofit.

For the power matched GTCC additional plant retrofit steam extraction rates do not fall as much as for the high-pressure coal boiler case in Table 5.4.1a. The method for implementing this additional plant retrofit option could, however, be somewhat different since reasonable efficiencies can be obtained at much smaller sizes for natural gas GTCC plant, allowing a dedicated GTCC CHP unit to be used with each existing coal-fired boiler on-site. As well as improving a unit's ability to operate independently, this 1:1 arrangement might also allow flue gas integration with the boiler (although this option is not specifically covered here) with GTCC exhaust gas being used to replace secondary air in the boiler. This would save on capture plant costs and overall capture energy requirements and might give a slight gain in thermal efficiency.

Table 5.4.2b Economic parameters for selected coal retrofit and new build options with additional gas plant for retrofits

(80% load factor and 25 year life for all, including gas new build, median 40% LHV efficiency for existing plant, other values default; cost of abatement based on unabated coal or gas plant as indicated, which is assumed to have the same power output as the plant with capture so no make-up power costs need to be considered.)

Electricity costs for with capture	Units	Existing plant without capture	Integrated retrofit	New build coal	New build gas	Boiler heat and power matched retrofit	Boiler heat-matched retrofit	GTCC power matched retrofit	GTCC heat matched retrofit
Total CAPEX	$/kW with capture	0	1316	3078	1650	1341	1435	1439	1631
Capital charge rate - retrofit	%/yr		11.02%	11.02%	11.02%	11.02%	11.02%	11.02%	11.02%
Running hours per year - retrofit	hrs/yr		7008	7008	7008	7008	7008	7008	7008
Fuel costs	$/MWh	25.0	32.3	27.8	57.7	54.0	55.3	39.7	51.2
Existing power plant CAPEX	$/MWh		10.1	39.3	17.8	7.9	8.7	7.9	4.3
Existing power plant fixed costs	$/MWh		9.2	7.1	3.2	7.1	7.9	7.1	3.9
Existing power plant variable costs	$/MWh	7.1	6.5	5.0	2.3	5.0	5.5	5.0	2.7
Capture plant CAPEX	$/MWh	5.0	10.5	9.1	8.1	13.2	13.9	14.8	21.3
Capture plant fixed OPEX	$/MWh		1.9	1.6	1.5	2.4	2.5	2.7	3.9
Capture plant variable OPEX	$/MWh		2.9	2.5	1.0	3.9	4.1	3.1	3.4
CO_2 emission costs	$/MWh	41.3	5.3	4.6	3.0	5.1	5.5	4.9	4.2
Captured CO_2 T&S costs	$/MWh		9.6	8.3	3.4	9.3	10.0	8.3	6.3
LCOE	$/MWh	78.4	88.3	105.2	98.1	108.0	113.4	93.4	101.3
SRMC	$/MWh	78.4	56.5	48.1	67.5	77.4	80.5	60.9	67.9
Cost of abatement based on original power output + new coal	$/t$CO_2$		69.3	86.6		91.0	98.1	70.6	76.9
Return on capital investment for electricity price equal to LCOE of new coal plant with CCS	%		19.8%	10.0%		8.3%	4.9%	16.4%	12.0%
Cost of abatement based on original power output + new gas	$/t$CO_2$		67.6		75.8	91.0	97.3	70.6	83.1
Return on capital investment for electricity price equal to LCOE of new gas plant with CCS	%		15.8%		10.0%	3.2%	-1.0%	12.6%	8.4%

5.4.3 Selected gas-only retrofit options

Table 5.4.3a Performance for selected gas-only retrofit options

Performance	Units	Existing plant without capture	Integrated retrofit	New build	Boiler heat and power matched retrofit	Boiler heat-matched retrofit	GTCC power matched retrofit	GTCC heat matched retrofit
Power plant efficiency with capture	%LHV	54.0%	47.0%	52.0%	43.0%	41.8%	46.9%	46.8%
Power plant electricity output with capture	MW	800.0	696.3	696.3	800.0	747.2	800.0	1086.3
Power plant fuel input	MWth	1481.5	1481.5	1339.0	1861.8	1788.2	1704.7	2320.8
Additional plant power/heat ratio					0.190	0.000	1.000	1.000
Additional plant fuel input rate	MWth				380.3	306.7	223.2	839.4
CO2 produced	tCO2/hr	311.1	311.1	281.2	391.0	375.5	358.0	487.4
CO2 emissions with capture	tCO2/hr	311.1	46.7	42.2	54.7	53.1	53.7	73.1
Specific emissions with capture	kgCO2/MWh		67.0	60.6	68.3	71.1	67.1	67.3
CO2 captured	tCO2/hr		264.4	239.0	336.3	322.4	304.3	414.3
CO2 captured per unit of electricity	kgCO2/MWh		379.8	343.3	420.4	431.5	380.4	381.4
Power plant output as a percentage of the original power			87.0%	88.1%	100.0%	93.4%	100.0%	135.8%
Power generated by additional plant as percentage of MW out					6.8%	0.0%	11.9%	32.8%
Heat requirement	MWth		227.7	205.8	287.6	276.0	262.0	356.7
Additional plant heat output	MWth				287.6	276.0	94.9	356.7
Existing plant heat output as fraction of integrated retrofit			100.0%		0.0%	0.0%	73.4%	0.0%
Efficiency of marginal power vs integrated retrofit	%LHV				27.3%	16.6%	46.5%	46.5%

With the default values used for natural gas power plant cases the efficiency of a new build capture plant is significantly higher than all retrofit options. The integrated capture retrofit option efficiency is equalled by that of the GTCC power matched and heat matched retrofits. The last increases power output from the site by ⅓. The power-matched GTCC retrofit would still require a high level of integration with the main steam cycle, with a reduction of only around ¼ in the amount of steam needing to be extracted.

Despite assuming benefits in energy utilisation factor and capture energy consumption because of lower excess air levels in the boiler retrofit cases, efficiencies are significantly reduced when a boiler is used. Lower capital costs are also assumed for the additional plant and its associated capture plant in the boiler options, although this is offset to some extent by the increased amounts of CO_2 to be captured. But the CAPEX component of the electricity costs is low for most of the retrofits and differences are therefore relatively unimportant, except for the

GTCC heat matched retrofit. The economic performance of this unit is obviously sensitive to the capital costs assumed for the large GTCC CHP unit, as is that for the new build plant for similar reasons.

LCOE values for all cases are dominated by fuel costs, but the low fuel costs for the new build plant are still offset by its assumed higher capital cost to give a poorer overall economic performance than the integrated retrofit to an existing plant and the GTCC power matched retrofit. The latter is effectively also an integrated retrofit with an added smaller GTCC CHP unit. The slightly lower capital costs of the boiler heat and power matched retrofit will improve its performance relative to the GTCC option at lower load factors and it may also be possible to integrate this unit with the main steam turbine for capture by using GT exhaust as a source for oxygen for the boiler (perhaps by duct firing).
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Table 5.4.3b Economic performance for selected gas-only retrofit options

Electricity costs	Units	Existing plant without capture	Integrated retrofit	New build	Boiler heat and power matched retrofit	Boiler heat-matched retrofit	GTCC power matched retrofit	GTCC heat matched retrofit
Total CAPEX	$/kW with capture	0	857	1650	904	935	985	1212
Capital charge rate - retrofit	%/yr		11.75%	11.75%	11.75%	11.75%	11.75%	11.75%
Running hours per year - retrofit	hrs/yr		7008	7008	7008	7008	7008	7008
							0	0
Fuel costs	$/MWh	55.6	63.8	57.7	69.8	71.8	63.9	64.1
Existing power plant CAPEX	$/MWh		4.8	19.0	4.2	4.5	4.2	3.1
Existing power plant fixed costs	$/MWh	3.6	4.1	3.2	3.6	3.8	3.6	2.6
Existing power plant variable costs	$/MWh	3.0	3.4	2.3	3.0	3.2	3.0	2.2
Capture plant CAPEX	$/MWh		9.5	8.6	11.0	11.2	12.3	17.2
Capture plant fixed OPEX	$/MWh		1.6	1.5	1.9	1.9	2.1	2.9
Capture plant variable OPEX	$/MWh		1.1	1.0	1.8	1.8	1.5	2.1
CO2 emission costs	$/MWh	19.4	3.4	3.0	3.4	3.6	3.4	3.4
Captured CO2 T&S costs	$/MWh		3.8	3.4	4.2	4.3	3.8	3.8
LCOE	$/MWh	81.6	95.7	99.8	102.9	106.1	97.7	101.4
SRMC	$/MWh	78.0	75.6	67.5	82.3	84.7	75.6	75.6
Cost of abatement based on original power output	$/tCO2		95.6	105.6	116.4	125.9	100.3	113.2
Return on capital investment for electricity price equal to LCOE of new gas plant	%		14.1%	10.0%	6.9%	3.5%	11.8%	8.8%

5.5 Sensitivity analysis for economic performance of retrofit options

The following figures show the economic performance of a range of capture options as certain key data parameters are varied.

Only the more promising retrofit options are included:

(a) Integrated retrofit

(b) Power matched retrofit with a high-efficiency natural GTCC CHP plant (labelled as ‘GTCC additional plant’)

(c) Power and heat matched retrofit with a natural gas boiler and back pressure turbine (labelled as ‘Gas boiler additional plant’)

Option (a) above has a reduced power output after retrofit since all of the heat and power for capture are supplied from the existing plant.

Options (b) and (c) both maintain the same power output from the site. Option (b) will require that significant amounts of steam are still extracted from the existing plant to supply post-combustion capture plant heat requirements.

Also shown are new build capture plant options using the same fuel as the existing plant.

Default data values are used throughout except as noted in the figure legends or captions.

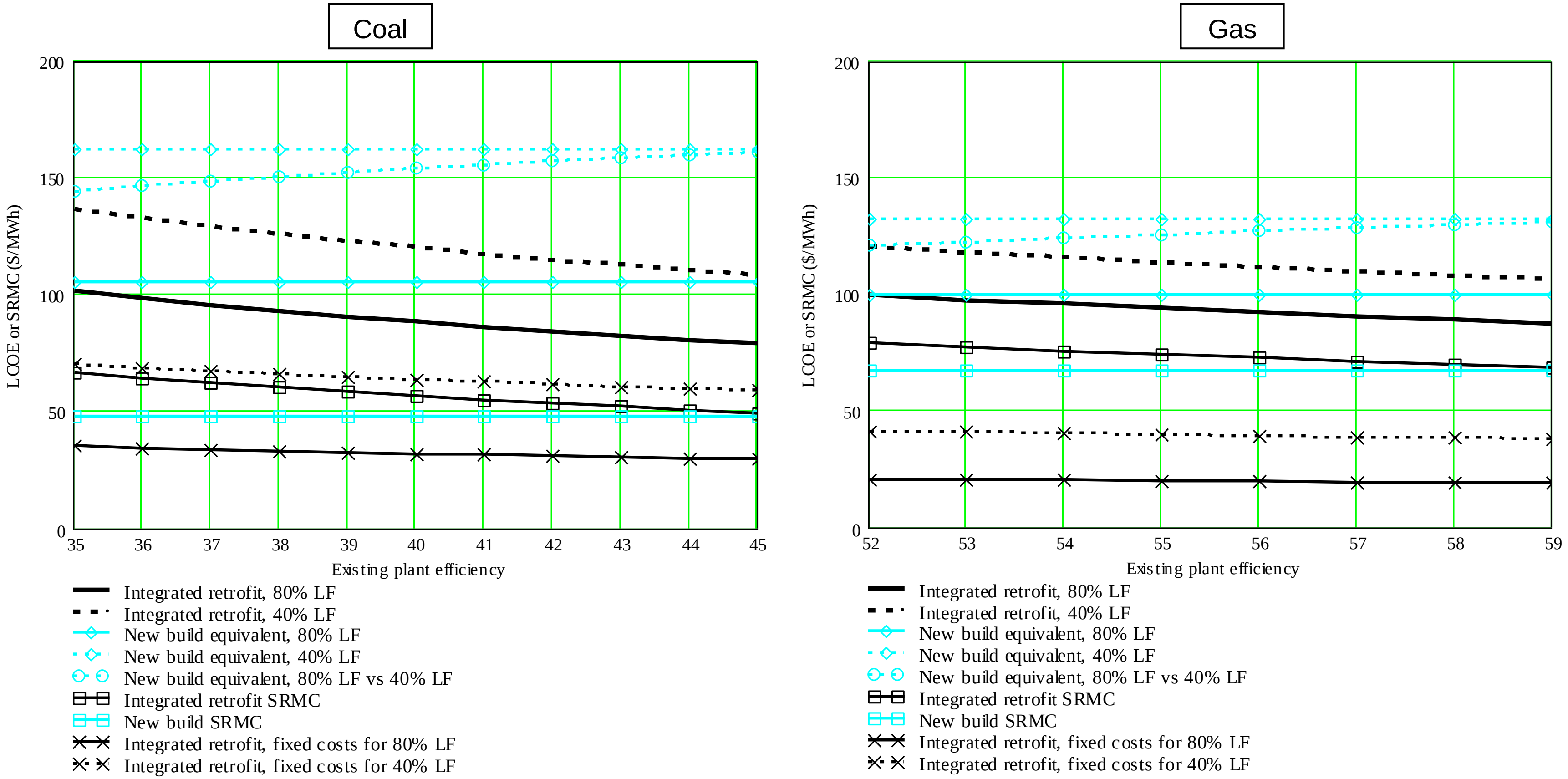


Figure 5.5.1 Variation in LCOE with existing plant efficiency at 40% and 80% load factors

Existing plant efficiency directly affects the efficiency of the plant when retrofitted with capture and hence both the variable and (to a lesser extent) the fixed costs on a per MWh basis. Particularly at high load factors, the higher costs for a lower-efficiency existing plant will tend to make a new build plant relatively more attractive. At low load factors for both retrofit and new plants the lower capital cost for a retrofit tends to offset even a low efficiency. If the new build plant achieves a significantly higher load factor than the retrofitted plant (80% vs 40% shown in Figure 5.5.1) and the new build plant was paid just below the significantly-higher SRMC of a low-efficiency retrofitted plant while the latter was not operating then this would also tend to make the new build option more competitive, although still not cheaper than an integrated retrofit for the default data values selected.

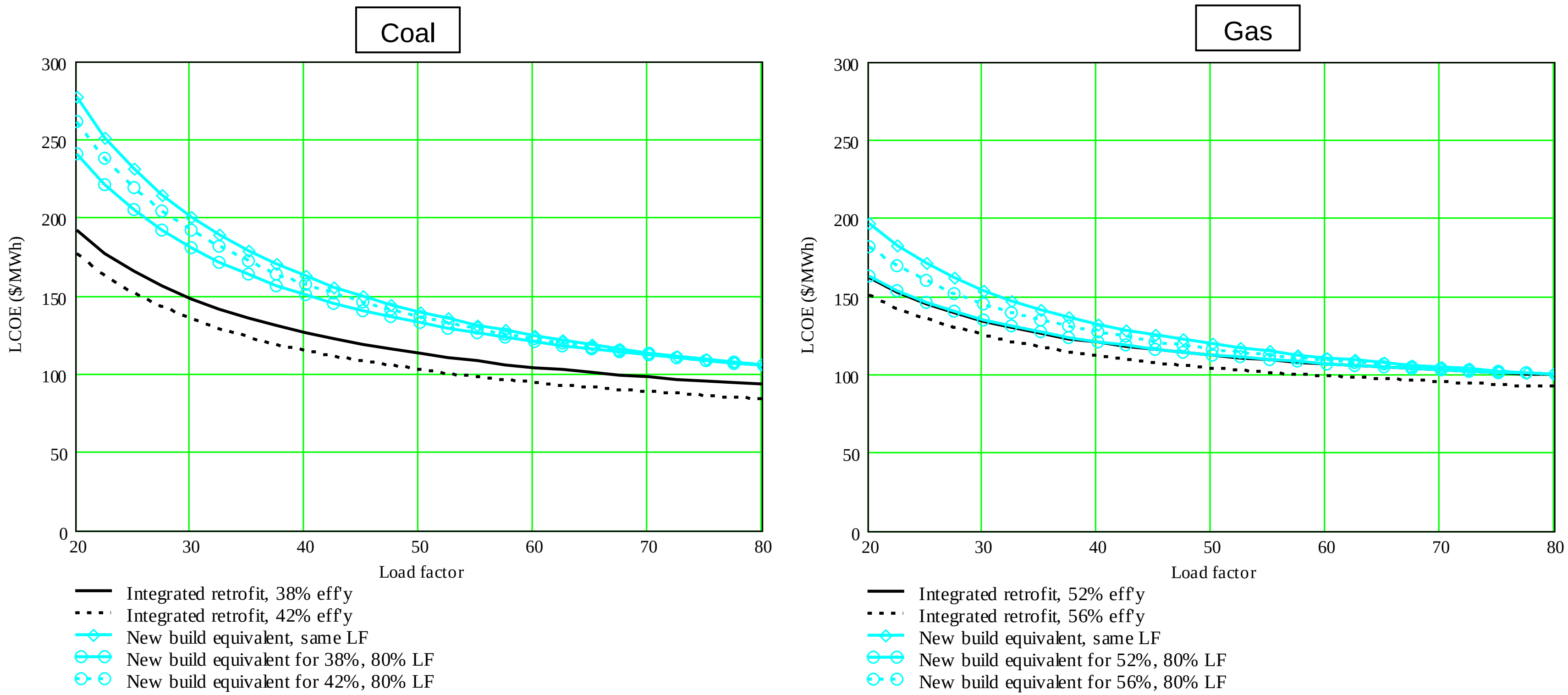


Figure 5.5.2 Variation in LCOE with load factor

The LCOE increases for all plant options with reducing load factor but the likely higher capital cost of a new build plant would make it relatively more sensitive than a retrofit. Even if the new build plant achieves a significantly higher load factor (constant 80%) than the retrofitted plant and the new build plant was paid just below the SRMC of a retrofitted plant while the latter was not operating then this additional income would still not compensate for reduced capital cost for the retrofitted plant for the values considered here – i.e. LCOE values are still higher than those for the integrated retrofits. In this case, however, the new build does relatively better (i.e. achieves lower LCOE values) if the efficiency of the alternative retrofitted plant is lower.

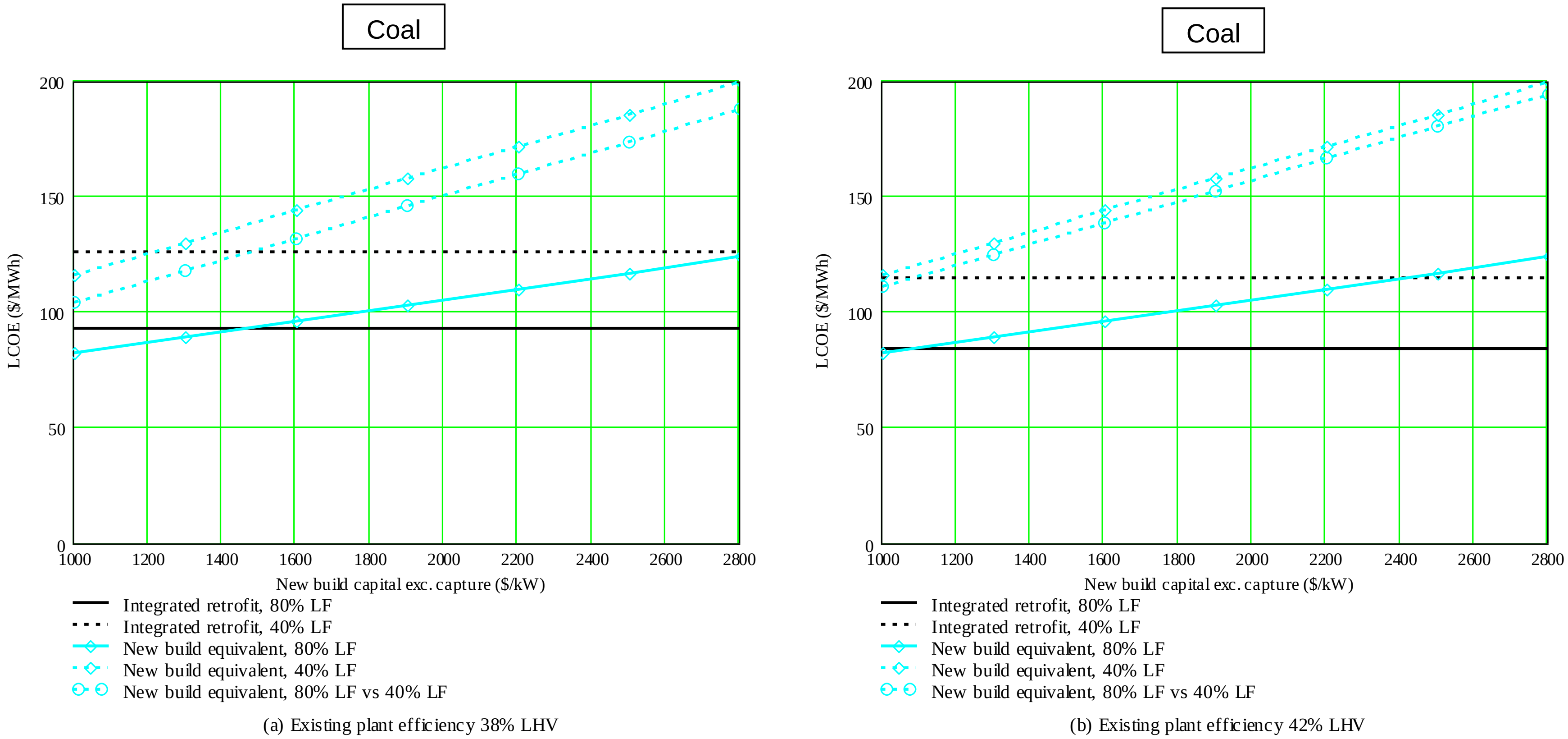
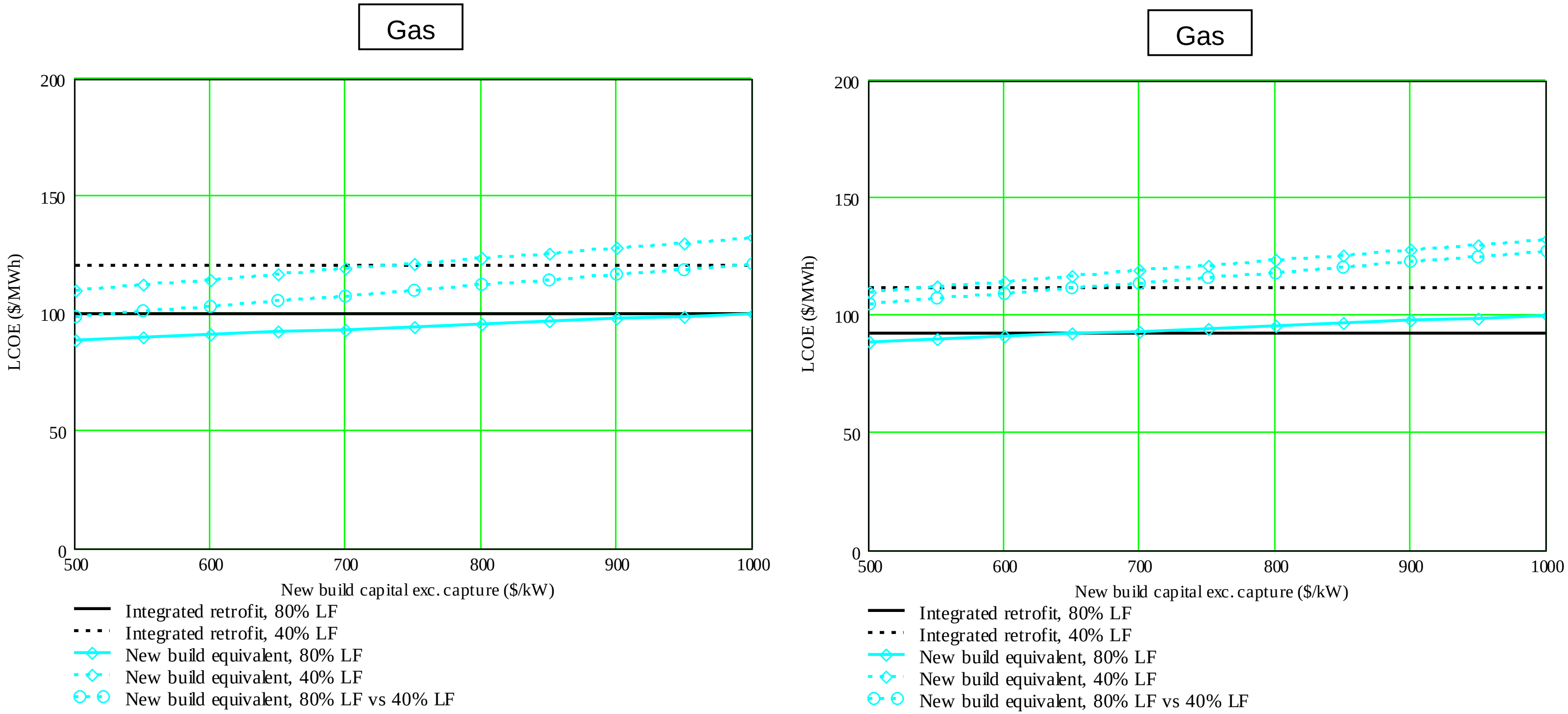


Figure 5.5.3a Variation in LCOE for coal with new plant capital cost for different load factors and retrofitted plant efficiencies

For the set of default values used, including 10% interest rates, capital costs for a new plant at 80% load factor to give the same equivalent LCOE as an integrated retrofit would need to be in the region of 1500 $/kW for an existing plant efficiency of 38% LHV (i.e. late-generation sub-critical), and 1100 $/kW for an existing plant efficiency of 42% LHV (i.e. early-generation supercritical).



(a) Existing plant efficiency 52% LHV

(b) Existing plant efficiency 56% LHV

Figure 5.5.3b Variation in LCOE for gas with new plant capital cost for different load factors and retrofitted plant efficiencies

For the set of default values used, including 10% interest rates, capital costs for a new plant at 80% load factor to give the same equivalent LCOE as an integrated retrofit would need to be in the region of 1000 $/kW for an existing plant efficiency of 52% LHV and 700 $/kW for an existing plant efficiency of 56% LHV.

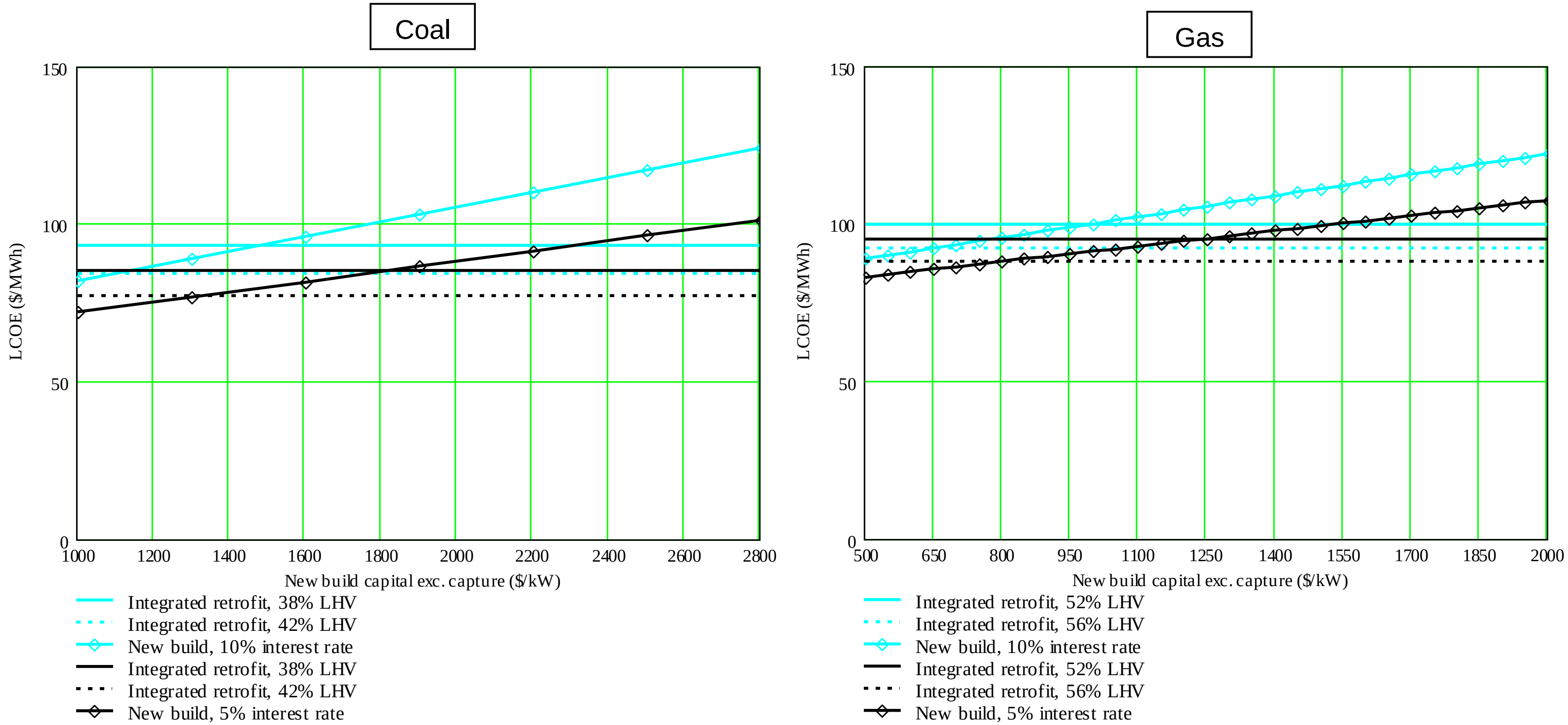


Figure 5.5.4 Variation in LCOE with new plant capital cost for different interest rates and retrofitted plant efficiencies

With 5% interest rate, capital costs for a new coal plant at 80% load factor to give the same equivalent LCOE as an integrated retrofit can increase beyond the values for 10% interest rate, rising to be in the region of 1850 $/kW for an existing plant efficiency of 38% LHV and 1350 $/kW for an existing plant efficiency of 42% LHV, but still below the default value of 2000 $/MWh. Similar trends are observed for natural gas plants, although with a smaller shift due to the proportionally lower capital costs. LCOE crossover values for gas cases are close to the 1000 $/MWh default value for new build power plants capital costs at 5% interest rates.

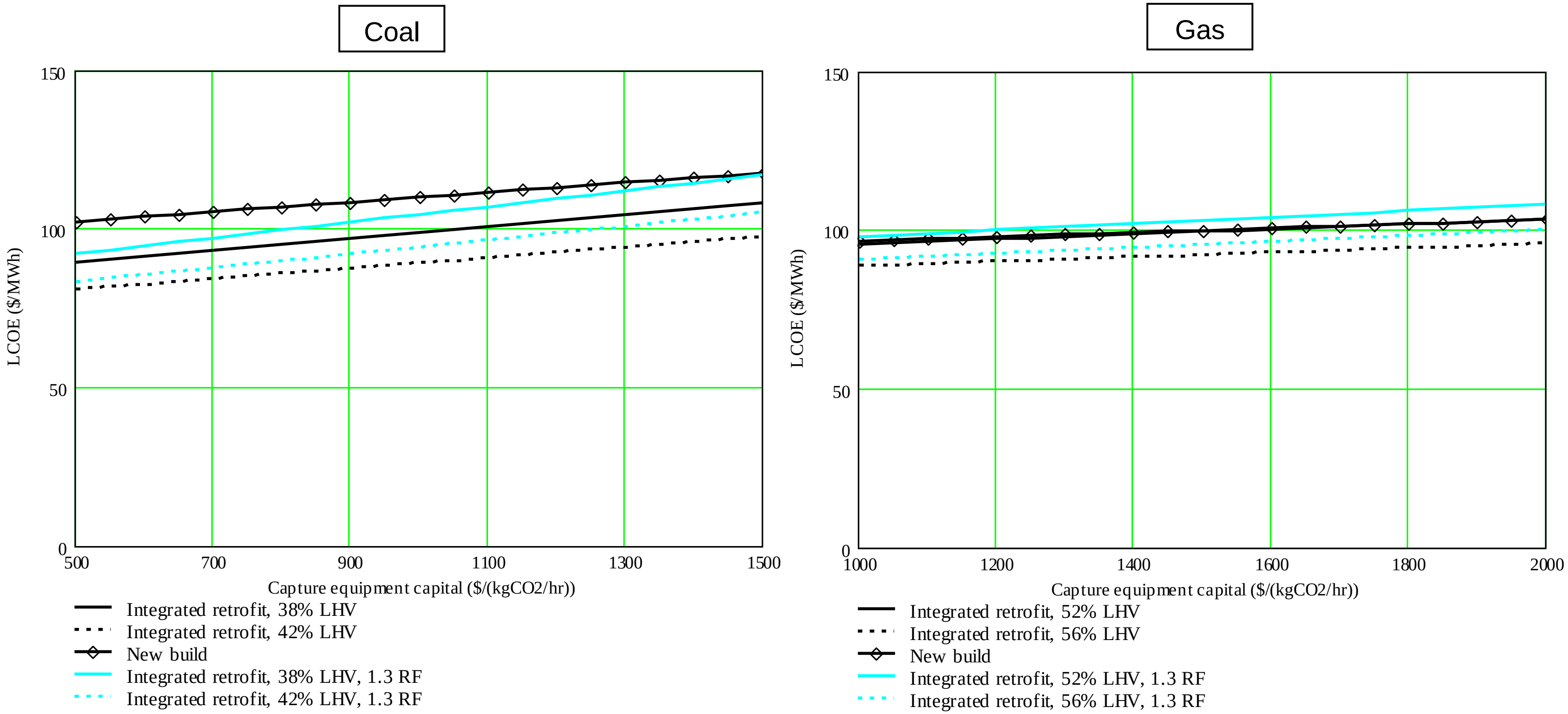
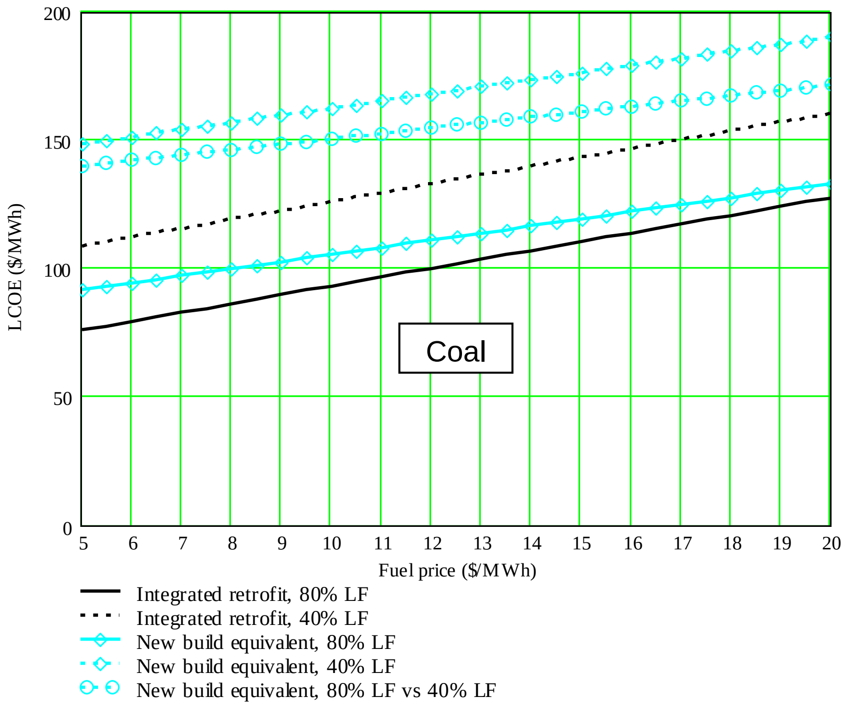
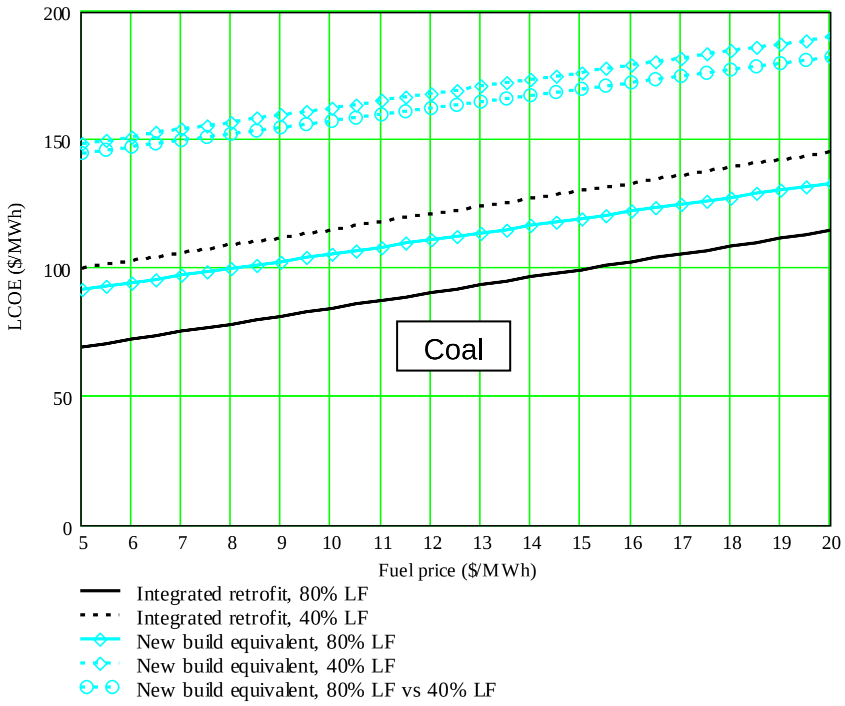


Figure 5.5.5 Effect of variation in capture equipment capital cost for two retrofit plant efficiencies and with retrofit factors of 1 (same cost as new plant, so capture ready) and 1.3 (more difficult retrofit, cost is 1.3 times the value shown for new plant).

As shown in Figure 5.5.5 above, LCOE differences for new build and retrofitted plants are relatively unaffected by changes in the cost level of the capture equipment, since it applies nearly equally to them both. This is especially the case for higher efficiencies (e.g. if the existing plant is already using supercritical steam conditions in the coal case). A 30% increase in the unit cost for retrofitted capital equipment would have slightly more effect, although such an increase would not be expected if the existing plant had been designed to be capture ready for the retrofitted capture technology.



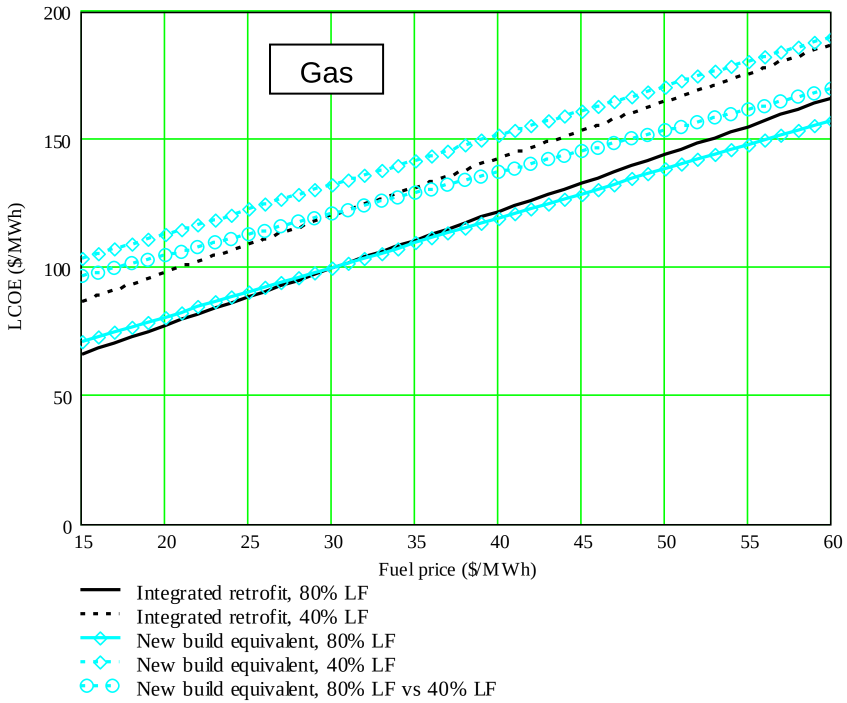
(a) Existing plant efficiency 38% LHV



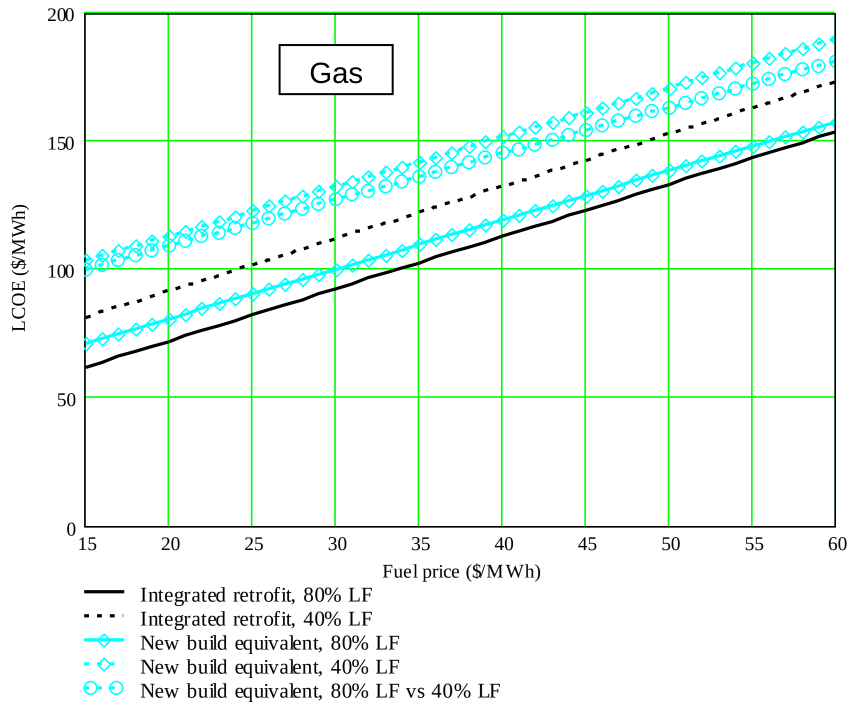
(a) Existing plant efficiency 42% LHV

Figure 5.5.6(a) Effect of coal price on LCOE for new build and integrated retrofit options

As would be expected LCOE values increase monotonically with coal price, but the greater efficiency of the new build plant leads to a slightly lower rate of increase, particularly compared to the retrofit to the 38% efficiency plant. For the default values this is not, however, sufficient to offset the higher capital cost of the new build plants even for the highest coal cost used.



(a) Existing plant efficiency 52% LHV



(a) Existing plant efficiency 56% LHV

Figure 5.5.6(b) Effect of gas price on LCOE for new build and integrated retrofit options

As would be expected LCOE values increase monotonically with gas price, but the greater efficiency of the new build plant leads to a slightly lower rate of increase, particularly compared to the retrofit to the 52% efficiency plant. For the default capital values used this is sufficient to offset the higher capital cost of the new build options at fuel prices above about $35/MWh ($10.3/MBtu or $9.7/GJ).

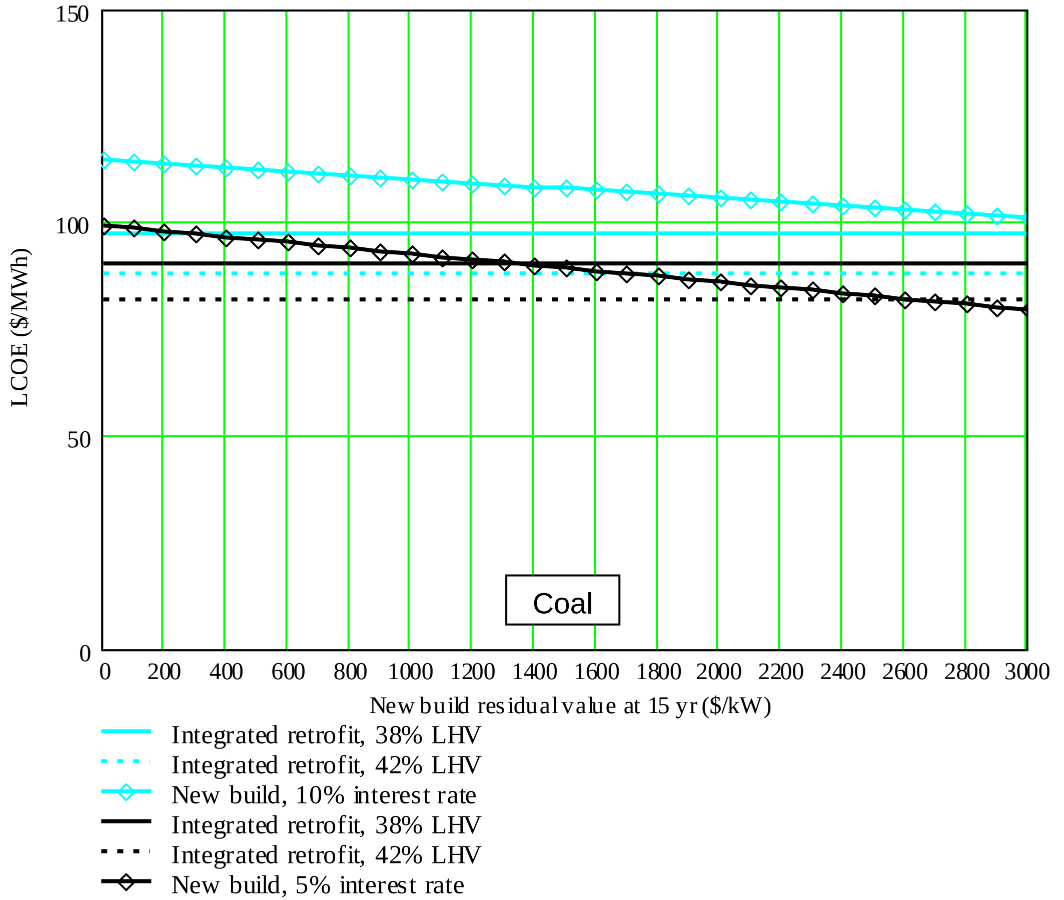


Figure 5.5.7a Effect of capture retrofit life of 15 years, with a longer new build plant life valued as varying residual capital value at 15 years
(blue lines for 10% interest, black lines for 5%)

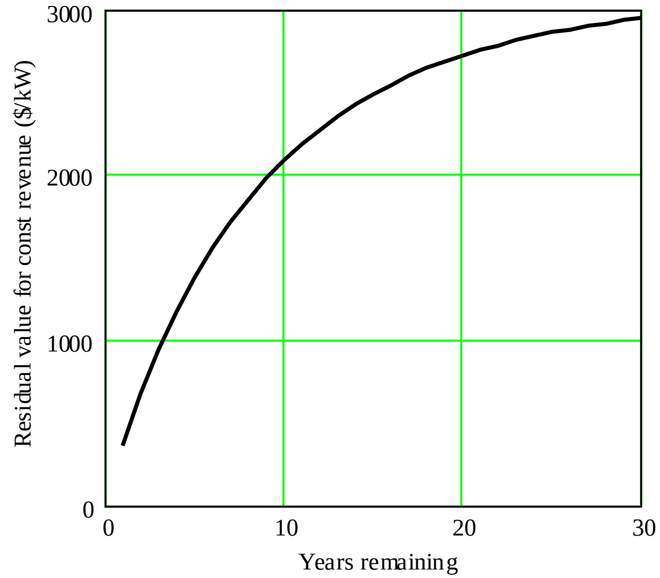


Figure 5.5.8a Residual value for further years of operation under unchanged market conditions for a new build coal plant

If a reduced economic life of 15 years is assumed for the retrofitted existing plant and a new build plant will have a longer life then at the end of the 15 years the latter will have a residual value. This will reduce the effective LCOE for comparison with the retrofitted plant, as shown in Fig. 5.5.7a.

For comparison, the capital value for the new coal capture plant with default input parameters is 3078 $/kW with capture. Fig. 5.5.8a shows how the residual value would vary for a given number of further years of operation beyond 15 years assuming the same revenues and costs were obtained. But obsolescence, or market changes, might reduce future earnings.

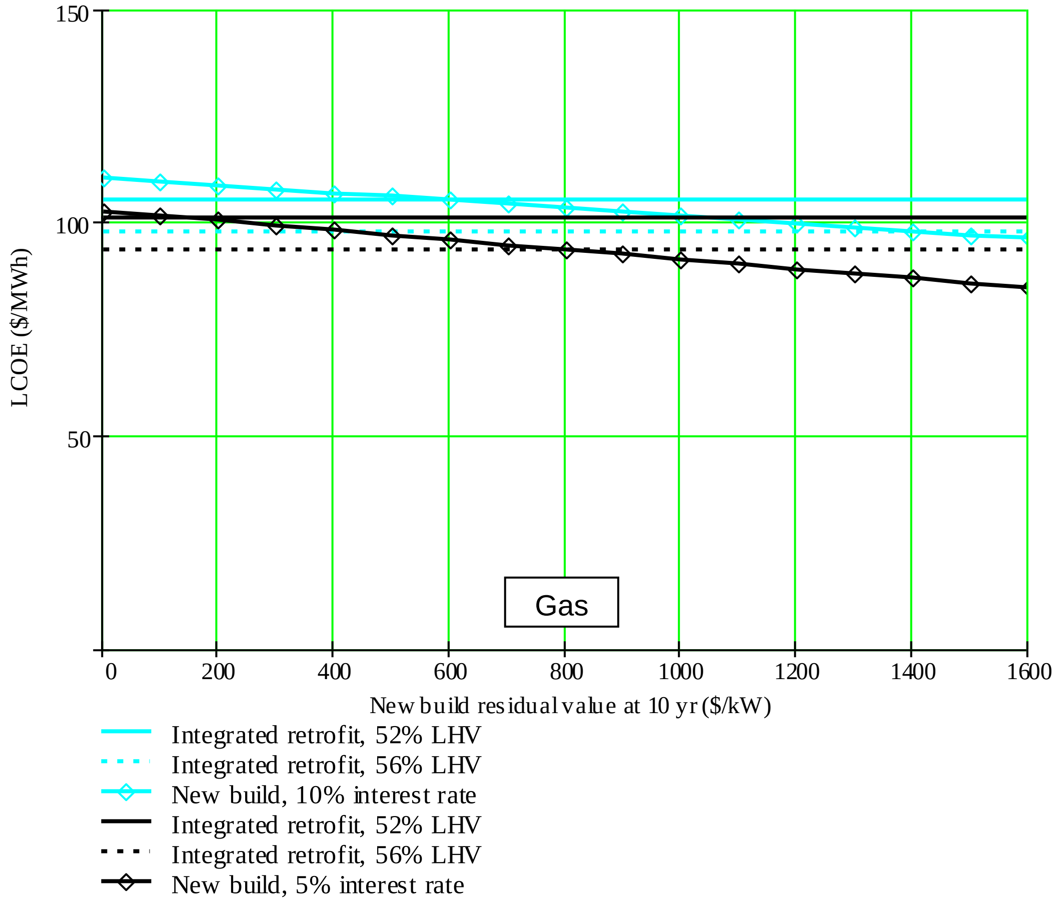


Figure 5.5.7b Effect of capture retrofit life of 10 years, with a longer new build plant life valued as residual capital at the 10 year point.
(blue lines for 10% interest, black lines for 5%)

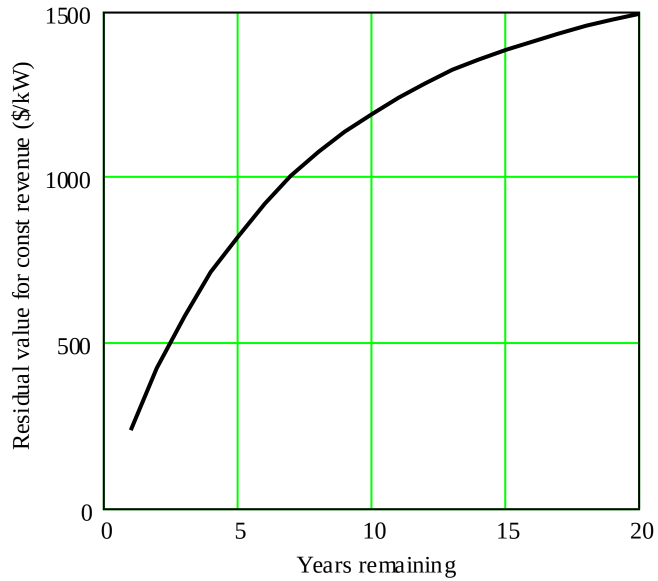


Figure 5.5.8b Residual value for further years of operation under unchanged market conditions for a new build gas plant

If a reduced economic life of 10 years is assumed for the retrofitted existing plant and a new build plant will have a longer life then at the end of the 10 years the latter will have a residual value. This will reduce the effective LCOE for comparison with the retrofitted plant, as shown in Fig. 5.5.7b.

For comparison, the initial capital value for the new natural gas capture plant with default input parameters is 1650 $/kW with capture. Fig. 5.5.8b shows how the residual value would vary for a given number of further years of operation assuming the same revenues and costs were obtained. But obsolescence, or market changes, might reduce future earnings.

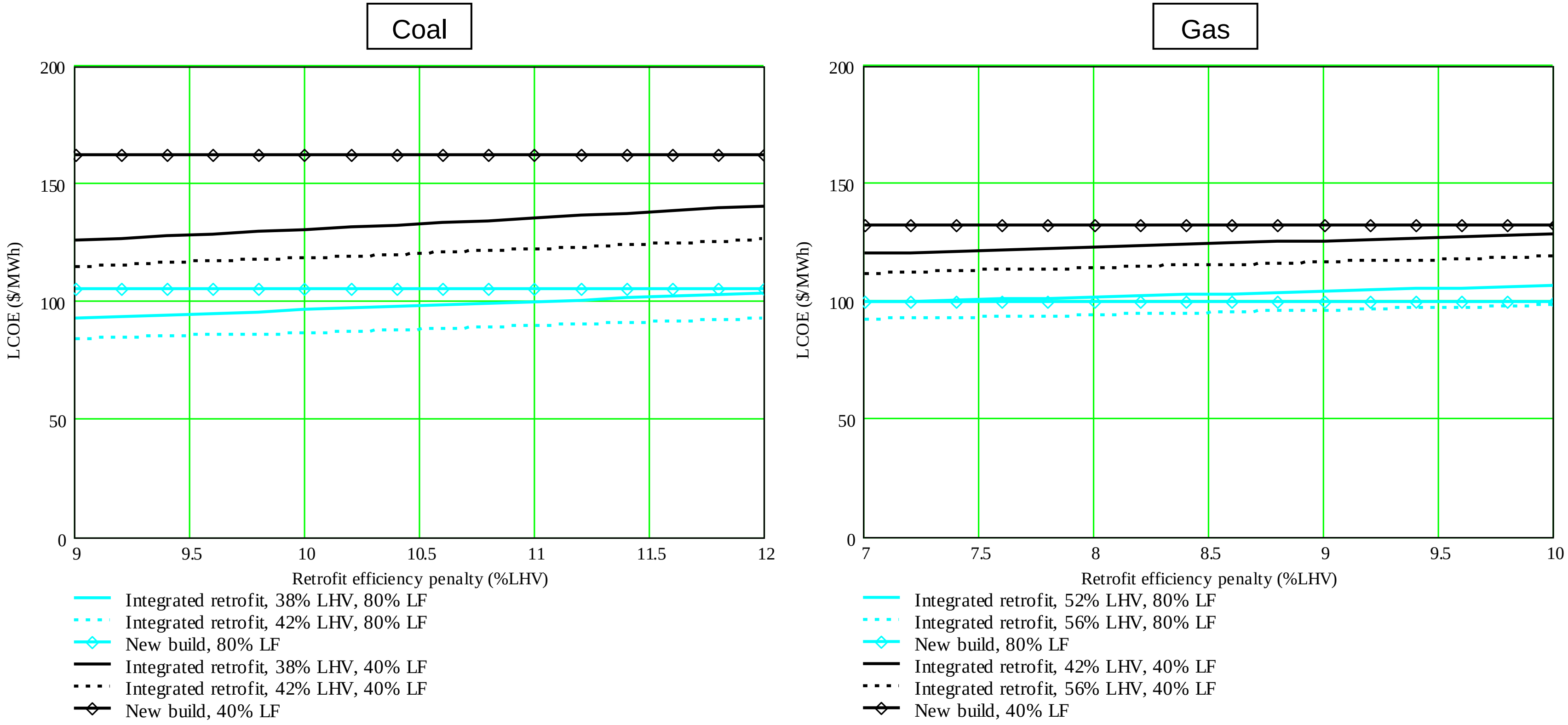


Figure 5.5.9 Effect of higher retrofit capture efficiency penalty on LCOE

As would be expected, higher retrofit efficiency penalties increase retrofit LCOE values, but especially at the lower load factor of 40% likely increases would not make retrofit more expensive than new build for the default data values for coal. For gas, capital costs are lower for new build (and retrofit) so plausible changes in retrofit efficiency penalty could affect investor choice between new build and retrofit if an 80% load factor is expected.

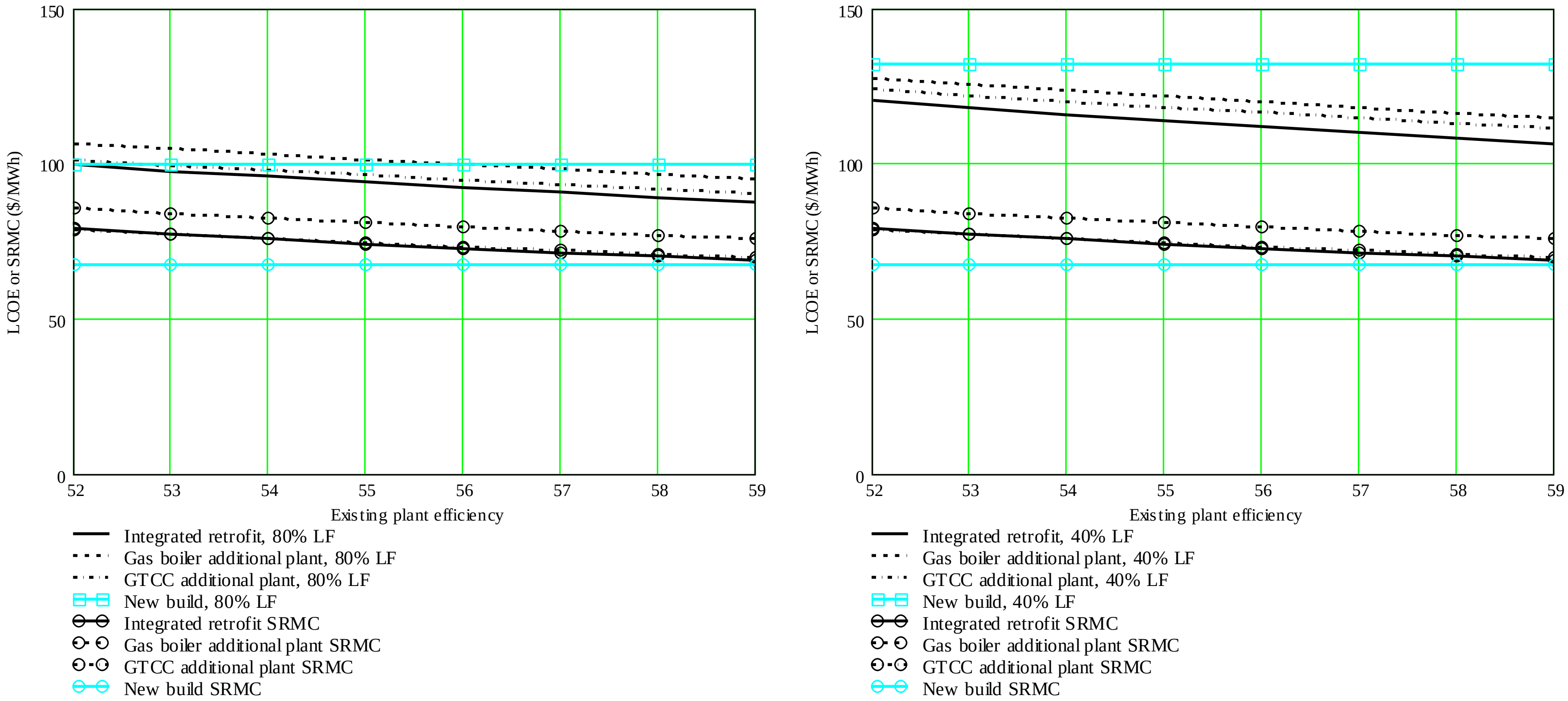


Figure 5.5.10 Natural gas CCGT integrated and additional plant retrofit options showing the effect of existing plant efficiency on LCOE at 80% and 40% load factor

Natural gas plant LCOE values are sensitive to efficiency because of the high fuel cost component. Nonetheless, the sensitivity to efficiency over the likely range is relatively low and would appear to be offset by capital cost differences at reduced (40%) load factors.

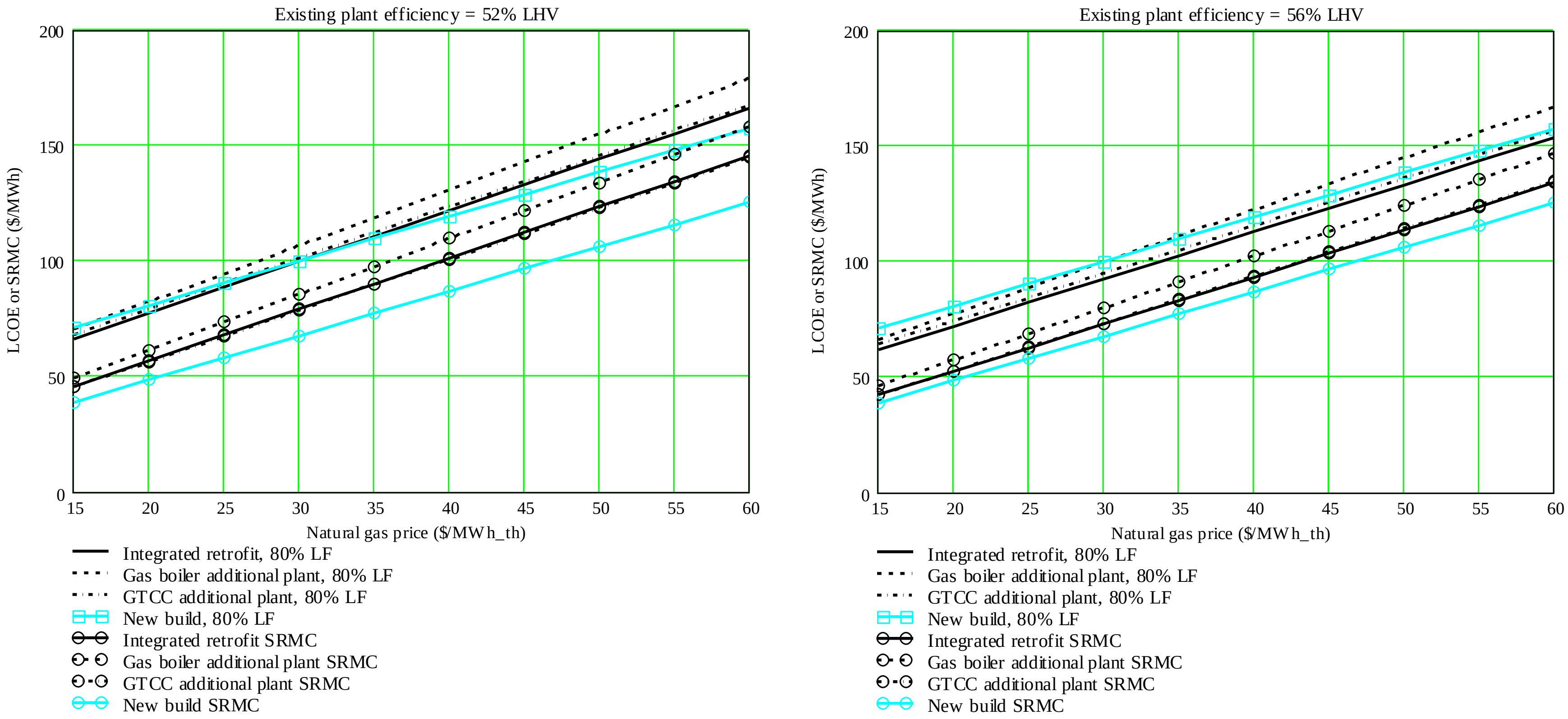


Figure 5.5.11a Effect of natural gas price on electricity costs for retrofit and new build options at 80% load factor

Although LCOE values for all capture options vary significantly with natural gas price the switch-over in estimated cost advantage between new build and retrofit options, due to their differences in efficiency, occurs relatively slowly and in practice would be very dependent on the assumed default data set values.

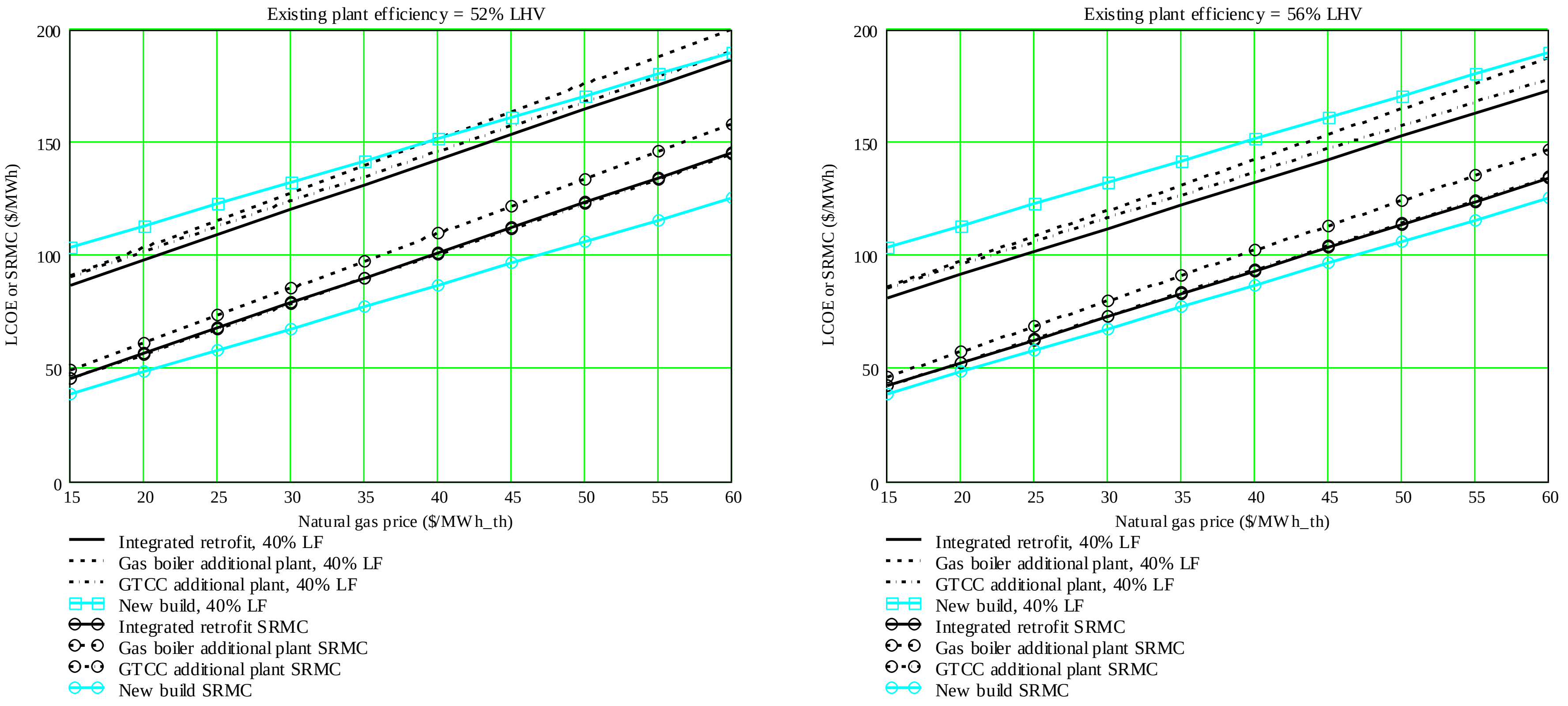


Figure 5.5.11b Effect of natural gas price on electricity costs for retrofit and new build options at 40% load factor

As would be expected, new build LCOE values are elevated at an assumed lower load factor and much higher natural gas prices would be required to make new build competitive with retrofit. This is particularly the case where the retrofitted plant is assumed to have a higher efficiency (56% rather than 52% for the default and sensitivity data values chosen for this analysis).

5.6 Examination of the relative economics of capture retrofit and new build CCS options for PC and NGCC plants - summary of key points

Comparing integrated retrofit options at different sites:

- When comparing integrated retrofit options for a range of existing plants in the same electricity market, and so receiving the same electricity prices, the efficiency of the existing plant will have no intrinsic effect on the cost of CO_2 emissions abatement by retrofitting. Higher costs will apply for fitting capture to a lower-efficiency plant but, provided all other non-efficiency factors are equal, these are entirely offset by higher emission reductions. These other site-specific features, such as ease of retrofit, load factor, size of plant and access to storage, may affect abatement costs for retrofitting though. (As existing plant efficiency decreases, however, the rising cost of generation for the retrofitted plant with CCS makes it more likely that its LCOE will exceed that for a new build plant. In this case the cost of cutting emissions by replacing the existing plant with a new plant with CCS will be lower than cost for a retrofit.)

Comparing retrofit and new build options at the same site:

- While apparent differences in levelised cost of electricity values are small these can have a much larger effect on the nominal cost of CO_2 emissions abatement and the relative return on capital costs for the different options, since these two metrics depend on cost differences not absolute values.

- Integrated capture retrofit options are the most competitive for the default performance and cost data assumed and for most data sensitivity ranges too.

- The next most competitive retrofit option in most cases is a power matched, high efficiency CHP plant (GTCC for gas fuel, high pressure boiler for coal), used in conjunction with an integrated retrofit to restore the power sent out to the original value and to supply some of the additional heat required by the capture process.

- The way in which a power-matched retrofit is implemented may differ. Coal plants, which need to be relatively large to use high steam pressures, may be built to service a number of retrofits on a multi-user site. Since smaller natural gas GTCC CHP units are available these could be used for a retrofit of a single unit.

- If steam extraction from the existing steam cycle is not possible then a high-efficiency CHP plant may be used to provide heat for the existing power plant's and its own capture units, but it may not be possible to export the significant amounts of extra power this will generate from the site. The high level of new plant investment may also not be competitive, despite the reasonably high efficiency that this option is likely to achieve.

- A lower efficiency but lower cost (capital and LCOE, with the default data values assumed) alternative that does not involve steam extraction or excess power production is to use a boiler and back pressure turbine to match both heat and power requirements.

6 Possible global potential for CO_2 capture retrofit vs replacement by new build

6.1 Overview and scope of further analysis

The earliest time that extensive CCS retrofits might take place is likely to be the decade 2020-2030. Significant numbers of retrofits (although also involving extensive refurbishments or rebuilding in some cases) may take place before this for technology demonstration and development (e.g. currently proposed retrofit/refurbish/rebuild CCS projects such as Futuregen 2 (USA), Boundary Dam (Saskatchewan, Canada), Longannet (UK)). It is expected, however, that two generations of development (i.e. first-of-a-kind projects of the order of 100-300MWe, followed by reference projects on full scale power plants up to 800-1000MWe) over the next 10 years may be required before widespread rollout of fully-proven CCS technology would take place (e.g. see Figure 6.1).

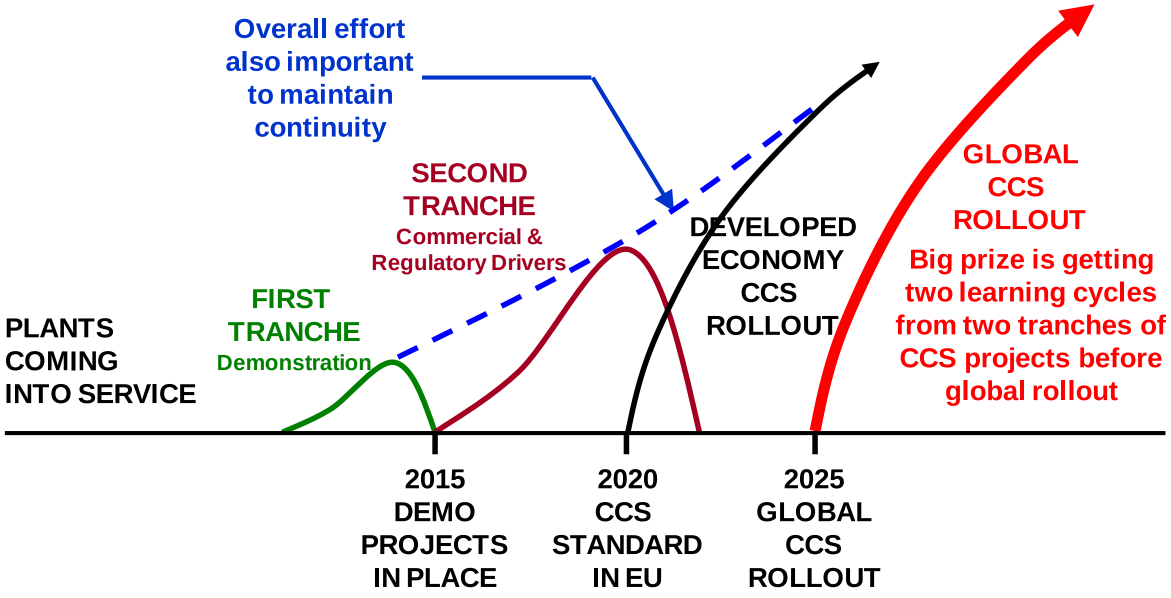


Figure 6.1 Schematic view of a two-tranche model for demonstration and deployment of CCS (Gibbins and Chalmers, 2008)

While retrofits may obviously also happen later than the 2020s uncertainty with respect to changes in power plant fleets, power plant and CCS technology and global and national markets make even qualitative assessments progressively harder over longer periods, as well them being also less relevant for current decision making within the electric utility industry or for energy policy planning.

As with some earlier sections of this report, the key question that needs to be addressed is the potential, should the need arise in the 2020s, for existing fossil power plants to have CCS retrofitted rather being replaced by new build plants with CCS. Whether or not there will in fact be such a driver to curtail CO_2 emissions from the fossil fuel generation sector depends on a range of factors such as international and national targets for greenhouse gas emissions and the technical, economic and social viability of alternative low-carbon electricity generation (or electricity demand reduction) options. Consideration of these is clearly beyond the scope of this study and indeed they involve many additional areas of considerable current uncertainty.

A viable retrofit project will have to satisfy a range of requirements in three separate, although interlinked, areas, shown in Figure 6.2 as the 'retrofit triangle' (by analogy with the well-known 'fire triangle' of fuel, oxygen and heat):

- The ability to add CO_2 capture on the power plant site (or at a linked site in some cases);
- Access to secure CO_2 storage; and
- Economic and social viability, including meeting all legal requirements and gaining public acceptance.

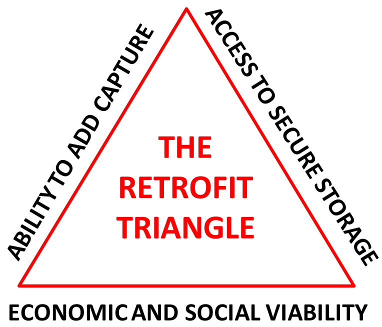


Figure 6.2
The 'Retrofit Triangle'

The first two sets of requirements involve an assessment of the site and its location. The last depends on a number of factors but, for the question of economic viability compared with a replacement new build CCS plant (with both otherwise therefore being assumed to be economically and socially viable) a key limiting factor is the lifetime for the investment in a retrofit project, with a minimum of 10 to15 years and ideally 20 or 25 probably being required.

The question of plant life after retrofit arises in particular for developed economies such as western Europe and USA, which have relatively old fleets of coal fired power plants. It is much less of an issue in the decade 2020-2030 (and subsequently) for developing economies such as China where large numbers of new fossil power plants have been built recently and are expected to continue to be built. It would be helpful if these plants were built capture ready to ensure retrofittability at minimum cost, but it is likely that in any circumstance a significant number of plants with sufficient lifetimes will exist and, as will be examined in Section 6.3, the limiting factors are then suitability for installing capture equipment and access to storage.

For developed economies, with many relatively old fossil power plants and some new plants alternative possibilities for changes to the existing fleet between now and the 2020s, when CCS rollout might start, include:

A) Build no or few new fossil power plants – but then CO_2 emissions don't go down except through demand reduction or construction of non-fossil generation capacity that displaces existing fossil plant. This scenario may therefore involve tension with climate objectives. In some markets, it is typically expected that new fossil power plants will be required anyway to meet additional demand or to replace existing plants that are forced to close by changes in environmental emission legislation.

B) Build some new fossil power plants – in order to make some reductions in fossil generation emissions and/or meet otherwise unsatisfied electricity demand, with options:

i) Build new coal plants and reduce emissions by other means, including replacing low-efficiency coal plants with high-efficiency. In some jurisdictions (e.g. the UK) new coal power plants would have to fit at least some CCS from the outset, and this might also be a *de facto* requirement in other situations to gain sufficient public acceptance. Many new coal plants are also likely to be capture ready for any part of their capacity not fitted with CCS, either as a regulatory requirement or as a means for the project developer to limit future exposure to increased carbon prices or more severe emission regulations.

ii) Replace coal with natural gas in the generation mix, by building new gas plants and closing coal plants and/or operating coal capacity at reduced load; it appears that the UK is currently an example of this approach, with the USA possibly following. It is not expected that new natural gas plants will have CCS fitted from the outset but in at least some markets (e.g. the UK) they would be required to be capture ready.

Under option A the prospect for retrofits probably decreases as the whole plant fleet gets older. Under option B(i) the prospects for retrofits on coal could:

- not decrease as rapidly as might be expected, assuming that older coal plants are replaced first by coal plants with CCS so that the average age of the existing fleet increases less quickly than might be expected;
- increase if a significant part of any new coal capacity is built without CCS; or
- decrease, if new coal capacity with CCS fills the available market niches.

Under option B(ii) the prospects for retrofit on coal probably also decline less quickly than might be expected if older coal plants are replaced first by gas. The prospects for retrofit of relatively new natural gas plants will then obviously rise, especially if the market conditions that made new gas construction more attractive than coal persist. For that large part of the coal fleets in developed economies which has been commissioned in the 1970s, plant lives of 60 years or longer would be required to achieve post-retrofit lifetimes of 15-25 years. This implies that a major refurbishment would be required at the time of retrofit in many cases, with the costs for this also reflecting the extent to which previous ongoing maintenance and upgrading had been undertaken (including possibly modifications to improve their capture readiness as opportunities arise from other interim maintenance or refurbishment activities). The economic attractiveness of this option would also be affected by the expected load factor of either retrofitted or new build plants. For example, if fossil plants experience lower load factors due to increased variable renewable penetration then this would favour coal retrofit projects with lower capital costs over new build coal CCS plants, but perhaps also favour natural gas CCS plants if these had acceptable fuel costs and even lower capital costs.

While noting this requirement also to assess the suitability of a plant for refurbishment and life extension, it will not receive further attention since it has not been addressed to any significant extent in the recent studies of retrofit potential summarised in the rest of this section, which have concentrated on site and location issues. Interested readers can refer to previous work in this area such as Ambrosini (2005). This is probably only a serious concern, however, for the first study (Section 6.2) which looks at the USA coal fleet. The second (Section 6.3) examines the much younger Chinese coal fleet and the third study (Section 6.4) covers the predicted 2030 UK gas fleet (much of which will be CCR, given this is now a requirement for consenting new fossil plants in the UK).

6.2 Retrofit potential in the USA

A comprehensive GIS-based survey of existing coal fired plants in the USA has recently been undertaken to assess their retrofit potential (NETL, 2010). Although the screening criteria used (>100MW, >27.3% thermal efficiency HHV and <40km to storage) in order to identify a subset of plants to study in more appear to be somewhat arbitrary they do still include a large proportion (85%) of the reported operating capacity of 331GW, as shown in Figure 6.3.

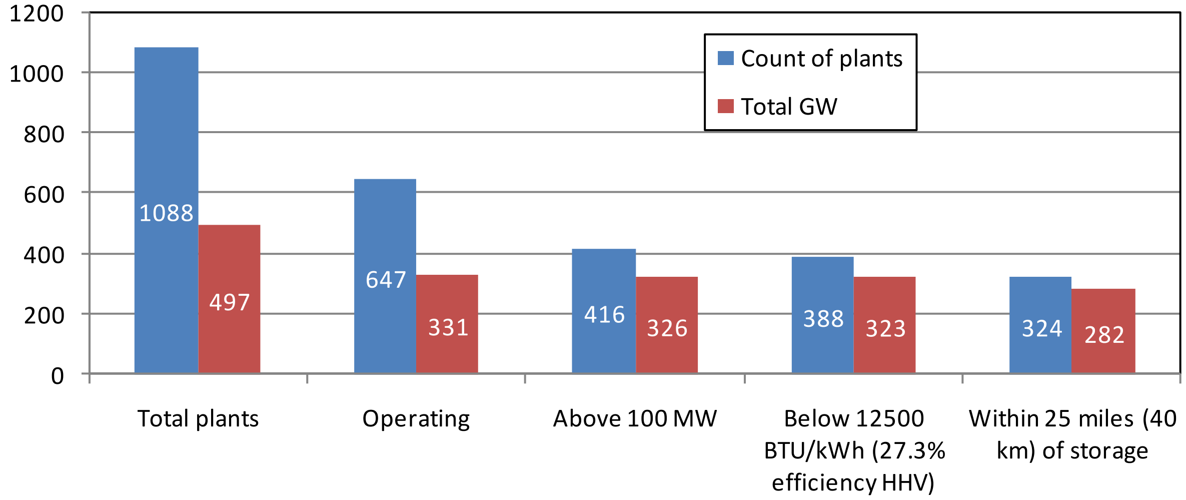


Figure 6.3 Effect of screening criteria in NETL 2010 retrofit study on the number of plants and coal generation capacity subsequently examined in detail

Additionally, it is worth noting that Figure 6.4 shows that of the 388 coal plants that pass the other screening tests used in this study a reported total capacity of 320 GW, representing 97% of operating capacity meeting these other screening tests, are within 100 miles (160 km) of geological storage. While the feasibility of installing a suitable pipeline and the actual length of the pipeline routes are not assessed it appears that both transport and storage (see Figure 6.5) requirements for retrofits at a significant number of sites have a good chance of being met.

The feasibility of adding capture at power plant sites was assessed using aerial and satellite images of power plant sites from Microsoft TerraServer-USA and Google Maps, based on retrofit design data from NETL's Conesville retrofit study (Ramezan, 2007). Amine post-combustion capture was assumed for all retrofits, with steam supplied entirely from the main steam cycle. Thus the scope for using the different characteristics of other retrofit options, including oxyfuel, to overcome site-specific problems was not considered.

No sites were considered totally infeasible for retrofit but it was assumed that up to nearly double additional capital costs could be incurred if, based on assessments of plant images, equipment had to be added in close proximity to other plant and also if overall space on site was limited. Reflecting this, and other site specific factors, estimated electricity generation costs after retrofit spanned a wide range, from $40/MWh to $150/MWh (Figure 6.6).

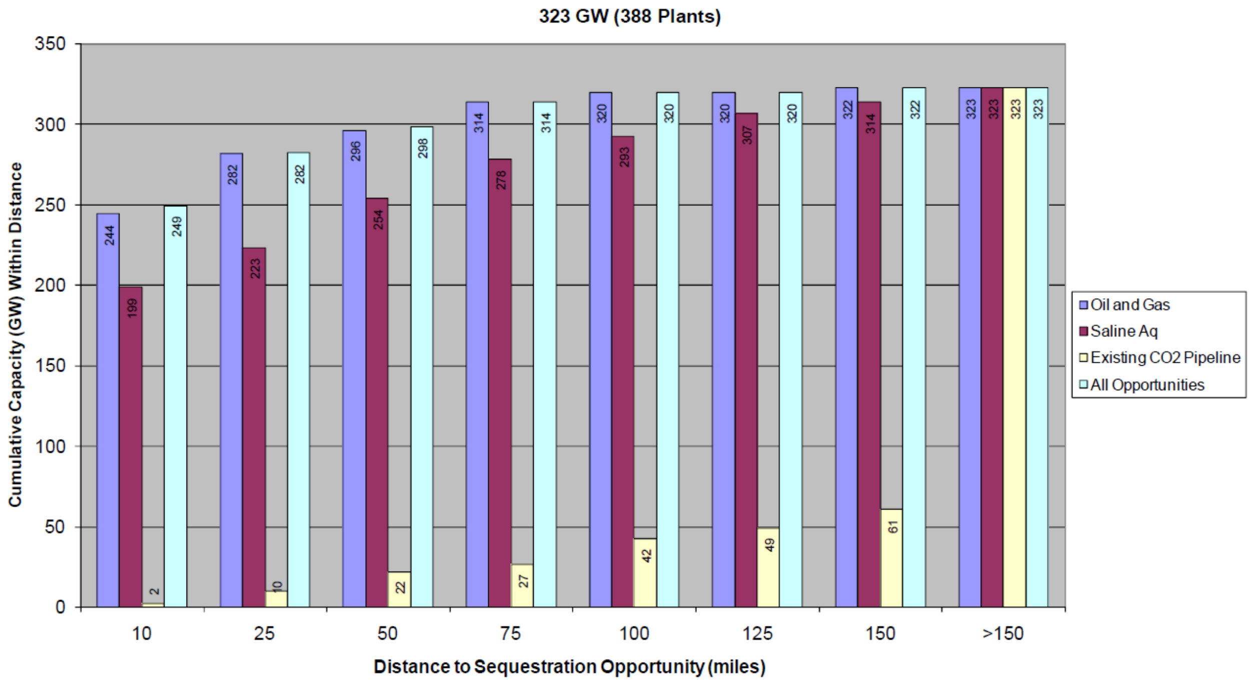


Figure 6.4 Distance to prospective storage locations for operating US coal plants
(100 miles = 160 km)

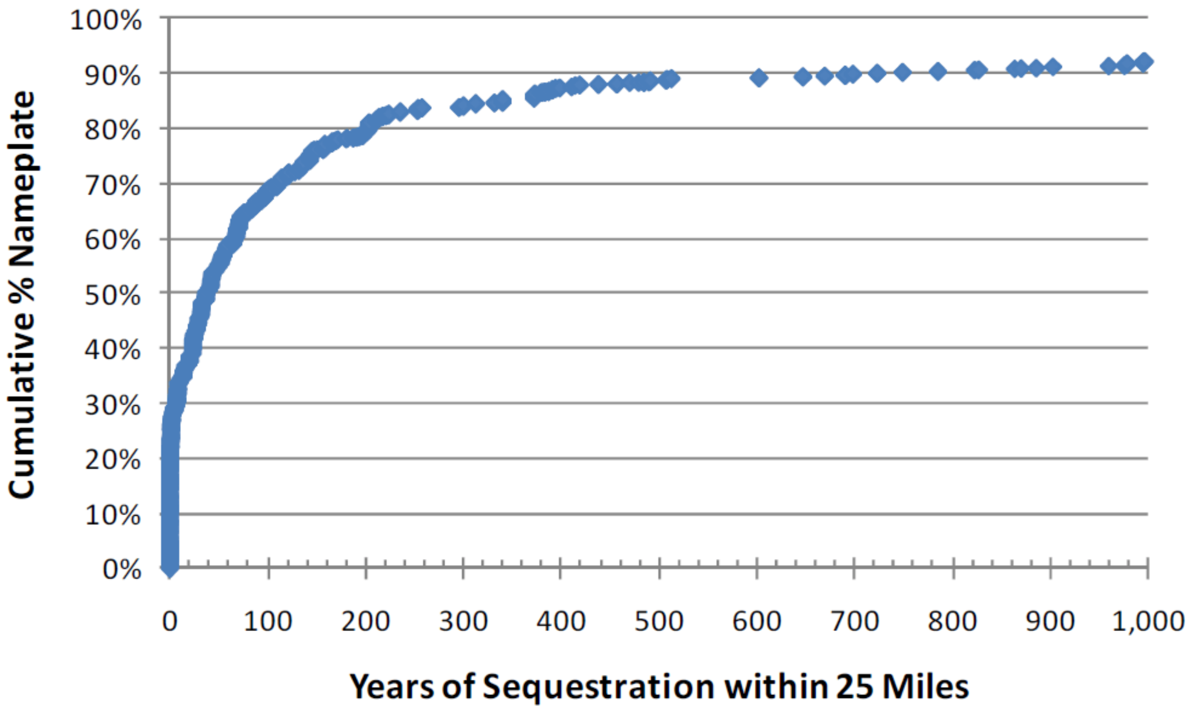


Figure 6.5 Estimated storage capacity (based on NETL NatCarb data – www.natcarb.org) for 282 GW (738 units) at operating US coal plants

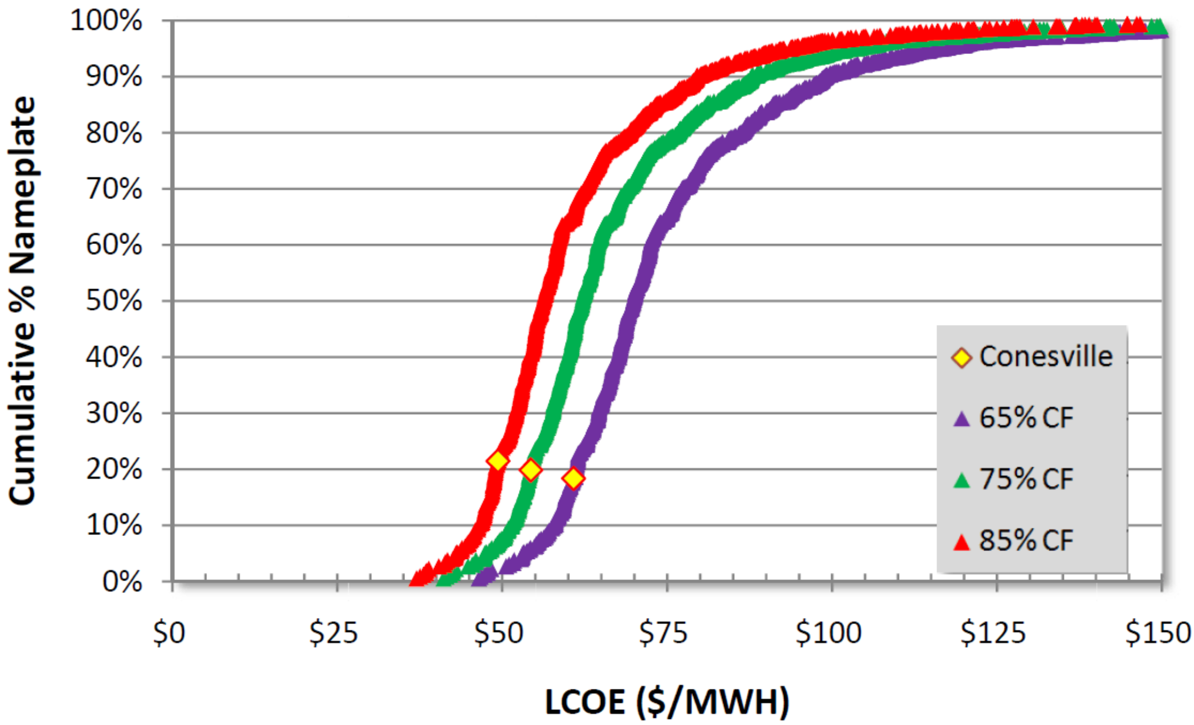


Figure 6.6 Estimated levelised cost of electricity generation for selected operating US coal plants with 90% CO_2 capture operating a annual capacity factors of 65%, 75% and 85% with no cost for make-up power and no CO_2 emission costs.

No possible dates for retrofits were considered, although an economic life for retrofits of 20 years was assumed and the effect of making up 'lost' power and possibly getting credits for CO_2 captured based on projections for 2020 was also examined. As discussed earlier, the dates on which US plant retrofits might take place is of interest because of the average age of the US coal fleet, with most of the larger units first operating in the mid to late 1970s and smaller units on average in the mid 1960s – see Table 6.1. This raises the question of the age of the units when retrofits might take place at some stage in the future and whether or not it would be technically and economically feasible at that point to operate them for an additional 20 years as assumed.

Table 6.1 US coal fleet statistics operating units from EIA 2008 data
EIA, Electricity Generating Capacity, Spreadsheet 'Existing Electric Generating Units in the United States, 2008 (by Energy Source)', http://www.eia.doe.gov/cneaf/electricity/page/capacity/capacity.html

Operating US coal units in 2008, total capacity 334.3 GW, ordered by unit size										
Capacity centile	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
No. of units	689	190	125	85	64	58	52	47	41	32
Ave. nameplate capacity (MW)	48	175	267	394	518	582	638	708	820	1053
Ave. year of operation	1965	1962	1967	1974	1978	1977	1975	1979	1977	1977

Options to 'refurbish' plants at the time of retrofit were also considered but, since it was assumed that all plants down to 50MW could effectively be converted to supercritical steam conditions (likely to be technically infeasible at smaller sizes) and at a constant capital cost equivalent to $67/t$CO_2$ avoided, these results have to be regarded as very preliminary. Empirical observations in the UK (e.g. Tilbury, Kingsnorth proposals for 800MW supercritical units) suggest that utilities would prefer to replace existing older coal units with completely new supercritical units if a supercritical coal generation capability was to be retained on the site. In Canada a post-combustion capture retrofit proposed for a 150MW unit at Boundary Dam, Saskatchewan would involve plant refurbishment and improvements in steam turbine technology with useful gains in station efficiency and an estimated 30 years' life extension (for a unit built in the early 1970s), but not the equivalent of conversion to supercritical operation (Sundarjan, 2010). But these are a very limited number of examples and it may be that the comprehensive boiler replacement and turbine modification that would allow supercritical operation, as described in Panesar (2009), would prove attractive for units of sufficient size (likely to be >400MW) which still have adequate life in the remaining equipment on site.

A more detailed analysis of retrofit and replacement option costs for US power plants was presented by Simbeck (2009) as part of an MIT symposium on the topic (MIT, 2009), as summarised in Table 6.2. Simbeck described a refurbishment option for sub-critical plant with steam temperatures being increased from 1000ºF (538ºC) to 1100ºF (593ºC) and a turbine rebuild to improve efficiency, and also replacement by new supercritical steam plant. Additionally, Simbeck's analysis includes replacement of the existing coal plant by natural gas CCGT plant with CCS, although not supplementary use of natural gas in the retrofit. For the assumed parameters (including no need to replace 'lost' electricity and an adequate retrofit life) retrofit options gave the lowest costs for low-carbon electricity, followed by a replacement natural gas combined cycle plant with post-combustion capture. While not conclusive, Simbeck's results (which generally show similar trends to the present study) suggest that retrofit options could potentially be economically viable in the USA compared to new build coal with CCS, even if refurbishing for life extension was required, although alternative natural gas options may also exist depending on prevailing gas prices.

Table 6.2 Summary of options for CO_2 emission reductions from an existing coal power plant (Simbeck, 2009)

Natural gas price ($7.65/MBtu HHV) set so the same power costs are calculated for replacement NGCC or PC, both without CCS and no CO_2 tax.

Case Number	CO2 Mitigation Options - all built at old PC site	Net MWe	New Capital mid-2008 Millions	New Capital constant $ $/kWe	Net Efficiency % HHV	CO2 Emissions mt/MWhe	CO2 Avoidance $/mt CO2	Power Cost mid-2008 $/MWh
O-PC	**Baseline Paid-off Old Coal Plant - no CCS** sub PC with FGD size set to NGCC MW	543	Paid off	Paid off	33.6%	0.95	Baseline	$ 36.8
O-PC-C1	**Old PC & ST with new Post CCS add-on** new small BT ST + MHI amine CO2 scrubber	398	$ 528	$ 1,325	24.7%	0.13	$ 74	$ 97.9
O-PC-C2	**Old PC + upgrade & new Post CCS add-on** rebuild SH/RH + sub ST/gen & MHI amine scrubber	418	$ 755	$ 1,807	25.9%	0.12	$ 79	$ 102.4
NGCC	**Replacement NGCC - no CCS** "F" class NGCC with SCR no CO2 Capture	543	$ 540	$ 993	50.7%	0.36	$ 67	$ 76.2
NGCC-C	**Replacement NGCC with Post CO2 Capture** "F' class GT with MHI amine CO2 scrubber	463	$ 836	$ 1,805	43.3%	0.06	$ 83	$ 110.7
N-PC	**Rebuild SC-PC Power Plant - no CCS** Supercritical PC + FGD & SCR - not CO2 Capture	630	$ 1,354	$ 2,151	39.0%	0.82	$ 302	$ 76.2
N-PC-C	**Rebuild SC-PC with Post CO2 Capture** Supercritical PC with MHI amine CO2 Scrubber	499	$ 1,765	$ 3,537	30.9%	0.10	$ 111	$ 130.8
N-OPC-C	**Rebuild SC-PC with Oxyfuel CO2 Capture** Supercritical PC with oxygen & flue gas recycle	485	$ 1,644	$ 3,389	30.1%	0.07	$ 104	$ 128.0
IGCC-C	**Repower H2-IGCC Pre-comb CO2 Capture** HP GE Gasifier with quench, CO shift & H2/N2-fired GE 7FB GT	517	$ 1,667	$ 3,224	32.0%	0.08	$ 94	$ 119.5

Does not account for power replacement of net drop from the original 543 MWe plus shorter remaining life of the old PC

Overall, studies on US retrofit potential to date thus suggest that very significant potential for CCS retrofit, as opposed to CCS new build, may exist at present. Since the timing for retrofitting is uncertain, there is also considerable uncertainty with respect to the amount and nature of retrofits that may eventually take place on the now-existing coal fleet (any new coal and gas plants would present more certain prospects for retrofit). Areas of uncertainty for the now-existing coal fleet include:

- Most aspects of economic and social viability, including meeting legal requirements and gaining public acceptance.
- The role of natural gas e.g. will it be implemented without CCS (but perhaps capture ready) as a replacement for coal and present a retrofit opportunity in turn; will it be incorporated in coal retrofits; will it eventually be implemented with CCS as a direct alternative to retrofitting existing coal units?
- Residual existing coal plant life at the time of retrofit and the balance between refurbishment and replacement costs and risks.
- The future development of capture technology and the extent to which it allows site-specific problems to be addressed effectively.

6.3 Retrofit potential in China

CCS retrofit potential in China has received less attention than in the USA, and in particular a comprehensive assessment of CO_2 storage potential is still required. The existing coal fleet in China is also expanding rapidly, including plants built in new locations. While this introduces some uncertainties it also means that significant numbers of relatively modern existing coal plants will potentially be available to retrofit. At present, however, it appears that new power plants in China are not being built capture ready, which, if it were the case, would obviously give much greater confidence in the retrofit potential of these new plants.

6.3.1 Costs for applying CO_2 capture to coal power plants

Costs for CCS on coal plants in China were estimated as part of the Near Zero Emission Coal (NZEC) project (www.nzec.info), as summarised in Figure 6.7 on the next page. The results for existing 300MW and 600MW sub-critical plants shown here are based on meeting the full construction cost of the base plant and it is also assumed that slightly less efficient integration is achieved with the main plant than for new build. Thus abatements costs are slightly higher, implying (as would be expected) that it would be preferable first to fit CCS to new plants that were to be built anyway (and probably also to any capture ready existing plants). But cost of electricity and abatement costs are only slightly higher for the retrofit cases, confirming that retrofit (where it can be achieved with these characteristics) is likely to be preferable to early closure and new build on the same site.

6.3.2 Existing Chinese coal fleet

This section is based on Li (2010), which includes further discussion of some of the strengths and weaknesses of the methods used in the analysis presented here.

a) Power plant data selection and sourcing

Based on official information from the China Electricity Council (CEC, 2007) the number of coal fired power plants with an installed capacity of over 1GW reached 164 sites in the year 2006. These have a total capacity of 233 GW, which amounts to 82% of the total installed capacity of coal fired power plants in China in 2006. The analysis in this section is based on information for these plants. Out of 164, 134 plants could be identified when the address of the power plant was supplied to Google Map. Among these 134 sites, for 74 sites the layouts were clearly shown by Google Earth or Google Map (shortened to Google in the rest of this text); for 54 sites there was no clear plant layout image in Google; for the remaining 6 sites no power plants were in existence at the time of the Google survey. These 74 sites have a total installed capacity of 107.7GW.

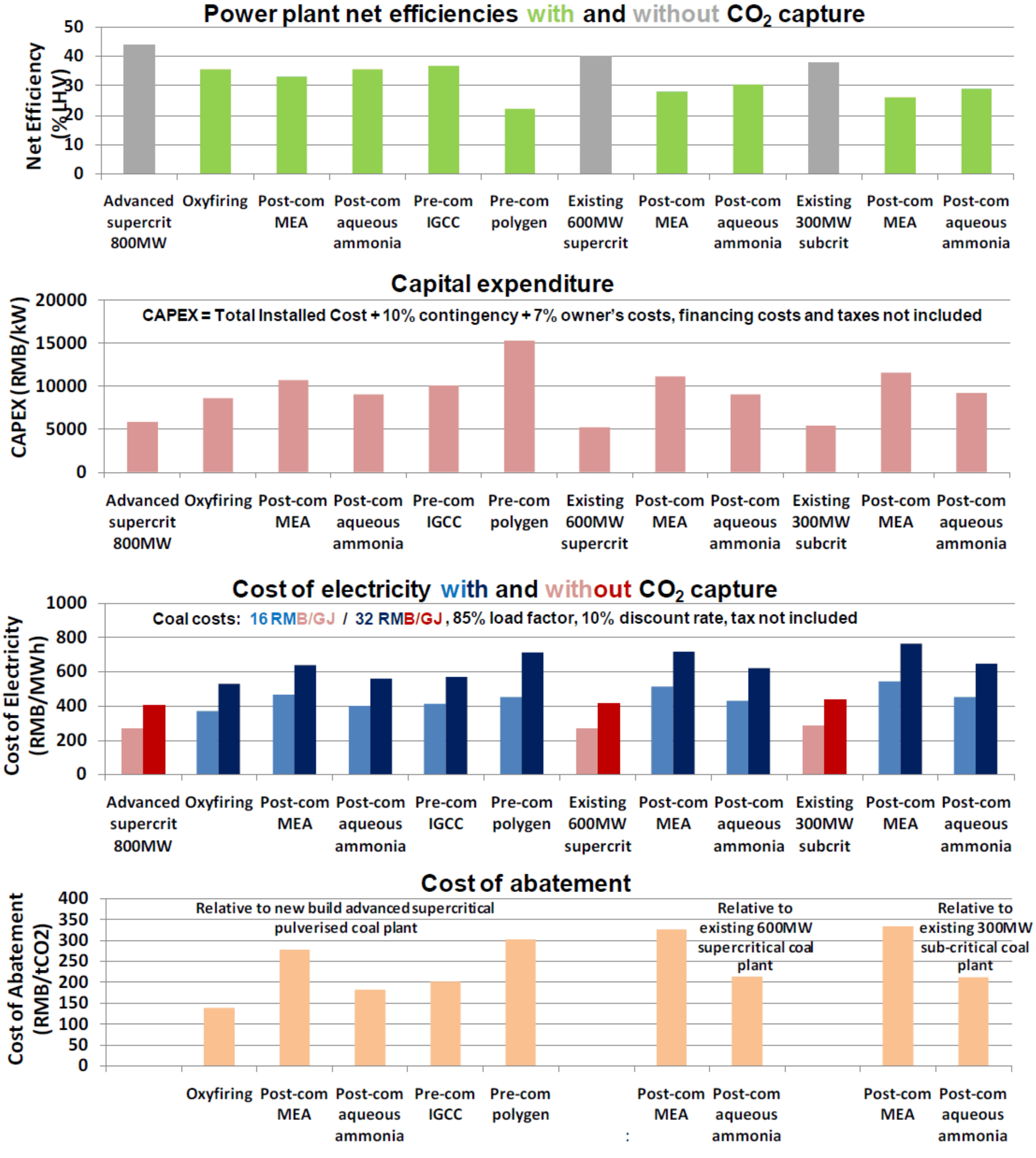


Figure 6.7 Performance and costs for CO_2 capture options for coal plants in China
($1 is approximately 7 RMB)

b) Data analysis

Two major categories and three sub categories are used to classify the layout of the plants. All the plants are classified first by the surrounding area condition, either located in a rural area or in an industrially developed area (shortened to developed area in the rest of this text). This is used to identify the potential to expand the power plant, in order to accommodate additional capture equipment, compression equipment and temporary storage of equipment if necessary. There may be plants that have enough space surrounding them, but where soil conditions are not suitable for construction. However, this is not examined in this study, as this is likely to be a very rare example of why a plant would not be suitable for capture retrofit.

The sub categories are defined by the observable water supply/cooling system. Three main water supply/cooling systems are used: sea water, river water and no obvious direct water supply (cannot be seen easily from Google Earth), which means the plant normally uses wet cooling towers at the time of the investigation. The results of the initial analysis are shown in Table 6.2. Around 62% of the power plants that can be identified clearly in Google images are within industry zones. The percentage of coastal power plants in both cases is very similar, in the range of 14 – 15%. The biggest difference is that the percentage of power plants built next to rivers or lakes is significantly lower in the rural areas than in industrial zones. Power plants with no obvious direct water supply in the rural area are over 60%. A possible reason, as discussed elsewhere in the study, could be that plants built earlier have occupied the prime locations for building power plants (and these prime sites will typically have good access to seawater or river cooling).

Table 6.2 Power plant analysis

Type of Plant		No.	% within main category	%
Rural Area	Coastal	4	14	38
	River	6	21	
	No obvious water supply	18	65	
Within Industry Zones	Coastal	7	15	62
	River	24	52	
	No obvious water supply	15	33	
Total no. of Google Earth images		74		

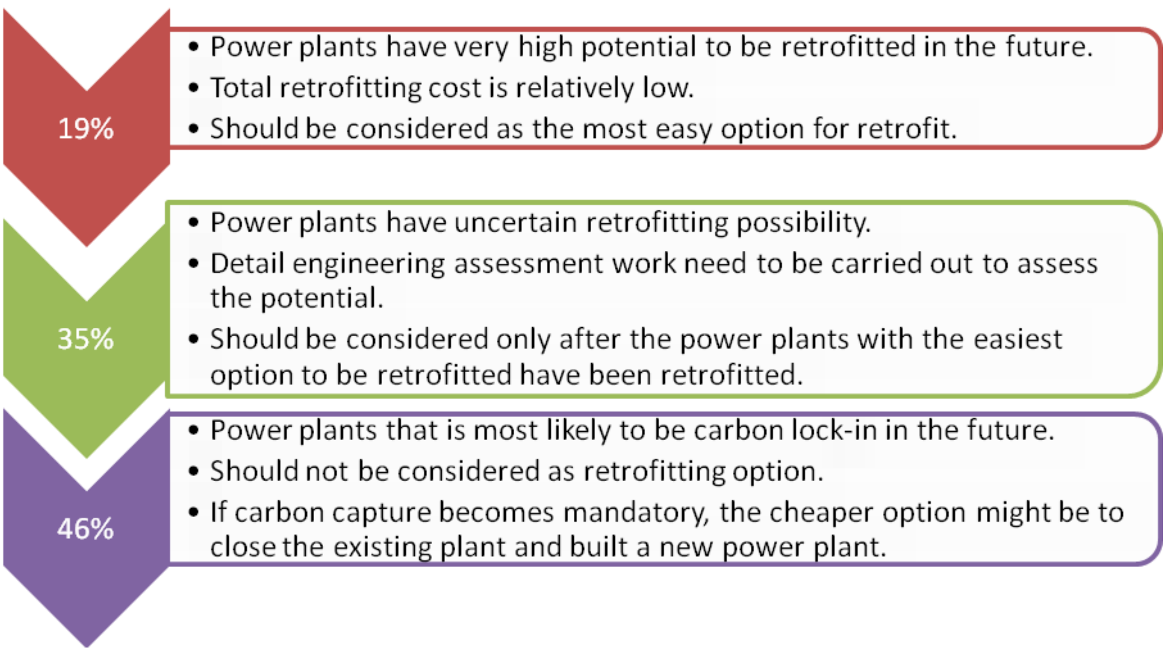


Figure 6.8 Retrofitting possibility

c) Retrofitting possibility

For the power plants that have been examined three types of retrofitting potential have been summarised in Figure 6.8. Only 19% (by number of sites) of the power plants analysed in this study appear to have a high retrofitting potential. The power plants that appear to be at risk of carbon lock-in because of space limitations account for 46% (34 out of the 74 plants with images that could be assessed). Although some of them might still have the possibility to be retrofitted, it is possible that the costs will be significantly elevated. Given the fuel saving for an advanced new boiler, it might be cheaper to build a new plant at a more appropriate site.

The percentages shown in the Figure are calculated by sites rather than installed capacity. Because the older sites tend to have more smaller size units, the percentage of power plants that are not suitable for retrofit in terms of total installed capacity will be somewhat less than 46%. Also, for power plants that have an uncertain scope for retrofitting further investigation is required; because of this limitation of the present study the current retrofitting potential might be higher than estimated.

d) Current capture retrofit projects in China

Three coal fired power plant CO_2 capture retrofit projects had finished construction in China by the end of 2009 (see Table 6.3). As of early 2010, one plant had been fully operational since mid 2008 and the other two were in the test phase. The Gaobeidian (Figure 6.9) project in Beijing had captured over 3,500 tonnes of CO_2 since the capture unit started operation in mid 2008, although the total amount of CO_2 captured is less than 0.5% of that in the power plant flue gas. The capture unit is to the west of the cooling tower, which is highlighted in red in Figure 6.9. Carbon dioxide is purified to over 99% at this stage before it is sent to the next purification stage, which is highlighted in green, for further purification to give food grade CO_2. The absorber and desorber of the primary capture unit are both roughly 1 metre in diameter and 4 metres in height. The food grade capture unit is smaller in size but the equipment is manufactured to a higher standard.

Table 6.3 Capture retrofit projects in China

Project Name	Location	Capture capacity (t/y)	Solvent	Started operation	Plant owner
Gaobeidian	Beijing	3,000	MEA	Mid 2008	Huaneng
Shuanghuai	Chongqing	10,000	MEA	Jan 2010	Zhongdiantou
Shidongkou	Shanghai	100,000	MEA	Dec 2009	Huaneng

Because the Shanghai plant is relatively new compared with the Beijing plant, the capture unit and the power plant had not finished construction when the Google image was taken. Figure 6.10 shows the location of the 100,000t/y primary capture unit (in red) and the secondary food grade capture unit (in green) at Shidongkou power plant. The total size is roughly half of a football (soccer) ground. The flue gas handling capacity is equal to 4% of the 660MW boiler flue gas. If more carbon dioxide needs to be captured in the future, it appears likely that space restrictions could mean that it will be difficult to retrofit high levels of CO_2 capture all the units (currently 2x600MW plus 2x660MW).

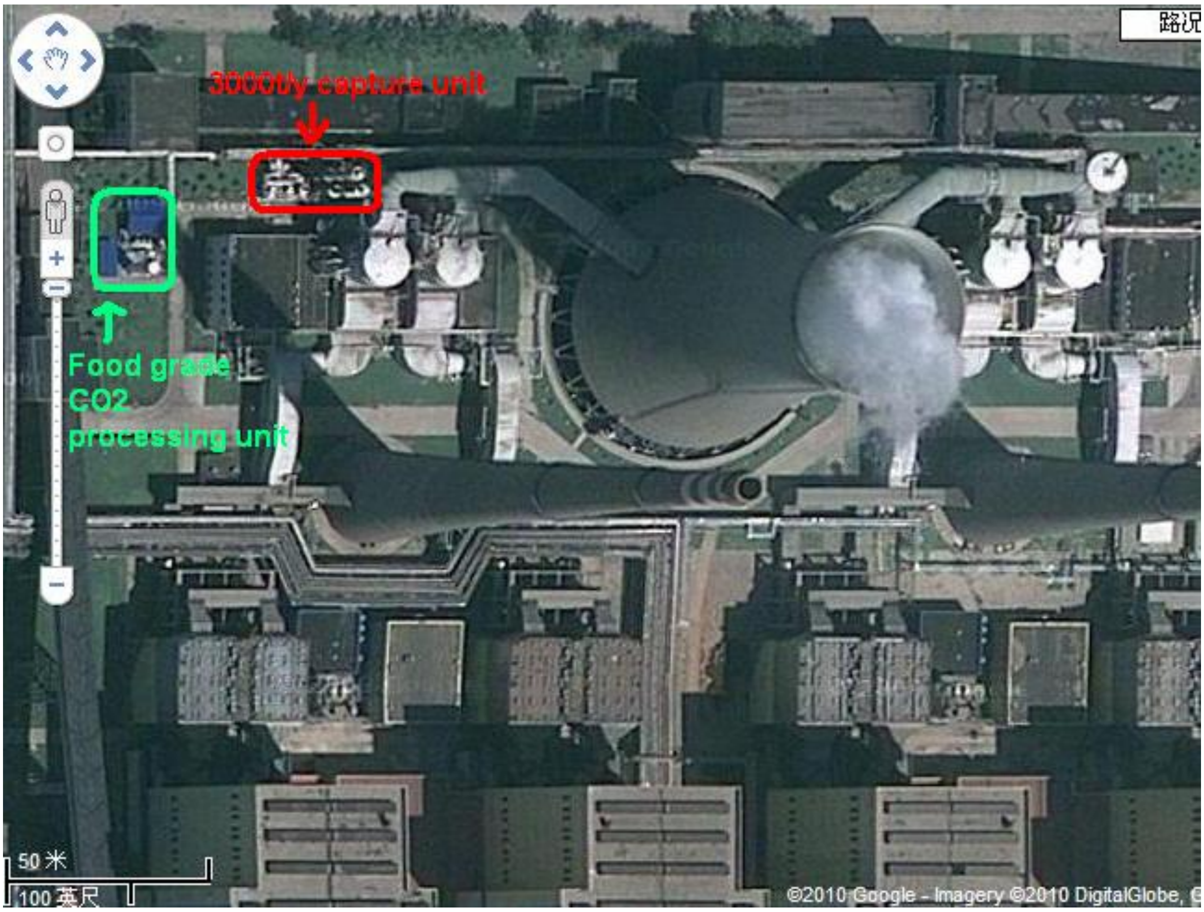


Figure 6.9 Beijing Gaobeidian retrofit units

Figure 6.10 Shanghai Shidongkou retrofit unit (this figure shows the unit while it is still under construction)

6.4 Retrofit potential in Europe

Detailed studies of the retrofit potential for all existing and future fossil power plants in Europe do not appear to have been undertaken. Proposals for regional CCS clusters in the Netherlands around Rotterdam[19] and in the UK in Yorkshire (Yorkshire Forward, 2008) appear to implicitly assume extensive capture retrofitting to existing power plants and other CO_2 sources, however, with local pipeline networks providing the 'access to secure CO_2 storage' side of the retrofit triangle.

The entire EU is, however, covered by legislation requiring new fossil fuel power plants to be built so as to retrofit capture if they meet basic feasibility criteria:

> *1. Member States shall ensure that operators of all combustion plants with a rated electrical output of 300 megawatts or more for which the original construction licence or, in the absence of such a procedure, the original operating licence is granted after the entry into force of Directive 2009/31/EC of the European Parliament and of the Council of 23 April 2009 on the geological storage of carbon dioxide, have assessed whether the following conditions are met:*
>
> *— suitable storage sites are available,*
> *— transport facilities are technically and economically feasible,*
> *— it is technically and economically feasible to retrofit for CO_2 capture.*
>
> *2. If the conditions in paragraph 1 are met, the competent authority shall ensure that suitable space on the installation site for the equipment necessary to capture and compress CO_2 is set aside. The competent authority shall determine whether the conditions are met on the basis of the assessment referred to in paragraph 1 and other available information, particularly concerning the protection of the environment and human health.*

Depending on new plant construction and the timing for the introduction of CCS this legislation could obviously introduce significant potential CCS retrofit opportunities.

An example of the assumed effect of the EU legislation is provided in a recent study of the potential for CCS retrofit to the future UK natural gas CCGT fleet in the 2020's and 2030's (Element Energy, 2010). It was assumed that this fleet would be made up of already (as of 2010) existing plants, whose suitability for retrofit was assessed based on Google aerial images, and new, capture-ready plants that would be inherently suitable for retrofit.

CCGT power plant capacity suitable for retrofit was determined using the following filters:

- *Removal of generation facilities with emissions less than 50ktCO_2 per annum*
- *Site assessment* [using Google images] *based upon plot availability, site access for the remaining sites (i.e. for the addition of a CO_2 pipeline)*

As an example of site assessment (see Figure 6.11) it was stated that

> *For some power stations, there are residential, social or industrial developments adjacent to the sites. Some sites are "bound", i.e. where the surroundings effectively barricade the site in question and no pipeline path is evident, without redevelopment. Consider the example of Enfield CCGT.*

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[19] http://www.rotterdamclimateinitiative.nl/documents/Documenten/RCI-English-CCS%20Brochure-2008.pdf

Here the site is almost fully bound. Access to the South, West and North is via industrial or residential areas severely limiting pipeline access. To the East is a reservoir. There is a very narrow route in the North-East.

Distance to storage was not considered an absolute barrier to CCS retrofit but rather an additional economic barrier. Transport costs could, however, be expected to vary significantly depending on whether or not the plant could access a shared 'strategic' pipeline system.

Figure 6.11 Example of site assessment in UK CCGT retrofit study (Element Energy, 2010)

Only a small fraction of the existing natural gas power generation plants was removed by the filtering above (see Figure 6.12 overleaf). Element Energy (2010) reported that sites considered unsuitable for retrofit (8.32 GW in total and only 2.74 GW of CCGT fleet). Approximately half of the future fleet was estimated to be composed of new plants that were built to be capture ready. It should be noted, of course, that this is only one potential future and significant variations could be seen in reality, including due to as yet uncertain economic and social viability factors. Additionally, as already noted, future CO_2 transport infrastructure development in the UK will affect actual retrofit opportunities. It seems reasonable, however, to conclude that significant potential is likely to exist.

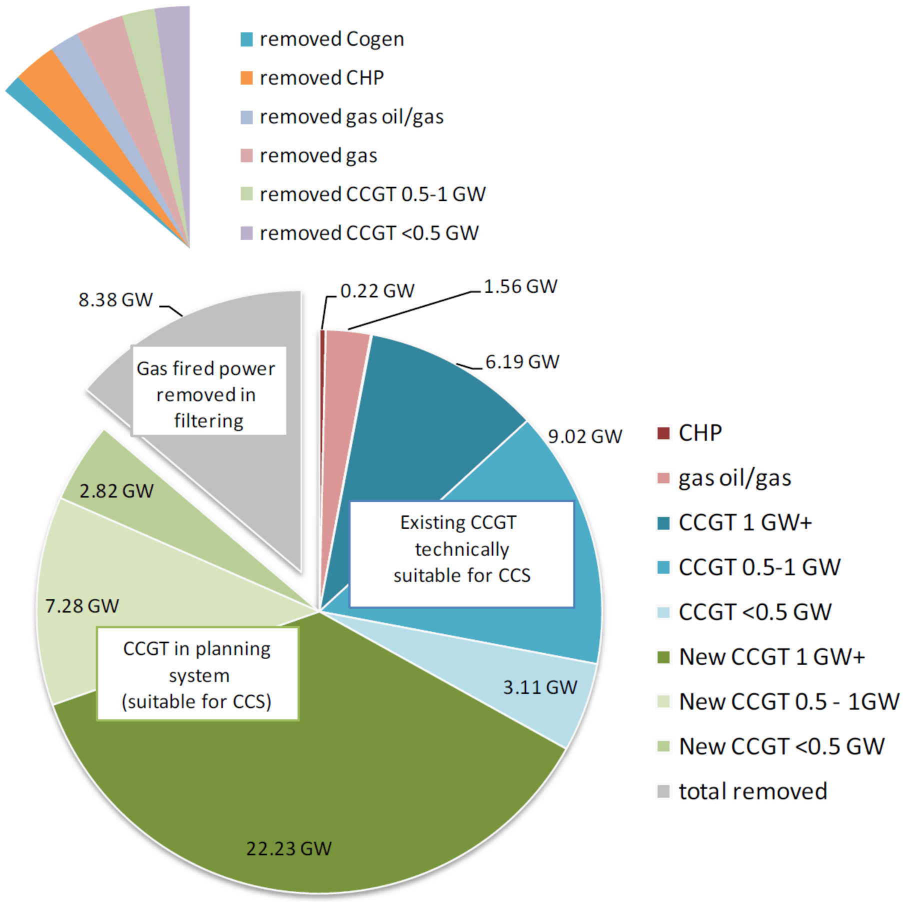

Figure 6.12 Overview of filtering process for CCS retrofit applied to the predicted future UK natural gas generation fleet (Element Energy, 2010)

6.5 Retrofit potential – overall conclusions and recommendations

In the (major) markets where preliminary assessments of the potential for CCS retrofit have been undertaken there appears to be significant potential, based on assessment of existing sites and also, in Europe, the implementation of capture ready regulations for new plants. Quantitative results for some aspects of retrofit potential have been produced in all the studies, but inadequate data for all three aspects of the 'retrofit triangle', technical potential to fit capture equipment, access to storage and economic and social viability (including the actual timing for consideration of retrofitting), precludes any meaningful quantitative assessment of actual future retrofit deployment at present.

Interestingly quite similar site assessment techniques, based on Google images and similar sources, were applied, apparently independently, in all of the studies outlined in this section. This is obviously an area where future work could be useful. Possible improvements might include examination of whether more consistent and less subjective plant image assessment techniques are possible (e.g. based on quantitative image analysis). Comparison with conceptual studies and actual retrofit projects is also becoming increasingly more feasible.

Finally, the number of potential retrofit sites to cover a significant proportion of national installed capacity, even in large markets such as the USA and China, is still only in the hundreds. National databases covering retrofit-related characteristics for each individual site are therefore entirely feasible, and could start with the present studies as a basis. Better information in this area could be of very material assistance, for example for planning CO_2 transport and storage infrastructure or assessing the impact of policy changes, in a period of transition from currently effectively no CCS on power plants to perhaps a time when it becomes the norm under certain circumstances. Such databases could also be used to give quantitative estimates of retrofit potential as better information on all of the required, often site-specific, determining factors became available. Commercial confidentiality may limit the amount of such information that is made available in the public domain, but it is clearly of strategic importance for governments considering the scope for national CO_2 emissions reductions.

7 Conclusions and recommendations

This report has shown that there is a sound theoretical basis for CCS retrofits to existing power plants to be considered as a complement, and in some cases as an alternative, to new build power plants with CCS. In this context, however, it is important that retrofit and new build plant costs are compared using a consistent basis. It is recommended that this basis is the levelised cost of electricity generation for CCS retrofits and new build respectively, assuming zero pre-existing capital charges for the former if the alternative is to close it.

While a large 'jump' in electricity costs is predicted to occur with retrofits, the final overall levelised cost of electricity could still be lower under certain conditions if CCS is retrofitted to an existing plant. In these cases, if the initial electricity costs for this existing plant are taken as the baseline, the jump to the cost of electricity from a replacement new build plant with CCS would be even higher.

CCS retrofits to plants with lower efficiencies will tend to have higher electricity generation costs and so are generally less likely to be competitive with new build CCS replacements, but the strong effect of other site-specific factors on retrofit generation costs makes a definite efficiency threshold for retrofitting inappropriate. Sensitivity analyses suggest that retrofits could be competitive with new build over a wide range of conditions that might be encountered in practice.

Key conclusions from the detailed technical and economic analysis undertaken in this study are that:

- The cost of abatement for different retrofit options is not directly affected by the efficiencies of the plants concerned (as noted above). Some factors are, however, affected by base power plant efficiency, e.g. retrofits to lower efficiency plants cost more per unit electricity produced but capture correspondingly more CO_2.
- While retrofit abatement costs do not vary significantly with efficiency, replacement abatement costs do vary. Hence at existing plants with low base plant efficiency, replacement with new build plant will become a cheaper way of reducing existing plant CO_2 emissions. As noted above, a definite efficiency threshold below which replacement would be preferred cannot specified since the retrofit/replacement decision depends on a number of parameters.
- For a range of conditions that might be encountered in practice it appears that the reduced capture costs for new build CCS plants may be offset by the much higher capital cost of the base power plant itself compared to a retrofit, even if some level of refurbishment to the base power plant is required to achieve an adequate retrofit project life.
- A wide range of theoretical options appear to exist for effective integration of post-combustion (and oxyfuel[20]) capture equipment with the steam cycles of existing coal and gas power plants, which would allow electricity output penalties per tonne of CO_2

[20] The integration of oxyfuel capture equipment, which requires mainly electric power and the effective use of some recovered heat, is much more straightforward in most cases.

captured to be achieved that are close to those for new build plants using the same capture technology.

- If the electricity output of the plant is to be maintained on-site then additional fuel should be used in ways that deliver as much electricity as possible (i.e. natural gas turbine combined cycle or high-pressure steam coal CHP plants); unless a large increase in power output is required it is most effective to combine this with some steam extraction from the main steam turbine.
- As a specific example of the above, while natural gas prices remain attractive it may be advantageous to use relatively small natural gas turbines to make up the power loss, and meet some of the heat requirements, of post-combustion capture retrofits to existing coal plants.

Evidence regarding the potential for CCS retrofits in practice includes:

- CCS retrofit/refurbish/rebuild projects for existing plants currently being proposed for early CCS demonstration projects.
- Surveys of existing plant using Google Earth/Map images in the USA, China and the UK suggest significant numbers of sites exist with space to add capture equipment and access to storage, although a number of uncertainties remain to be resolved and further work is required in this area.
- Especially for older (typically 1970s vintage) coal fired power plants in developed economies there are concerns that plant life after retrofit will not be long enough (15-25 years) to allow recovery of the investment in a CCS retrofit. Preliminary cost estimates as part of a US expert analysis of retrofits suggest that, even with extensive refurbishing to allow this, retrofits may still be cost-effective when compared to building new fossil-fired power plants with (or, in some cases, without) CCS.
- Where new coal (as in China) and natural gas (as in the UK and other developed economies) are being built then concerns about plant life after retrofit are reduced, especially when (as is the case in the UK and possibly elsewhere in the Europe) these have to be built to be capture ready.

The overall recommendation arising from this work is, therefore, that retrofitting CCS to existing power plants is worth examining objectively as an alternative to closing down existing plants and replacing them with new build. A general rejection of retrofitting on grounds such as the age or lower efficiency of existing plants is not justified. More specifically:

- CCS retrofits need to be assessed on a site-specific basis, but the numbers of relevant power plant sites is relatively small. Initial surveys reported here could be extended as ongoing reference databases and be complemented by such additional detailed engineering studies as might be carried out.
- Building new plants to be capture ready obviously increases the probability that they can be retrofitted successfully in the future; the analysis presented in this report suggests that the option of retrofitting these could well be exercised in the future if the alternative were to build new plants with CCS.

Appendix 1 Thermodynamic analysis showing the insensitivity in post-combustion capture efficiency penalty to base power plant efficiency

This Appendix is based on Lucquiaud (2010) and presents a thermodynamic analysis that evaluates the effect of the base-plant efficiency on the efficiency penalty for PCC combined with both subcritical and supercritical plants.

The extent to which the non-site-specific base power plant efficiency, and in particular the peak steam temperature and pressure used in the plant, affects retrofit economics is a topic of concern[21]. There is a question of differentiation between the large number of plants built with steam conditions around the effective limits for sub-critical boiler technology (150-175 bar and 540ºC) which can achieve efficiencies in the range of 36-39% LHV, and the later supercritical steam plants with pressures of 250 bar or higher and steam temperatures of 550ºC to 600ºC with current boiler materials. These supercritical plants currently have typical efficiencies between 40 and 46% LHV when operating at full load. In the future even higher efficiency with 700ºC steam temperatures could be achieved with potential advances in boiler and high pressure steam turbine materials, as shown in Figure A1.1.

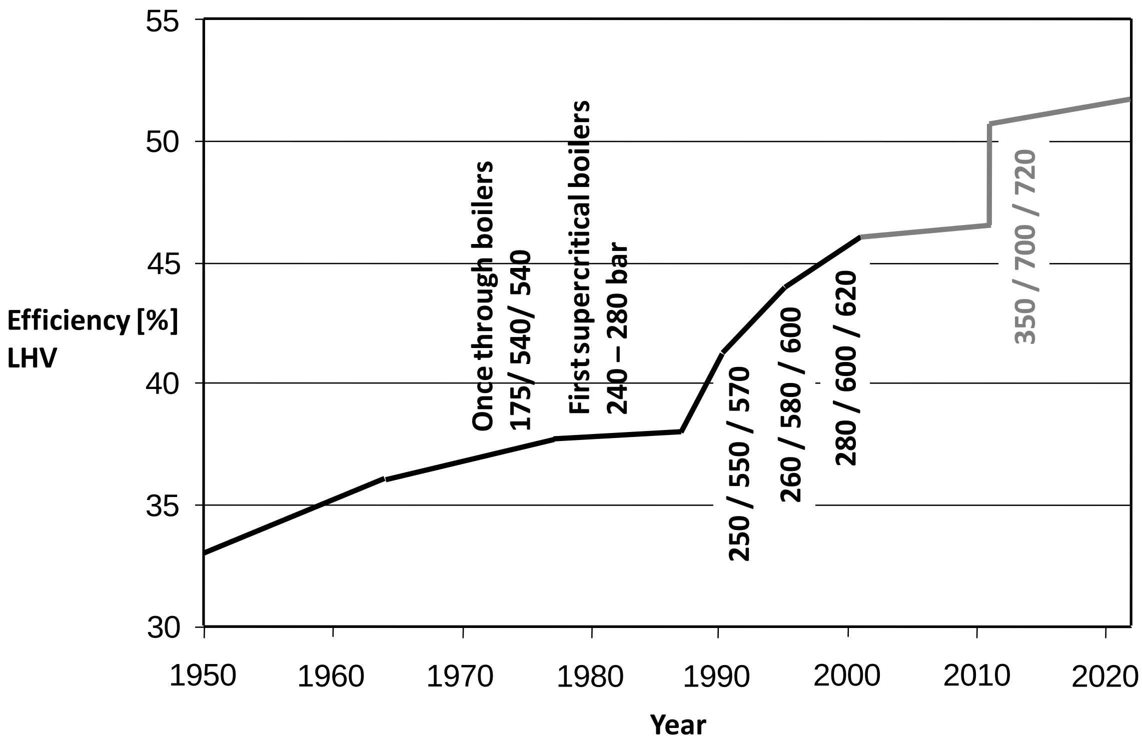

Figure A1.1 Development in EU steam plant efficiency – Steam conditions are shown as HP inlet pressure (bar)/temperature (°C)/reheat temperature (°C) – Adapted from Epple (2004)

An energy balance for a coal-fired plant retrofitted with PCC is provided in Figure A1.Figure A1.2. The power cycle receives an amount of heat, Q_B, from the boiler provided by combustion of the fuel. The energy inputs to the boiler are LHV and $W_{A,}$ respectively the total calorific value of the fuel and the ancillary power for boiler machinery, and the LOSSES term includes principally stack losses and heat losses from the boiler and pipework. Boiler efficiencies are potentially the same for both sub-critical and supercritical steam plants. It

[21] Within this Appendix, variations in plant efficiency due to other site specific factors such as ambient temperature, cooling method, coal properties, duty cycle are not considered.

can, therefore, be assumed that the same amount of heat per unit of fuel burnt, and hence per unit of CO_2 captured, can be transferred to the steam cycle for both plants. The heat will, however, be transferred at a higher average temperature for a supercritical steam plant.

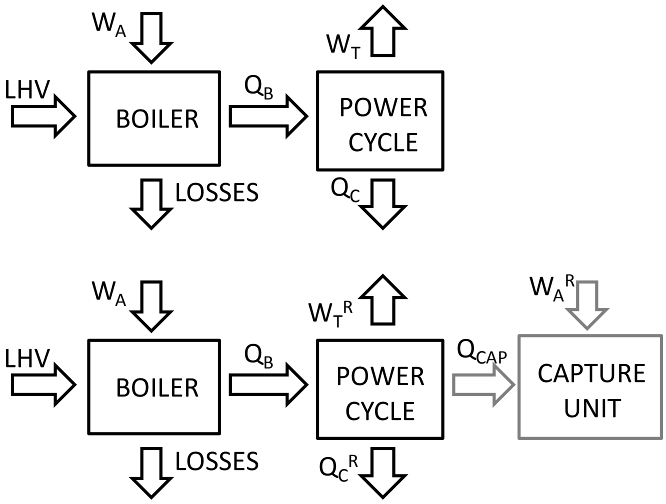

Figure A1.2 1st law analysis of a power cycle without (upper) and with (lower) capture retrofitted

The upper energy balance in Figure A1.2 shows a power cycle without CO_2 capture that generates mechanical work W_T and rejects heat Q_C through the condenser. A reasonable first order approximation is that these together sum to Q_B since other losses are small. When the plant is retrofitted with capture additional heat, Q_{CAP}, is taken from the power cycle and transferred to the capture unit for regeneration of the solvent, along with the ancillary power W_A^R for the capture unit ancillary machinery. It should be noted that Q_{CAP} is the net heat provided for solvent regeneration, allowing for heat recovered in the capture unit for use in the steam cycle (typically for condensate heating).

The efficiency of the plant η and η^R, respectively without capture and when the plant is retrofitted, can be expressed as follows:

$$\eta = \frac{W_T - W_A}{LHV} \qquad \text{(A1.1)}$$

$$\eta^R = \frac{W_T^R - W_A - W_A^R}{LHV} \qquad \text{(A1.2)}$$

The efficiency penalty for capture is then:

$$\eta - \eta^R = \frac{W_T - W_T^R + W_A^R}{LHV} \qquad \text{(A1.3)}$$

Where:

Superscript R	retrofitted plant
η	Plant efficiency based on fuel lower heating value
W_T	Mechanical work output (e.g. in MW_e)
W_A	Ancillary power (e.g. in MW_e)
LHV	Fuel energy input based on low heating value (e.g. in MW_{th})

The loss of mechanical work output caused by steam extraction from the power cycle can alternatively be written as:

$$W_T - W_T^R = Q_B - Q_C - Q_B + Q_C^R + Q_{CAP} \tag{A1.4}$$

$$\boldsymbol{W_T - W_T^R = Q_{CAP} - (Q_C - Q_C^R)} \tag{A1.5}$$

$$W_T - W_T^R = Q_{CAP} - (\dot{m}_C * (h_{steam} - h_{liq}) - \dot{m}_C^R * (h_{steam}^R - h_{liq}^R)) \tag{A1.6}$$

$$\boldsymbol{W_T - W_T^R = Q_{CAP} + \dot{m}_C * [(h_{steam}^R - h_{steam}) - (h_{liq}^R - h_{liq})] - (\dot{m}_C - \dot{m}_C^R) * (h_{steam}^R - h_{liq}^R)} \tag{A1.7}$$

Where:

Superscript R	retrofitted plant
Q_B	heat input from boiler to steam cycle (e.g. in MW_{th})
Q_C	heat rejected by the condenser (e.g. in MW_{th})
Q_{CAP}	Net heat taken from the power cycle for regeneration of the solvent (e.g. in MW_{th})
$\dot{m}_C$	steam cycle condenser steam flow without capture (e.g. in kg/s)
h_{steam}	stagnation enthalpy per unit of mass of steam at low pressure turbine outlet (e.g. in MJ/kg)
h_{liq}	stagnation enthalpy per unit of mass of condensate at condenser outlet (e.g. in MJ/kg)

The efficiency penalty can then be written as the sum of two terms. The first one depends solely on the performance of the PCC system, while the second one is specific to the plant configuration:

$$\eta - \eta^R = \frac{\boldsymbol{Q_{CAP} + W_A^R}}{\boldsymbol{LHV}} + \frac{\boldsymbol{+\dot{m}_C * [(h_{steam}^R - h_{steam}) - (h_{liq}^R - h_{liq})] - (\dot{m}_C - \dot{m}_C^R) * (h_{steam}^R - h_{liq}^R)}}{\boldsymbol{LHV}} \tag{A1.8}$$

For the purpose of comparing a sub-critical and supercritical plant the following parameters can be assumed to be identical, since they are site specific factors that are not intrinsically related to the steam conditions:

- Coal properties, specifically calorific value and the quantity of carbon dioxide produced per unit heat;
- Boiler efficiencies, so that the amount of heat transferred to the power cycle $Q_B$is the same;
- By extension these two assumptions imply that the fuel specific emissions are the same;
- Ambient conditions, cooling systems and low pressure turbine exit dryness fraction, so that condenser pressure is the same;
- Steam extraction pressure at the point it leaves the steam cycle and low-grade heat use for condensate heating; and
- Capture unit design and operation, so that the output penalty per mass of CO_2 captured are identical

Therefore for both units the amount of heat extracted from the steam cycle Q_{CAP} and the ancillary power for capture W_A^R for the same fuel input are the same. The efficiency penalty, in terms of percentage points of efficiency lost, for the sub-critical and the supercritical plants is then identical, except for any variation in the value of the second term:

$$\boldsymbol{\dot{m}_C * [(h_{steam}^R - h_{steam}) - (h_{liq}^R - h_{liq})] - (\dot{m}_C - \dot{m}_C^R) * (h_{steam}^R - h_{liq}^R)} \tag{A1.9}$$

Provided that the same condenser pressure and exit dryness fraction for the low pressure turbine are used, the steam and condensate enthalpies (h_{steam} and h_{liq}) in the condenser are identical for sub- and supercritical units without capture. If an equally efficient method of integration is employed for capture retrofit to the sub-critical and the supercritical plant[22], the reduction in steam flow to the condenser ($\dot{m}_C - \dot{m}_C^R$) is also the same for both types of plants. The difference in the efficiency penalty is, thus, only a function of the condenser mass flow without capture, $\dot{m}_C$, and the (possibly) changed steam enthalpies in the condenser (h_{steam}^R and h_{liq}^R).

When supercritical and sub-critical plants are compared for the same boiler heat input to the power cycle, a sub-critical plant produces less power without capture, rejects more heat through the condenser and therefore has a higher condenser mass flow without capture, $\dot{m}_C$. This higher original mass flow means that the relative change in the mass flow through the condenser $\frac{(\dot{m}_C - \dot{m}_C^R)}{\dot{m}_C}$ is smaller for the subcritical plant. This directly affects the extent to which the condenser pressure drops when CO_2 capture is retrofitted. If the cooling water flow is maintained, a lower drop in condenser pressure for the sub-critical plant is observed. Slightly higher values for h_{steam}^R and h_{liq}^R could, therefore, expected for a sub-critical plant retrofitted with CO_2 capture than for a supercritical plant. On the other hand a smaller relative change of the mass flow through the LP turbine results in a smaller drop in the isentropic efficiency of the LP turbine of a sub-critical plant. This would tend to make h_{steam}^R and h_{liq}^R lower than for a supercritical plant for a given condenser pressure, which tends to counteract the previous effect.

Additionally, it can be shown that the magnitude of this second term (equation A1.9) is relatively small. Values for h_{steam}^R and h_{steam} are of the order of 2300-2320 kJ/kg and for $h_{liq}$and h_{liq}^R of the order of 120-160 kJ/kg, with likely relative changes of the order of 30 kJ/kg for both h_{steam} and h_{liq} when CO_2 capture is added. Due to the competing factors outlined above, the difference in the magnitude of the enthalpy changes when supercritical and sub-critical plants are compared is, thus, likely to be limited to 5 kJ/kg maximum. A 600MW$_e$ retrofitted unit operating with capture has a condenser mass flow of the order of 250-300kg/s, once approximately 50% of the low pressure turbine flow is extracted. Variations in condenser pressure between sub- and supercritical plants, thus, account for a difference in power generated of maximum 1-1.5 MW$_e$.

A similar analysis can be made on the sensitivity to boiler efficiency, which was previously assumed to be constant. If we now consider the case of a plant with a high boiler efficiency and a plant with a low boiler efficiency, but with the same steam cycle efficiency, a similar counter effect on the LP turbine output occurs. With a more efficient boiler the steam cycle generates more power through a higher steam flow, and hence a higher LP turbine and condenser steam flow ($\dot{m}_C$). When steam is extracted for CO_2 capture, the lower reduction in the isentropic efficiency of the low pressure turbine, which is beneficial for the overall plant

[22] Steam turbine and other retrofit options to achieve this objective are discussed in Appendix 3.

output, counterbalances the lower drop in condenser pressure which is detrimental for power output. In addition, it should be noted that overall boiler efficiencies do not vary much between sub- and supercritical units.

Therefore, to a very close approximation, this analysis shows that the plant steam conditions, and by extension the plant efficiency, have no significant direct effect on the efficiency penalty of a CO_2 capture retrofit. Instead, the efficiency penalty for CO_2 capture retrofit depends on site specific considerations, e.g. the condenser heat transfer surface or the LP turbine efficiency profile at reduced flow. The effects of site-specific parameters are likely to be small compared to the influence of the capture system characteristics and can only be evaluated on an individual basis.

Appendix 2 Capture energy requirements as a function of fuel composition for coal plant post-combustion capture

This Appendix is based on Lucquiaud and Gibbins (2010b) and explores changes in energy requirements for PCC for different fuel compositions. The analysis shows that the composition of the coal used, and the boiler design, is an important parameter when comparing two potential retrofit sites, or when selecting between different coals for the same plant. The type of coal burnt can have a significant effect on the overall efficiency penalty of CCS.

The energy required for PCC is directly proportional to the amount of CO_2 captured, when expressed in lost electrical output per tonne of CO_2 captured, and is effectively independent of the base plant efficiency as shown in Appendix 1. When considering a possible retrofit project, the amount of CO_2 that must be captured to achieve a particular emission level (e.g. in kg CO_2 per MWh electrical output) obviously then depends on the plant efficiency. It is, however, an equally good use of energy to capture CO_2 produced by a sub-critical or a supercritical plant burning the same fuel. In contrast, coal composition has a direct effect on the total amount of CO_2 generated in the flue gas per unit of energy transmitted to the power cycle, and thus on the electricity output penalty of CO_2 capture. The ratio between the fuel heating value and the carbon content and also the fuel heating value and the moisture content are all important.

Dulong's formula is one of the best known, and the most extensively used, method to predict a coal calorific capacity as a function of its composition (Lowry, 1963) and is shown in equation A2.1. In this formula, it is assumed that the oxygen contained in the coal is associated with hydrogen in the proper ratio to form water. The excess hydrogen and also carbon and the sulphur are available for combustion.

$$\mathbf{GCV} = \mathbf{14554} * C + \mathbf{62028} * \left(H - \frac{O}{8}\right) + \mathbf{4050} * S \tag{A2.1}$$

Where:

GCV	BTU/lb	Gross calorific value of the fuel
C	%	Fuel carbon content on a dry matter free mass basis (ultimate analysis)
H	%	Hydrogen carbon content on a dry matter free mass basis (ultimate analysis)
O	%	Oxygen carbon content on a dry matter free mass basis (ultimate analysis)
S	%	Sulphur carbon content on a dry matter free mass basis (ultimate analysis)

Based on lower heating value, so with water in the combustion products assumed to be in a gaseous state, a fuel's specific CO_2 emissions (i.e. $kgCO_2$/MWh) can be expressed as:

$$E = \frac{C * (1 - H2O - ash) * {}^{M_{CO2}}/_{M_C}}{(GCV * {}^{2.326}/_{1000} - H * {}^{M_{H2O}}/_{M_H} * \Delta h_{lat}) * (1 - H2O - ashh) - H2O * \Delta h_{lat}} \tag{A2.2}$$

Where:

E	kg CO_2/MWh	Fuel specific emissions on a LHV basis
H_2O	%	Water content on mass basis (proximate analysis)
Ash	%	Ash content (proximate analysis)

M_{CO2}	kg/mol	Molar mass of carbon dioxide, 44.01
M_C	kg/mol	Molar mass of carbon, 12.01
M_{H2O}	kg/mol	Molar mass of water, 18.016
M_H	kg/mol	Molar mass of hydrogen, 2.016
Δh_{lat}	MW_{th}/kg	Latent heat of vaporisation of water, 2.442

The UK Seyler Coal Chart in shown in Figure A2.1 (Lowry, 1963). This chart can be used to determine typical coal compositions, as in the sensitivity analysis of specific emissions of a range of different coals shown in Figures A2.2 and A2.3. Three moisture contents (0%, 25% and 50% on a mineral matter free basis) are shown and it is assumed that:

- carbon content varies from 70 to 85%;
- hydrogen content is constant at 5% mass basis over this carbon range;
- sulphur and nitrogen contents can be neglected; and
- the oxygen content is then found by difference.

Boiler efficiency has only a marginal effect on the efficiency penalty of PCC (see Appendix 1) and the purpose here is to compare existing power plants suitable for a retrofit. It can, therefore, be assumed that the combustion of each type of coal represented here occurs at the best combustion and heat transfer conditions possible.

Figures A2.2 and A2.3 show that the effect of moisture on fuel specific emissions is not linear; the higher the carbon content, the weaker the effect of moisture. An increase of 2.5-3.5% in specific emissions is observed at 25% moisture for the carbon contents considered, compared to the hypothetical dry coal with 85% carbon and no moisture. At 50% moisture carbon content has a stronger effect. Specific fuel emissions increase from an additional 8% at 85% carbon content, compared to the range of base coal with no moisture, to 11% at 75% carbon content.

As far as ash is concerned, specific emissions increases marginally with the ash content; a change of the order to 0.4-0.6% maximum is observed when the ash content varies from 0% to 30% over the range of carbon content considered here with 10% moisture, as shown in Figure Figure A2.4. It should be noted that the ash content is not reported here in a standard manner and that the ash content changes the ratio between the moisture and the dry ash free coal. Nonetheless, this does not affect the conclusion that the influence of the ash content is negligible.

Figure A2.5 illustrates the efficiency penalty of PCC, expressed in percentage points of LHV power plant efficiency, for three moisture contents. It shows that carbon and moisture content can drastically change the efficiency of power plants with PCC. The reference case is a coal containing 85% carbon, no moisture and no ash in a plant with an electricity output penalty of 300 kWh/tCO_2 plant for capture and compression. The efficiency penalty, expressed in percentage point LHV, of PCC increases by 0.8 to 1.1 percentage point, depending on the moisture content, when the carbon content decreases from 85% to 70%. It increases by a further 0.5 to 0.8% percentage point when the moisture content changes from 25% to 50%. Future improvements in PCC are, however, likely to reduce the absolute magnitude dependence of the efficiency penalty on the coal composition.

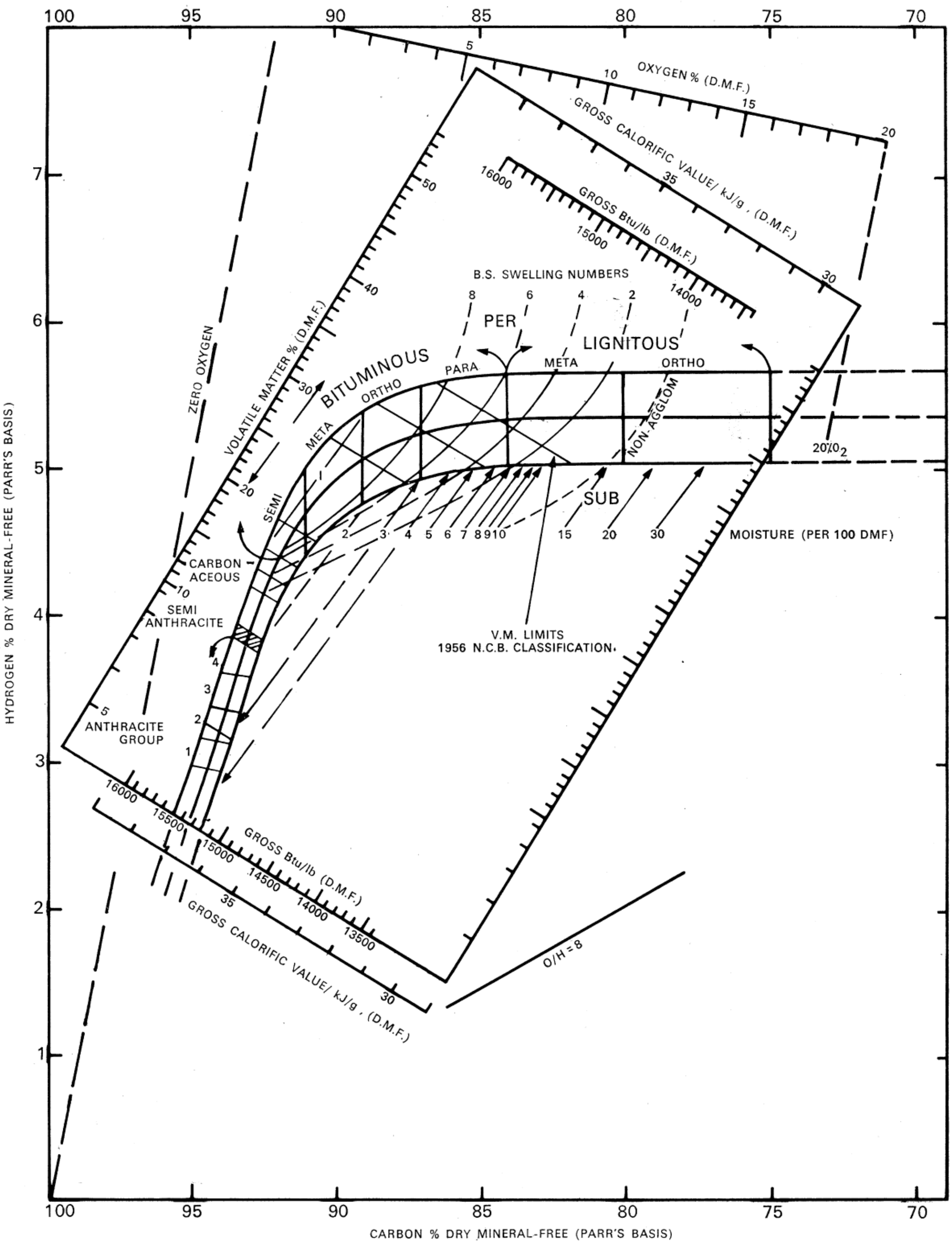

Figure A2.1 Seyler's coal chart (for UK coals)

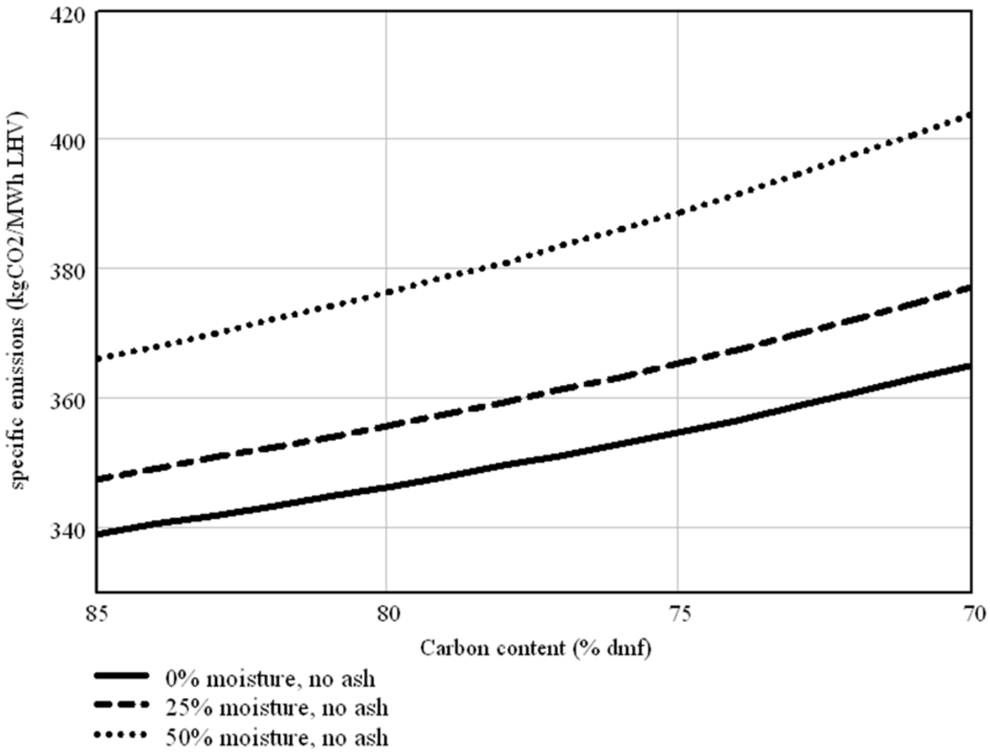

Figure A2.2 Specific CO_2 emissions of coal as a function of carbon and moisture content

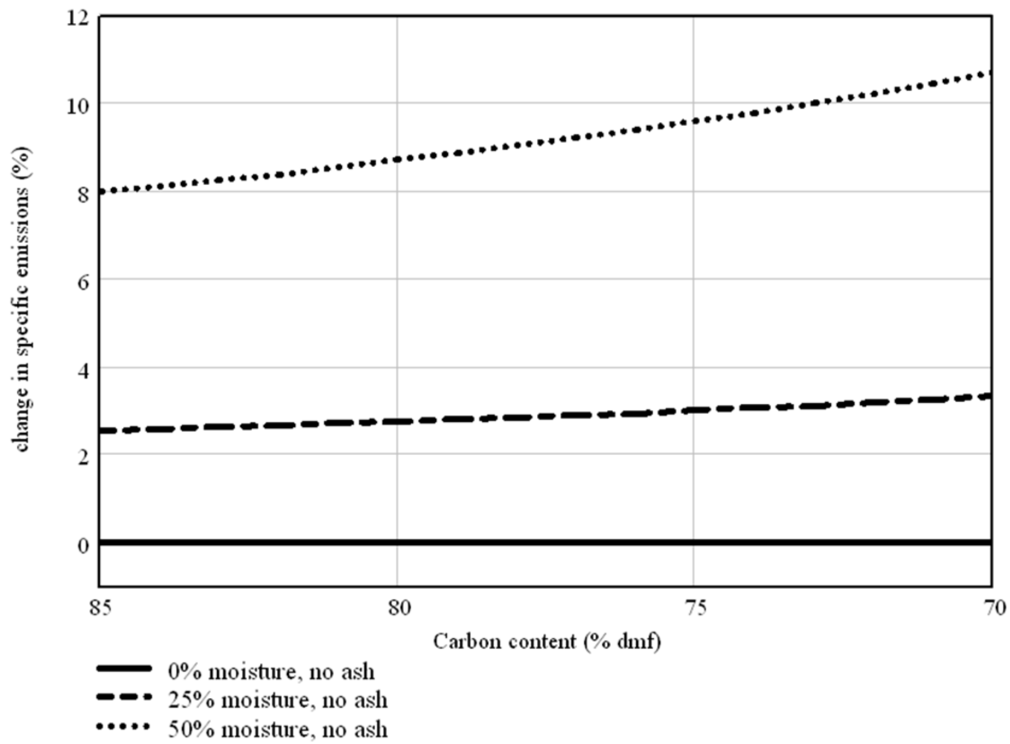

Figure A2.3 Variation in the specific emissions of coal with moisture content over a range of carbon contents

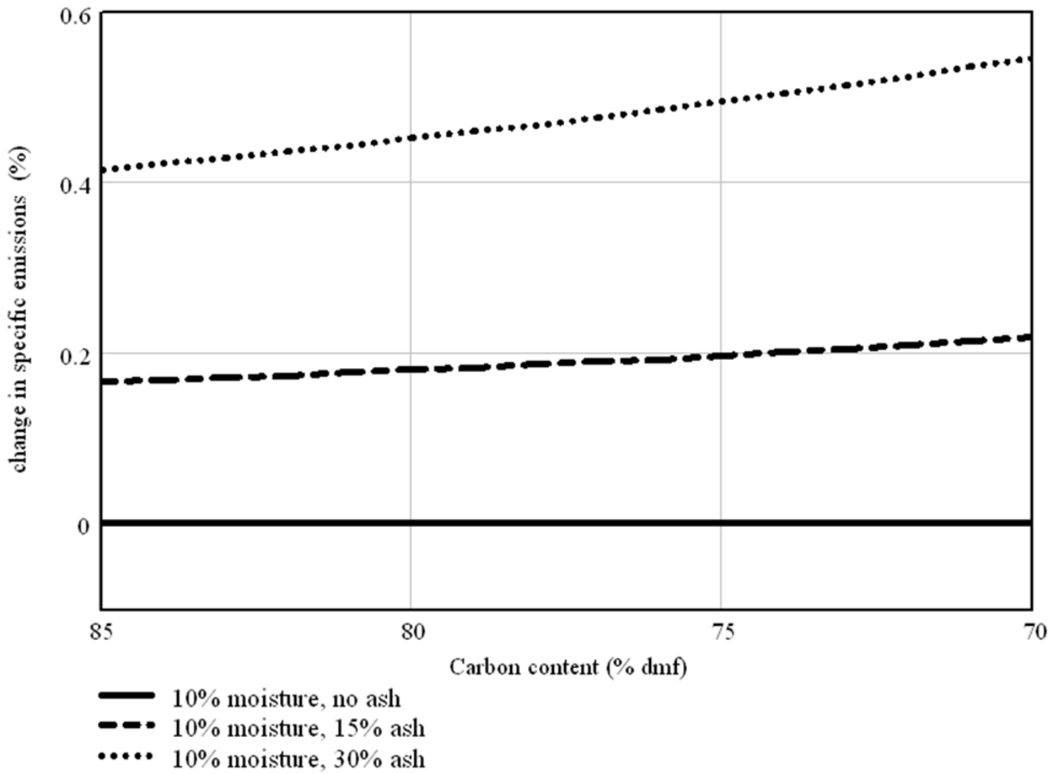

Figure A2.4 Variations of the specific emissions of coal with ash content

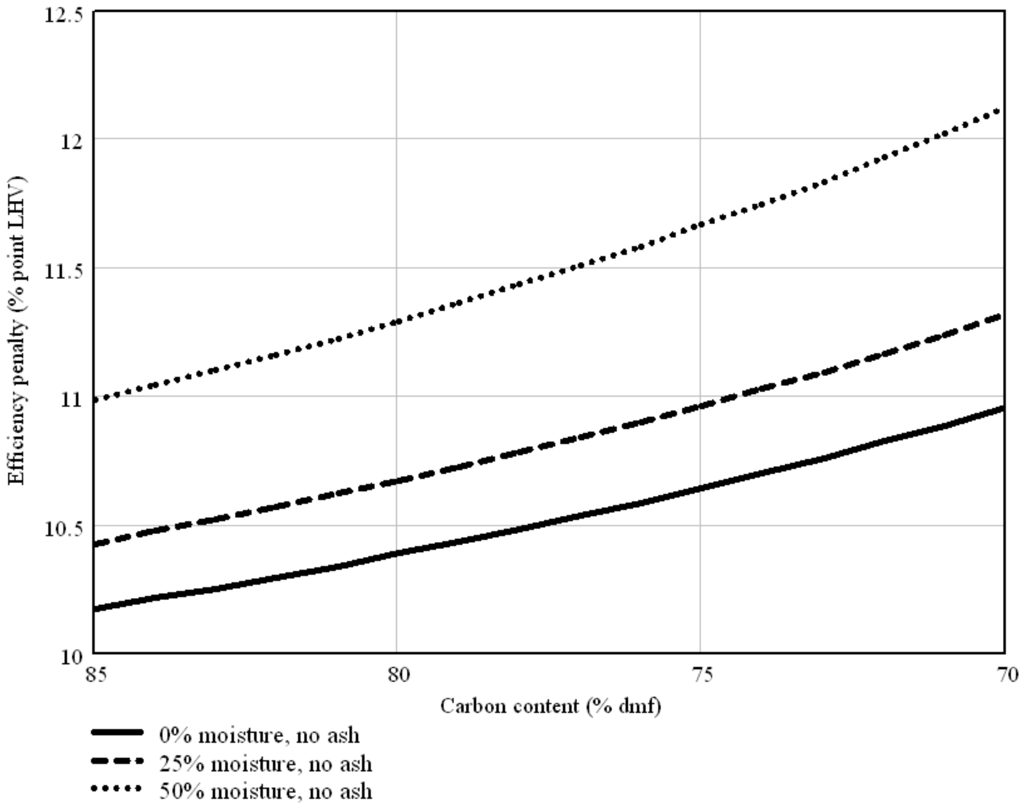

Figure A2.5 Variation in the efficiency penalty of post-combustion capture with coal type Base case: Coal with 85% C, 0% moisture content and no ash. Electricity output penalty for capture and compression of 300 kWh/tCO_2

Appendix 3 Steam turbine retrofits for post-combustion capture

This Appendix is based on Lucquiaud (2010) and summarises work informing steam turbine retrofit decisions for CO_2 capture retrofit. The integration of PCC systems with the steam cycle of new-build plants operated at base load has been studied extensively, with the aim of reducing the energy penalty independently of the specific solvent regeneration energy requirements. The approaches proposed are, however, unlikely to be practical for much of the existing fleet of coal-fired plants, which have a wide range of IP turbine exit pressures.

For example, a study commissioned by the US Department of Energy National Energy Technology Laboratory (Ramezan et al, 2007) examined the site-specific retrofit of a coal-fired unit based at Conesville, Ohio, USA, with an IP turbine outlet pressure of 13.4 bar. This is considerably higher than the pressure required in the capture plant reboiler for the MEA solvent used in this work. A requirement to maintain the capacity for operation with the capture plant bypassed to permit the maximum generator output to be obtained, meant that "permanent modifications [to the turbines and generator] were not possible". The study also assumed that the IP/LP crossover pressure would not be reduced, on the basis that "the exhaust section of the IP turbine and the existing blading would not be able to withstand this increased mechanical loading" (although no further details on the high cycle endurance fatigue or tensile strength of the IP blades were given). During operation with retrofitted CO_2 capture it was decided that the LP turbine inlet would be throttled to maintain the IP turbine outlet pressure. The steam extracted for use in the CO_2 capture plant was expanded through a back pressure turbine, before leaving the steam turbine hall to go to the solvent reboiler.

A schematic diagram of the Conesville retrofit, with the addition of a desuperheating feed water heater in the steam extraction line instead of a spray desuperheater, for consistency with the rest of the work presented here, is provided in Figure A3.1. Throttling losses in the LP inlet valve inevitably resulted in an electricity output penalty higher than for a capture plant in which throttling would not be required. In addition, Ramezan et al (2007) also reported a relatively high delivery pressure for the steam leaving the boundaries of the steam cycle to the capture plant (4.5 bar, compared to the 3.6 bar reboiler steam supply pressure). This also increases the electricity output penalty since it reduces the electrical output of the main steam cycle. A higher pressure such as this could be a consequence of the remote location of the capture plant from the turbine island, with increased pressure drop in the connecting pipes. It could also result from a decision to reduce the size of the solvent reboiler, which would reduce capital expenditure but at the expense of a higher electricity output penalty.

Comparative results from other studies for new-build plants and retrofits of CCR (CO_2 capture ready) units, where the IP turbine outlet pressure was selected to be at a lower pressure, are provided in Table A3.1. This shows that the retrofit option proposed by Ramezan et al (2007) has a significantly higher electricity output penalty for CO_2 capture. This highlights the need to update the third rule for thermodynamic integration proposed by Gibbins et al (2004a) for new-build plants with PCC when retrofits are considered as follows, as outlined in Section 3.2.2. Originally, Gibbins et al (2004a) stated:

3. Produce as much electricity as possible from any additional fuel used, consistent with rejecting heat at the required temperature for solvent regeneration.

Lucquiaud (2010) updated this to be:

3. Produce as much electricity as possible *from the power cycle (i.e. be prepared to use additional turbines for retrofit projects if commercially justified)* and from any additional fuel used, consistent with rejecting heat at the required temperature for solvent regeneration.

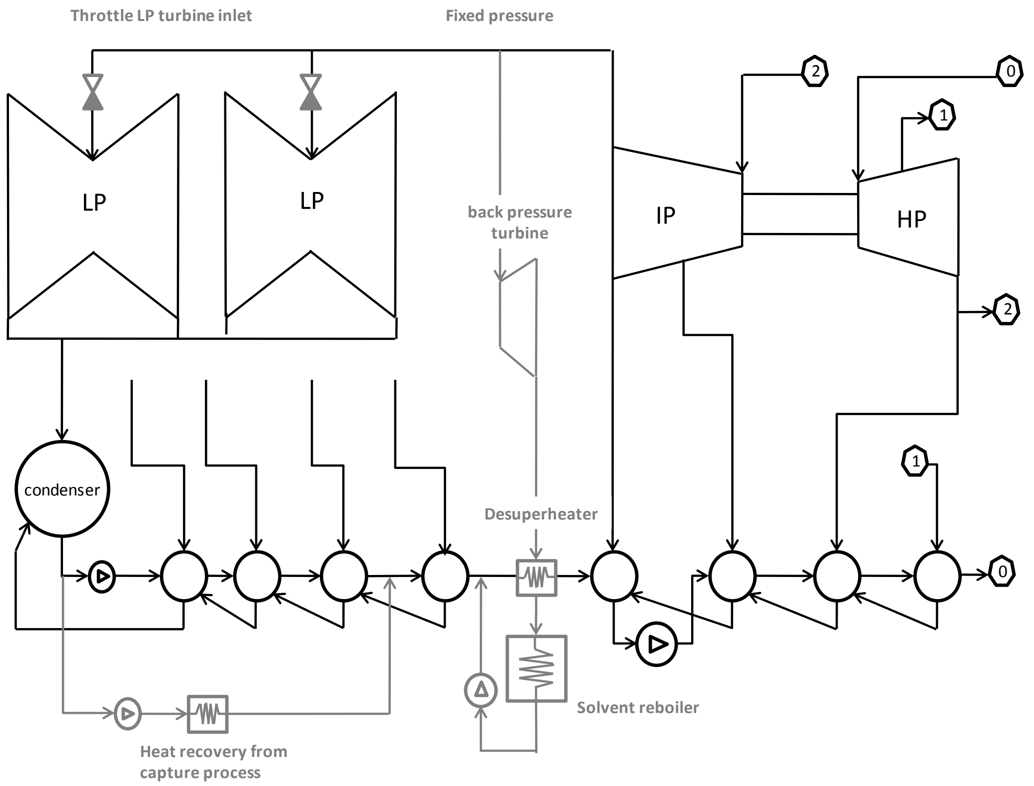

Figure A3.1 Steam turbine retrofit with a fixed crossover pressure and a single back-pressure turbine

Table A3.1 Comparison of the electricity output penalty of industry studies

Source	IEAGHG (2004b) MHI case	IEAGHG (2004b) Fluor case	Panesar et al (2009) Fluor	Ramezan et al (2007) MEA case	Ramezan et al (2007) future solvent case
Solvent heat of regeneration (GJ_{th}/tCO_2)	2.8	3.24		3.6	2.8
Reboiler steam supply pressure (bara)	3.24	3.24		4.5	4.5
Electricity output penalty (kWh/tCO_2)	286.5	320.7	319.5	368.9	323.7
Ancillary power electricity output penalty (kWh/tCO_2)	146.0	136.0		155.3	155.3
Steam cycle electricity output penalty (kWh/tCO_2)	150.5	174.7		213.5	168.4

A gPROMs model has been used to examine the performance of alternative steam turbine options for the retrofit of the steam cycle of an existing unit, following the updated integration rule above. Flexibility is provided within the model to represent a range of IP turbine outlet pressure and solvent heat of regeneration. For consistency, it is assumed that the boiler efficiency and the ancillary power of the CO_2 compression train are constant for each configuration. In this example a supercritical pulverised coal boiler delivers steam at 242bar and 565ºC at the HP turbine inlet and 42.1 bar and 566ºC at the IP turbine inlet respectively. This is based on the existing steam cycle configuration without capture at a Chinese pulverised coal unit provided within the NZEC project[23]. The IP turbine outlet pressure is initially set to 11.1 bar.

When the plant is retrofitted and operates with capture, the LP condensate heaters are retained and receive 10% of their design mass flow to keep them at temperature so that they can be used to facilitate rapid changes in capture levels and power output. For this illustrative study the solvent regeneration temperature is assumed to be 120ºC, the temperature difference in the reboiler is 15K and the pressure drop across the connecting pipe from the turbine island to the solvent reboiler is 0.5 bar. A sensitivity analysis of these values is presented in later in this Appendix.

Effective thermodynamic integration of the turbine with the capture process implies that as much power as possible is recovered from both the extracted steam going to the reboiler and the remaining steam entering the LP turbine. This should not, however, compromise the ability of the retrofitted plant to return to operation with maximum generation output. For example, for a given solvent and IP turbine outlet pressure it might be possible to recover the maximum mechanical work available in the steam leaving the IP turbine by converting one of a pair of LP cylinders to back pressure operation. This could be achieved by removing a suitable number of LP stages so that steam from that cylinder could go to the reboiler instead of to a conventional condenser. This permanent modification would, however, lock the plant into operation with capture if full electricity output (and fuel input) are to be achieved and also allow only limited changes in the solvent.

[23] The joint UK-China Near Zero Emissions Coal (NZEC) initiative, http://www.nzec.info/en/

Retrofits aiming for solvent upgradability, flexible capture and maximum efficiency should seek to maintain the full original steam swallowing capacity of the LP turbine (for upgradability and flexibility). They should also avoid (or, at least, minimise) the use throttling valves to restrict the steam flow through the LP when capture is retrofitted if maximum efficiency is to be obtained. One option for achieving this is shown in Figure A3.2 where two let-down back-pressure turbines are fitted, in the extraction line and between the LP and IP turbine. The back pressure turbine at the inlet of the LP turbine is by-passed without capture. At intermediate capture levels between 0 and 90% capture both additional turbines are partially bypassed.

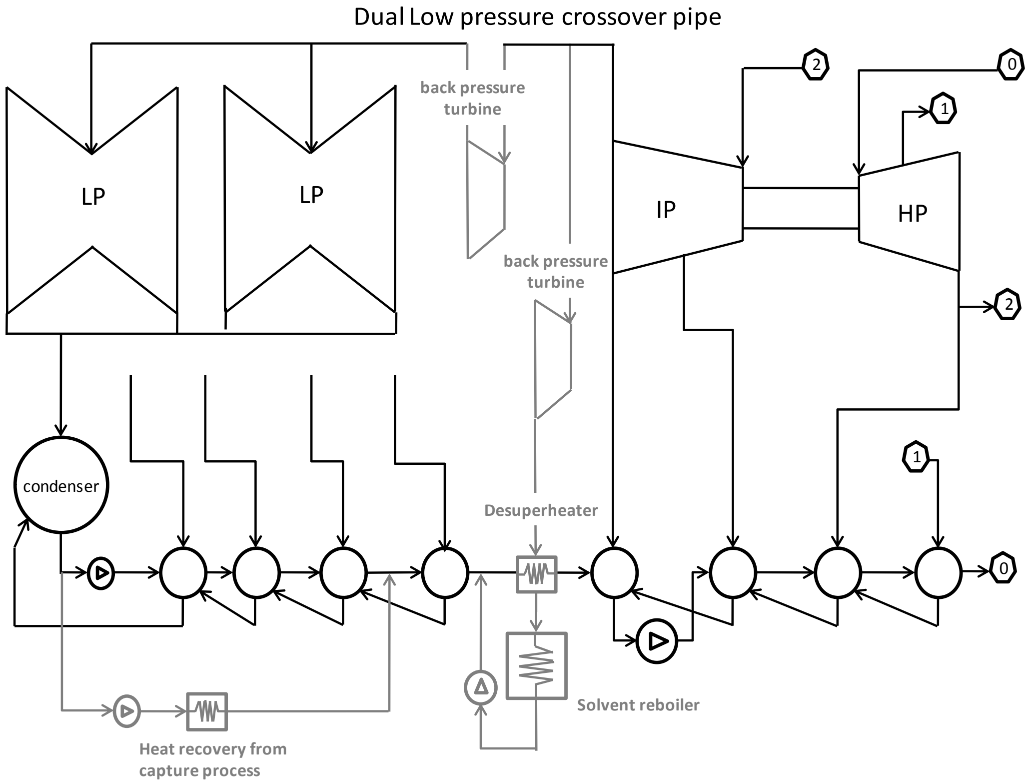

Figure A3.2: Steam turbine retrofit with a fixed intermediate pressure turbine outlet and two let-down back-pressure turbines

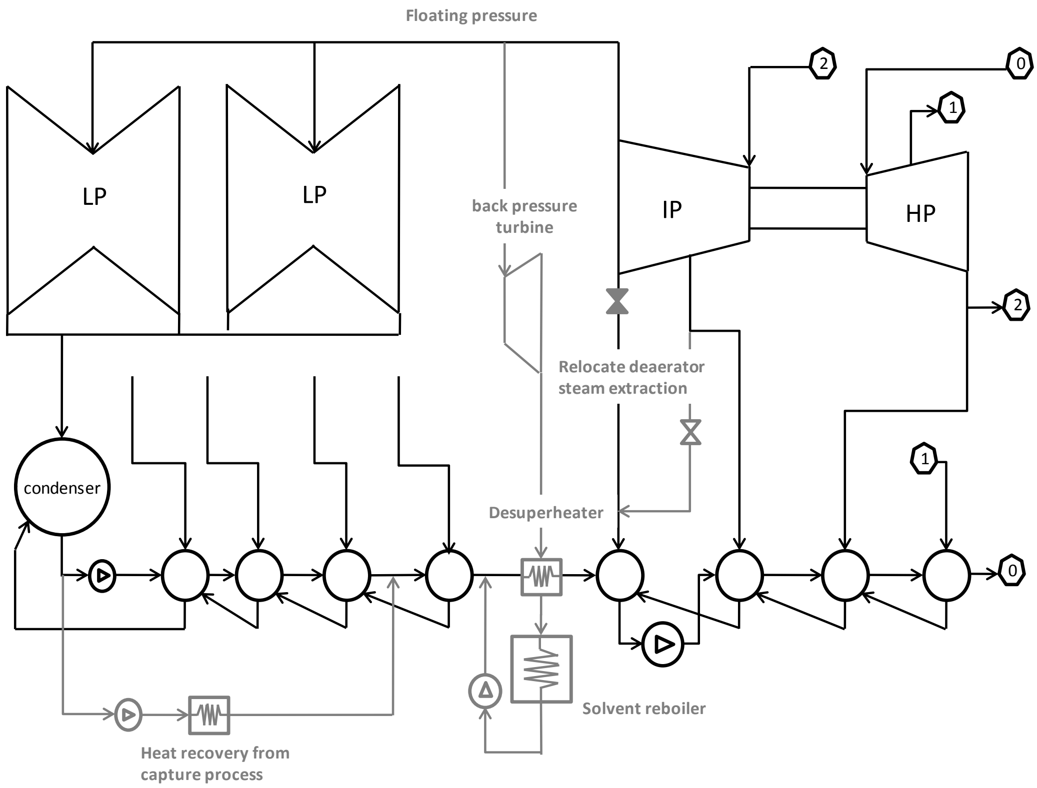

Figure A3.3: Steam turbine retrofit with a floating intermediate pressure turbine outlet and a let-down back pressure turbine

A second option is shown in Figure A3.3. In this case, additional steam expansion occurs in the very last stages of the IP turbine while the LP turbine swallowing capacity is left unchanged. The supply pressure to the reboiler is not controlled by a valve but rather by the amount of steam extracted at the IP outlet. The crossover pressure is directly related to the mass flow entering the LP turbine and approximated in this analysis by the Stodola ellipse law (Stodola, 1927). At intermediate capture levels the pressure floats between the 90% capture and no capture values and the back pressure turbine in the reboiler line is throttled. Without capture the steam cycle returns to an operating regime similar to the conditions before retrofit.

This concept is somewhat similar to the floating IP outlet pressure system proposed for CCR steam turbines (see Lucquiaud and Gibbins, 2009a), with the addition of a back pressure turbine expanding the steam extracted from the new IP/LP crossover pressure to the reboiler pressure. The change of pressure ratio across the IP turbine changes the enthalpy drop per stage, increases the steam inlet velocity relative to the blade, modifies the velocity triangle in the rotor and therefore reduces the isentropic efficiency of the IP stages. Bending moments and other mechanical stress on the blades and the end thrust on the IP turbine are all also increased. These considerations are discussed further below.

Figure A3.4 shows a comparison of the electricity output penalty for base-load operation between the two options above and a retrofit using a throttle valve to reduce the flow through the LP turbine, as in Ramezan et al (2007). A range of initial (before capture) IP turbine outlet pressures are considered. Additionally, retrofit options with and without heat recovery from the capture and compression units are reported.

With a valve at the LP turbine inlet and the addition of a back-pressure turbine in the extraction line the EOP (electricity output penalty) accounts for approximately 310-315 kWh/tCO_2, and is higher for elevated crossover pressures. This indicates that higher throttling losses occur with elevated crossover pressures, although the effect is relatively small compared to the absolute value of the EOP. They account for an increase of 33-38 kWh/tCO_2 compared to the option with two back-pressure turbines, which has a constant EOP of approximately 277 kWh/tCO_2 across the range of IP turbine outlet pressures. Finally the floating pressure system with a back pressure turbine provides a constant EOP of the order of 280-285 kWh/tCO_2 for IP/LP crossover pressures above 7 bar. The difference when compared to the retrofit with two back-pressure turbines is principally due to modifications in the HP feed water heating system. As the outlet pressure of the IP turbine drops the pressure of the deaerator tapping point is reduced too. The deaerator then has to be fed from a higher pressure tapping point, as shown in Figure A3.3. This leads to a less efficient operation of the HP feed water heating system. For IP/LP crossover pressures below 7 bar the IP outlet pressure drops down to the reboiler supply pressure before the required amount of steam is extracted and hence some amount of throttling at the LP turbine inlet has to occur to maintain the reboiler steam pressure. The performance is then intermediate between that of the unthrottled and the throttled systems, as would be expected intuitively.

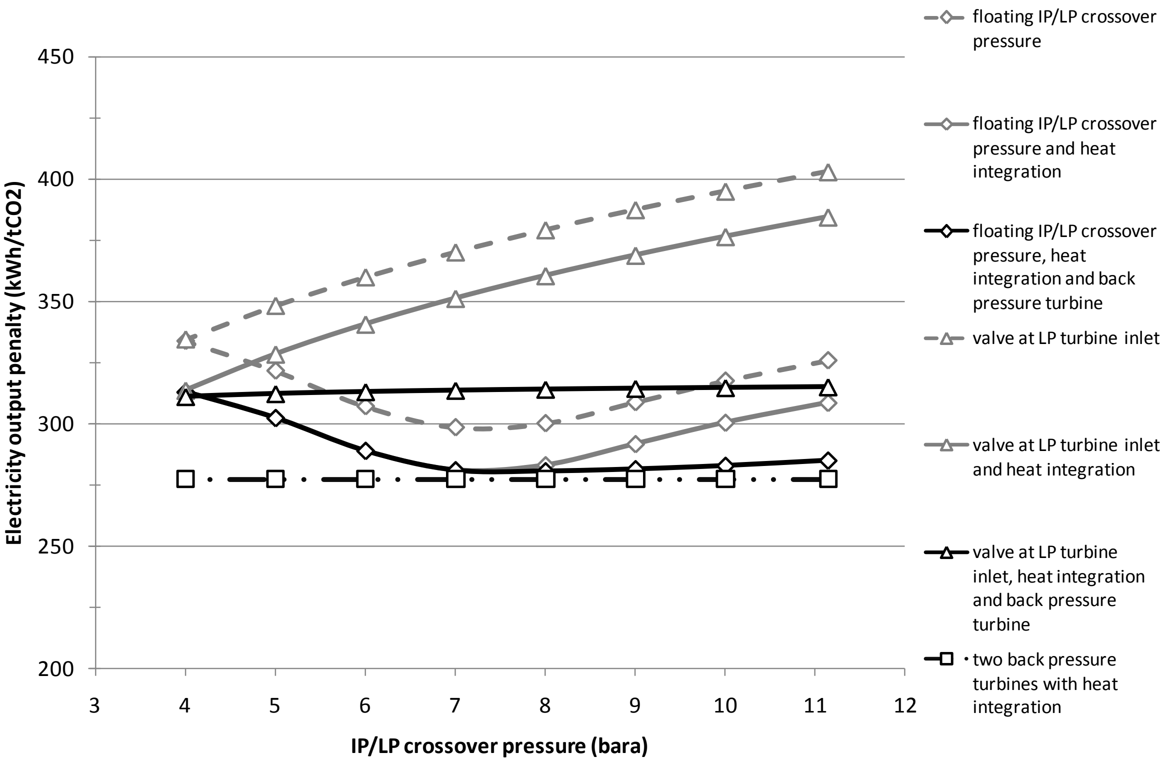

Figure A3.4 Comparison of the electricity output penalty of steam turbine retrofit options for a range of steam cycle configurations

90% capture rate – 125 kWh/tCO_2 electricity output penalty for ancillary and compression power – solvent heat of regeneration of 3.2 GJ/tCO_2 – 94% boiler thermal efficiency

Selected sites may be suitable for an effective steam turbine retrofit depending on parameters such as space, access and scope for foundations in the turbine hall or other locations (e.g. along the steam line to the reboiler) to support the additional pieces of equipment. Different site-specific parameters may, however, not be critical ‘showstoppers’, but would rather affect the technical and/or economic aspects of retrofit projects. Some of these are discussed in more detail below.

a) Sensitivity to reboiler heat transfer and steam connecting pipe pressure drop
On the steam side of the reboiler condensing steam transfers the energy for solvent regeneration. The latent heat available is a function of the steam temperature and thus of the solvent temperature once the temperature difference across the heat transfer surface of the reboiler has been taken into account. Any marginal reduction in the temperature difference across the reboiler therefore reduces the required pressure for the extracted steam to achieve a given solvent temperature, as illustrated in Figure A3.5(a). This can then lead to a related reduction in steam extraction pressure for a given PCC solvent. Any marginal reduction in the steam extraction pressure results in an increase of the power plant output and in a reduction of the electricity output penalty. Similarly, a reduction in the pressure losses of the pipe taking steam from the steam cycle to the solvent reboiler reduces the EOP. The effect of increasing the steam extraction pressure is shown in Figure A3.5(b) for the steam cycle used in this example. For the assumed pressure drop of 0.5 bar, the EOP is increased by 9 kWh/tCO_2 compared to a hypothetical case with no pressure drop. This suggests there is a case for a cost-benefit analysis of the implementation of an effective heat supply for the reboiler and a minimisation of the pressure losses across the pipe connecting the IP/LP crossover to the solvent reboiler. In the case of retrofit projects, where it may be difficult to locate the whole capture plant close to the steam turbine, the possibility of locating just the solvent stripper close to the turbine island could also be considered. Additional pumping power to circulate the solvent between the absorber and the stripper, and the cost of additional solvent inventory would have to be balanced against the extra power output (and solvent storage) obtained.

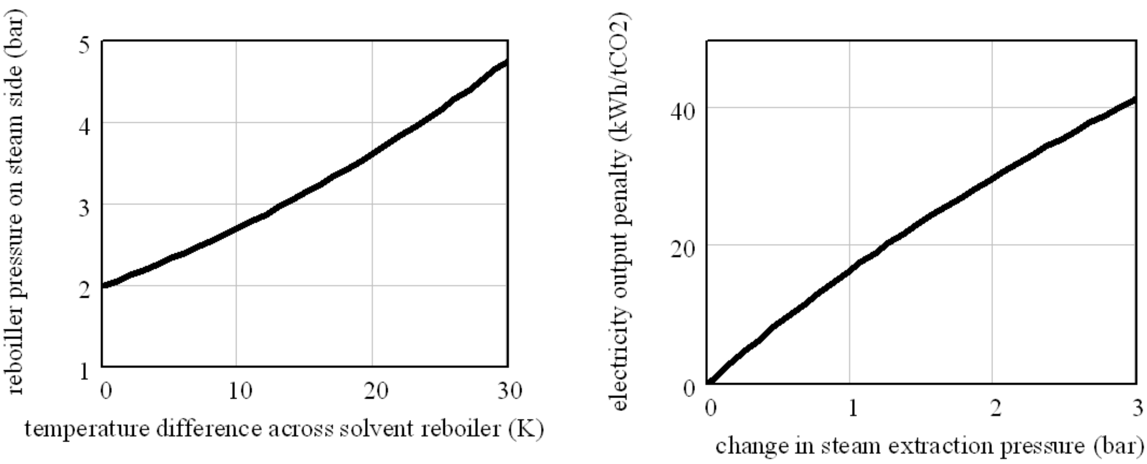

Figure A3.5: (a) left - Effect of temperature difference across solvent reboiler on steam side pressure, (b) right - Effect of steam extraction pressure on electricity output penalty

b) IP turbine considerations for floating pressure systems

In the floating IP outlet pressure system, shown in Figure A3.3, the changes in the IP turbine are:

- an increase of the end thrust for each expansion cylinder due to the change of pressure ratio across the turbine, and
- an increase of the mechanical stress on the blades.

Design strategies to mitigate the consequences of these changes are discussed below.

Changed IP turbine end thrust

For single flow IP turbines, either a stand-alone cylinder design or a combined HP-IP cylinder design, modifications to the balancing pistons could be necessary to adapt to the new operating conditions. In contrast, the end thrust on each side of double-flow IP cylinders should balance out and modifications of the balancing pistons should, therefore, not be necessary.

Mechanical strength of the IP blades

The increase in the mechanical stress on the blades of the IP turbine for the retrofit configuration shown in Figure A3.3 is illustrated in Figure. For this illustrative analysis the turbine is composed of 8 impulse stages with hypothetical turbine blades that can sustain any levels of mechanical stress (see Appendix B for further details). The changes in isentropic efficiency and stage loading, i.e. the changes in mechanical stress, are plotted for each stage following the turbine expansion. For this configuration the IP exhaust pressure is initially set to 11.1 bar and drops to 5.5 bar at 90% capture. The overall effect on the turbine efficiency is of the order of a 2 percentage point drop in cylinder isentropic efficiency, mostly due to changes occurring in the last few stages. The analysis also suggests that floating pressure systems are likely to be constrained by the mechanical stresses on the blades of the very last stage of the IP turbine.

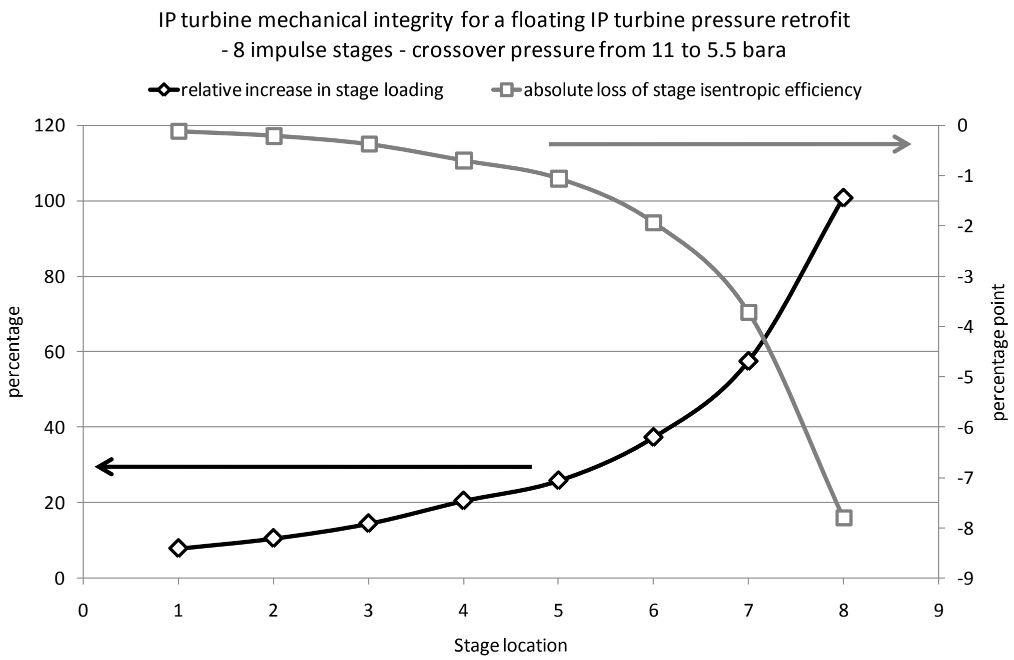

Figure A3.6: Change in isentropic efficiency and mechanical loading on each blade of an impulse IP turbine for a floating pressure with CO_2 capture

Strategies to increase the bending modulus of these blades will thus directly enhance the performance of floating pressure systems if throttling losses would otherwise be incurred. Possible strategies for specific blade design include:

- Since the bending stress on the blade is limited by the high cycle fatigue strength of the material used, which in turn is proportional to the tensile strength for common turbine materials, upgrading the alloy used in IP blades is an obvious option.
- The induced stresses could also be reduced, within the constraints of the casing and the geometry of the stator of the IP turbine, by reblading with thicker blades capable of withstanding a higher bending load but, because of the thicker aerofoil cross-section, with a small penalty in efficiency.

Illustrative reductions in the output penalty of capture achieved by increasing the mechanical strength of the last blades of the IP turbine are shown in Figure A3.7. These are contrasted with a case where an upper limit on the mechanical strength has been applied to a floating pressure system with a crossover pressure of 11.1 bar without capture. In this analysis, a constant amount of CO_2 is captured whilst a limit is set on the relative increase of mechanical stress that can be sustained by the last blade of the IP turbine. When capture is fitted, steam extraction gradually increases while IP turbine exhaust pressure falls until the limit on the blade is attained. If more steam needs to be extracted, the extraction is then controlled by throttling the LP turbine inlet until the required capture level is obtained. Without increasing the mechanical strength of the final IP stage the amount of throttling in the valve before the LP turbine is of the order of 5.4 bar. A 50% increase in mechanical strength reduces the pressure drop across the valve to 2.4 bar and reduces the electricity output penalty by 15 kWh/ tCO_2, and further by 26 kWh/ tCO_2 for a 100% increase in the allowable bending stress of the last IP turbine blades.

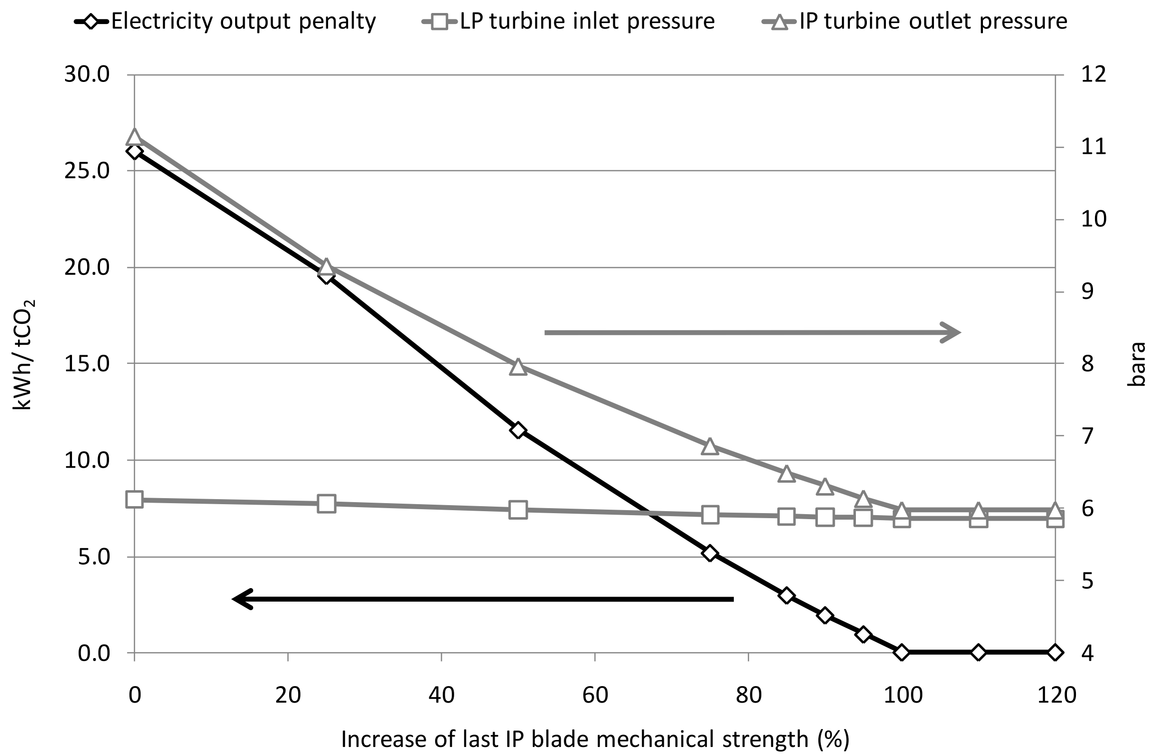

Figure A3.7: Reduction in electricity output penalty of a floating IP outlet pressure system with a reinforcement of the IP turbine last stage blades

c) Boiler feed pump turbine

Many existing steam cycles are equipped with a turbine-driven main boiler feed pump taking steam from the IP/LP crossover pipe, which requires some consideration when capture is retrofitted. In particular, a retrofit with a floating IP turbine exhaust pressure reduces the inlet pressure and thus the power output of that turbine, requiring it to be supplemented or replaced by an electric drive boiler feed pump. It is important that the boiler feed pump turbine is not removed, however, so that the plant is able to return to maximum generator output if the solvent reboiler is bypassed.

Appendix 4 Capture-ready steam turbines and capture retrofit for natural gas combined cycle plants

This Appendix is based on Lucquiaud (2010) and explores steam turbine options for NGCC (natural gas combined cycle) power plants that are retrofitted with CO_2 capture. When PCC is retrofitted to a GTCC the gas turbine can be left unchanged, as shown in Figure A4.1. It is also possible to add flue gas recirculation. This is not considered in this Appendix, but is discussed in Appendix 5.

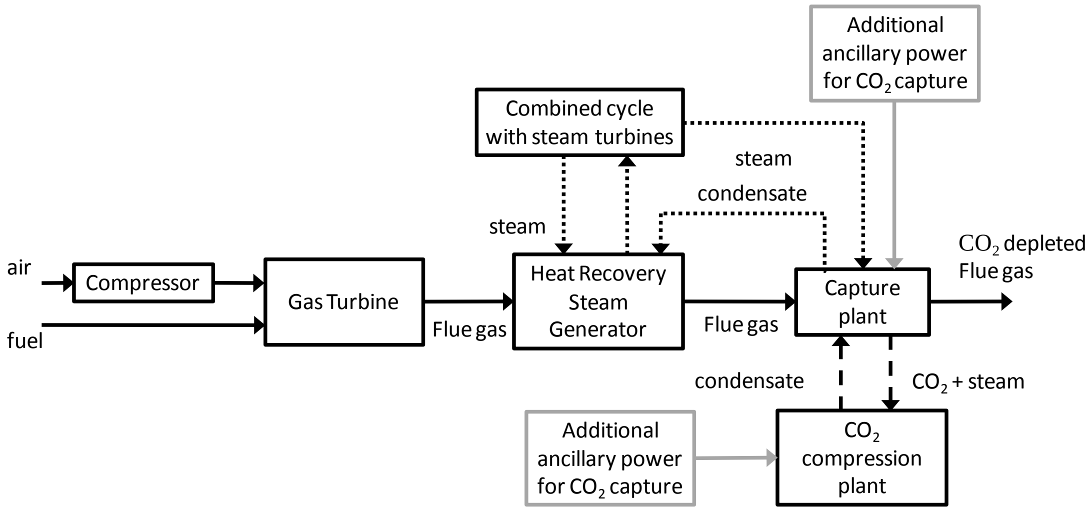

Figure A4.1 Schematic process flow diagram of a NGCC plant with PCC

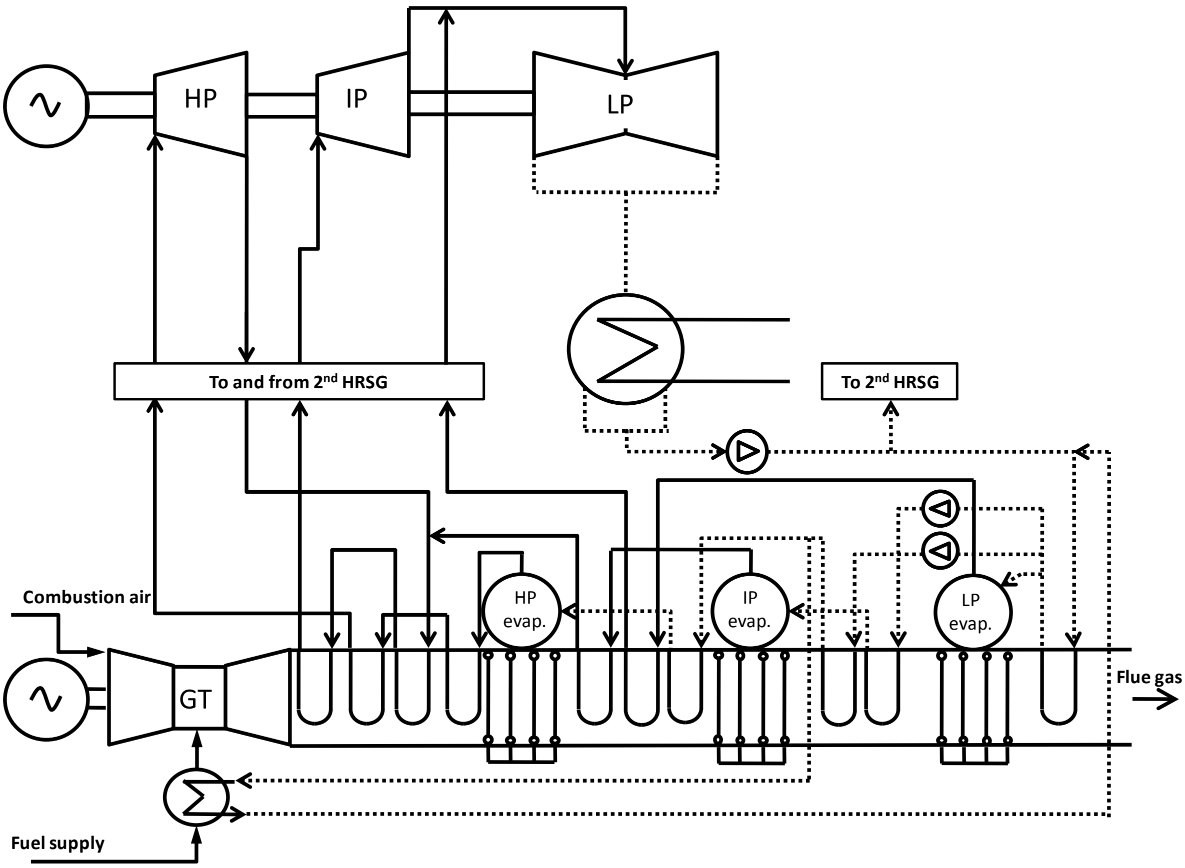

Figure A4.2 Process flow diagram of a natural gas combined cycle plant without capture, adapted from IEAGHG (2004b)

Figure A4.2 shows further details of the gas turbine, the heat recovery steam generator and the combined steam cycle of a unit without capture where the IP and LP turbines are in separate cylinders with crossover pipes (this term understood to include also possible cross-under pipes) between them. In this case the condensing steam for solvent regeneration is extracted from the IP/LP crossover and is then desuperheated using a spray with condensate from the solvent reboiler. A stand alone HP turbine with a combined IP/LP cylinder is another common design option, with consequences for future retrofits with post-combustion capture. In this latter configuration access for steam extraction from the IP/LP crossover can be challenging. An alternative retrofit approach for this case is specifically discussed below.

Several steam cycle configurations that could be used when retrofitting PCC to NGCC plants are shown in Figure A4.3 (overleaf). In this Appendix, their performance is assessed and compared to a reference plant without capture. For new-build NGCC plants with capture specific arrangements to set the value of the IP/LP crossover pressure to match the temperature of the solvent reboiler are similar to those for coal plants described in Section 3.2.3 and Appendix 3. This Appendix considers alternative retrofit options, including configurations for which the IP/LP crossover is higher than the minimum pressure necessary for solvent regeneration. It also discusses possible additional measures, which can be taken at the time of retrofit, to guarantee effective thermodynamic integration with capture. To avoid confusion it should be noted that, amongst the retrofit options shown in Figure A4.3, some of these retrofit options are worth pursuing (options (a), (b) and (c)). By contrast, options (d) and (e) are proposed for illustrative purposes in order to highlight the consequences of poor thermodynamic integration with capture. Each of these options will now be introduced in more detail.

a) Replacement of the LP turbine cylinder

The existing LP steam turbine is replaced by a new LP turbine cylinder when capture is retrofitted, as shown in Figure A4.4. The design steam flow for the new turbine exactly matches the flow available once steam has been extracted for the CO_2 capture system. This option involves additional capital costs compared to a standard retrofit, but gives the option to retrofit the plant with a system that is similar in performance to a new-build NGCC power plant with PCC. The capital cost implications of replacing a cylinder are important and would not necessarily be commercially justified. This option can, however, be seen as a reference case with capture for retrofit options in terms of performance with capture. It is also likely to be a worst case scenario for operating and upgrading flexibility since the LP turbine is sized for capture operation only.

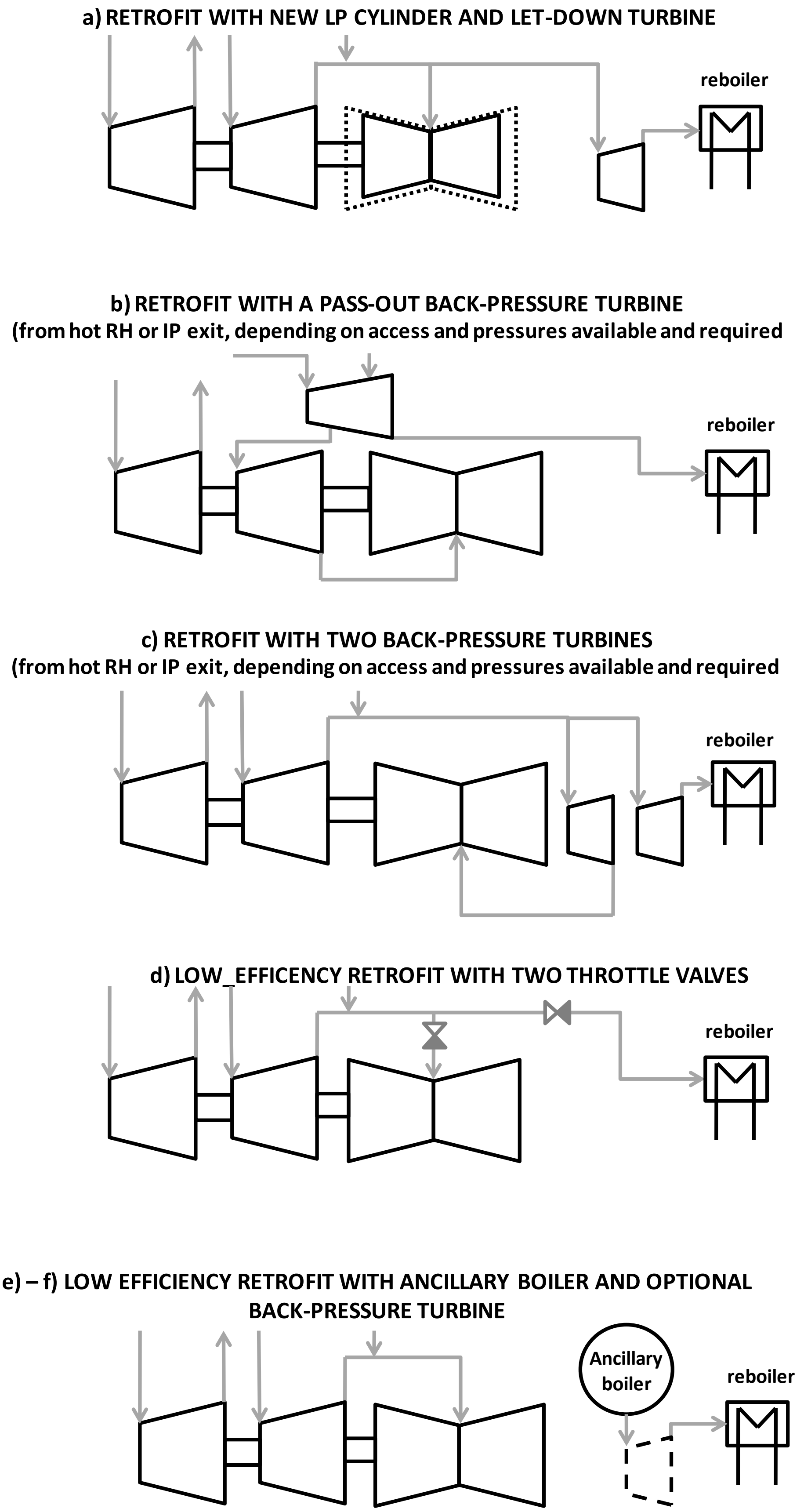

Figure A4.3 Retrofit options for natural gas combined-cycle plants (generator not shown)

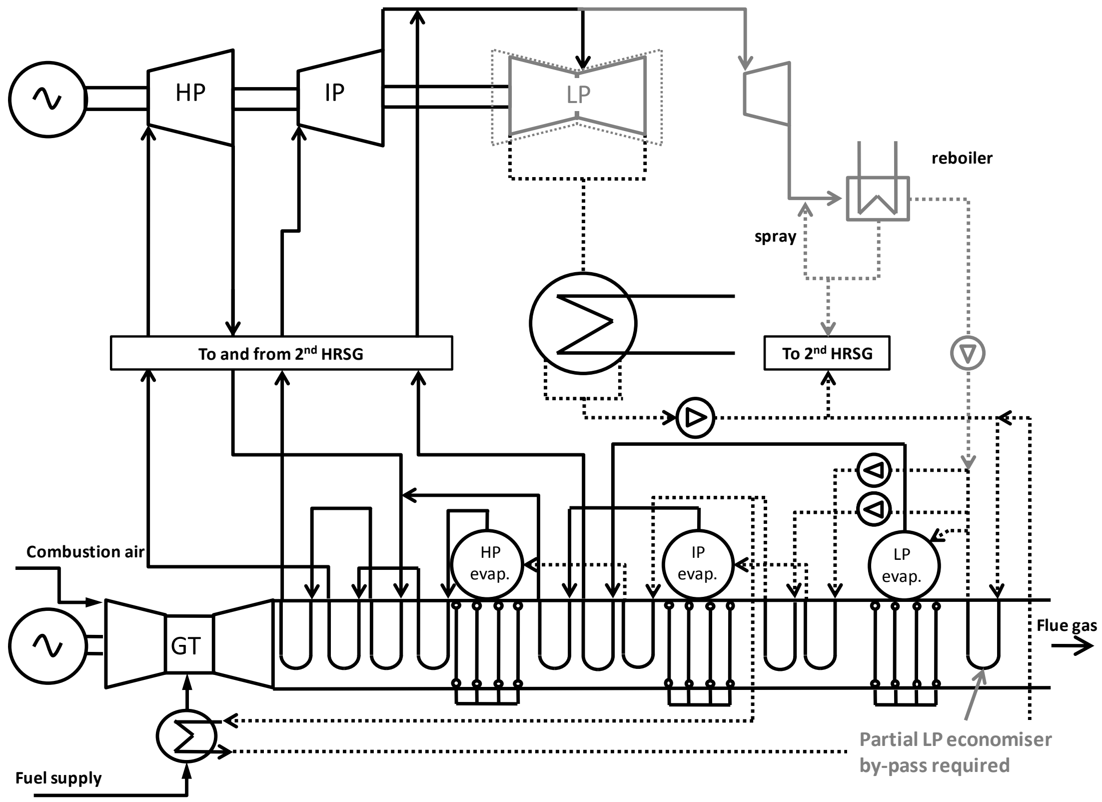

Figure A4.4 Retrofit of a natural gas combined cycle plant by replacing the low pressure turbine and the addition of a back-pressure turbine in the solvent extraction line

b) Pass-out back-pressure turbine from reheater outlet

Access for steam extraction at the LP inlet may prove to be difficult for configurations with a combined IP/LP cylinder and hence no IP/LP crossover. In this case the only access point for large amounts of extraction is at the reheater outlet[24], for steam at a higher pressure and temperatures. Space needs to be provided to do this, with a spool piece at the front of the IP turbine. The pressure and temperature conditions are obviously unsuitable for use directly for solvent regeneration. Additionally, both the IP and LP turbines will be operating at reduced flow when steam is extracted for use in the PCC unit, which modifies the pressure ratio across the IP and LP turbine and decreases their absolute pressures. This modifies the blade velocity triangles and reduces the overall turbine efficiency (see Lucquiaud, 2010 for further details). To match steam conditions to the IP/LP cylinder and the capture plant a tailored design pass-out back pressure turbine comprising two distinct groups of blades could be fitted, as shown in Figure A4.5. It takes the entire mass flow of steam at the reheater outlet and expands it down to the new reduced IP turbine inlet pressure. The required amount of steam for capture is expanded in the second group of blades of the additional turbine, while the remaining flow is expanded across the IP and LP turbine. A third group of blades gives the option of keeping the LP superheater operating when capture is fitted. This would avoid the losses that would occur if the steam available at the LP superheater outlet had to be throttled down to the new LP turbine inlet pressure. Instead the steam available expands, from the LP superheater pressure down to the reboiler pressure in the last stages of the pass-out back-pressure turbine and generates power. Provisions for

[24] Space for steam extraction is also available at the reheater inlet, but would affect heat transfer downstream in the flue gas path and would necessitate costly modifications of the HRSG too.

steam extraction, reinforcement of foundations and space for the additional turbine (and generator, if not clutched to the main generator) should be considered if a new plant is being built to be CCR and will also need to be addressed for any existing plant where this retrofit option is considered.

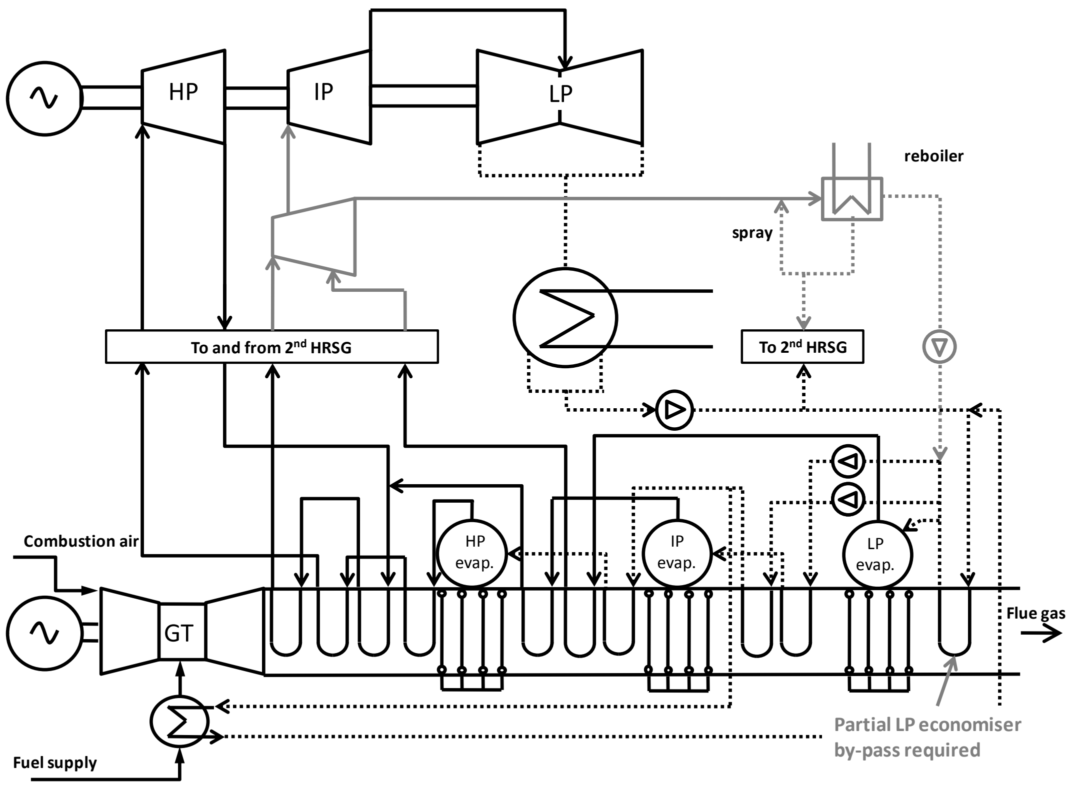

Figure A4.5 Retrofit of a natural gas combined cycle plant with the addition of a tailored design pass-out back-pressure turbine at the reheater outlet

c) Retrofit with two back-pressure turbines

This option, shown in Figure A4.6, also has the advantage that performance with capture is independent from the IP/LP crossover pressure, provided that the pressure is set above future expected requirements for solvent regeneration. A back-pressure turbine is fitted in the steam extraction line to generate power while reducing the steam pressure to the desired value in the reboiler. A second back-pressure turbine is fitted before the steam enters the LP turbine. This produces additional power and avoids throttling. The principal additional items that should be taken into account when this option is considered in CCR design are providing space and reinforcing the foundations of the turbine hall at the expected locations of the back-pressure turbines (and their dedicated generator if required, or provide provision for connection via a clutch) and a spool piece in the IP/LP crossover for a tee to facilitate steam extraction.

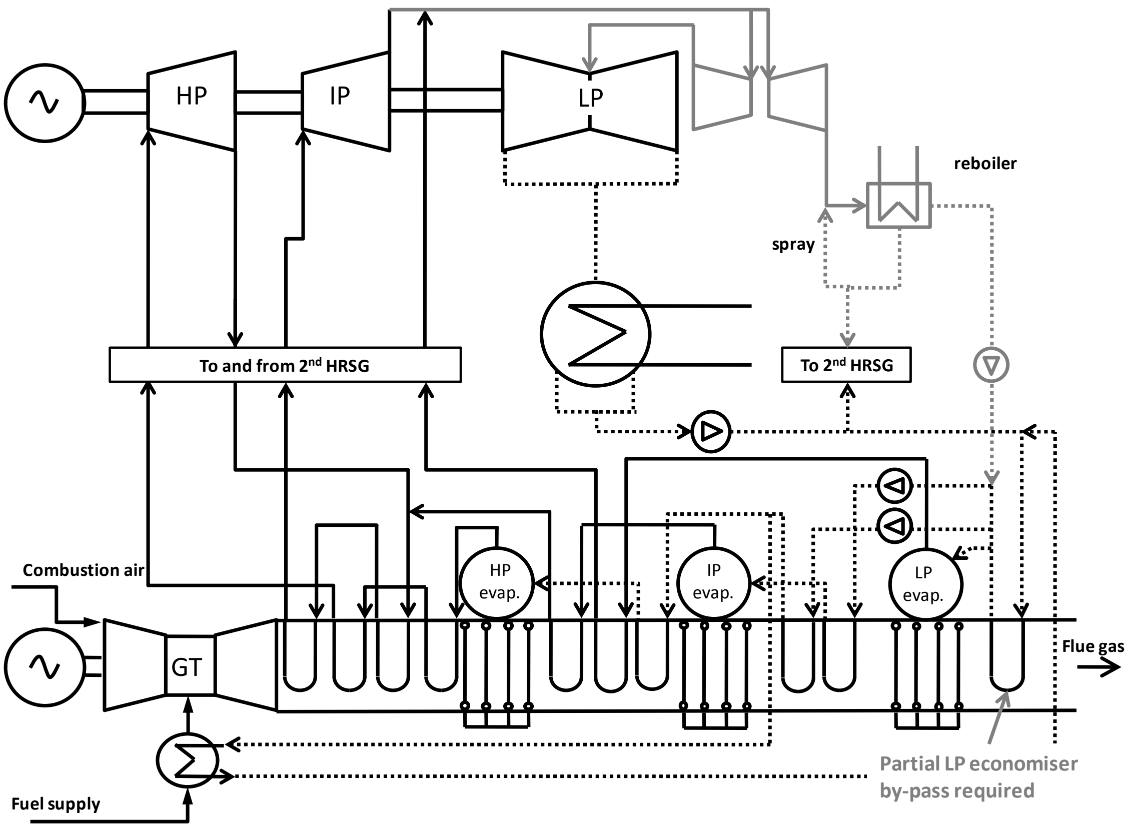

Figure A4.6 Retrofit of a natural gas combined cycle plant with the addition of two back-pressure turbines

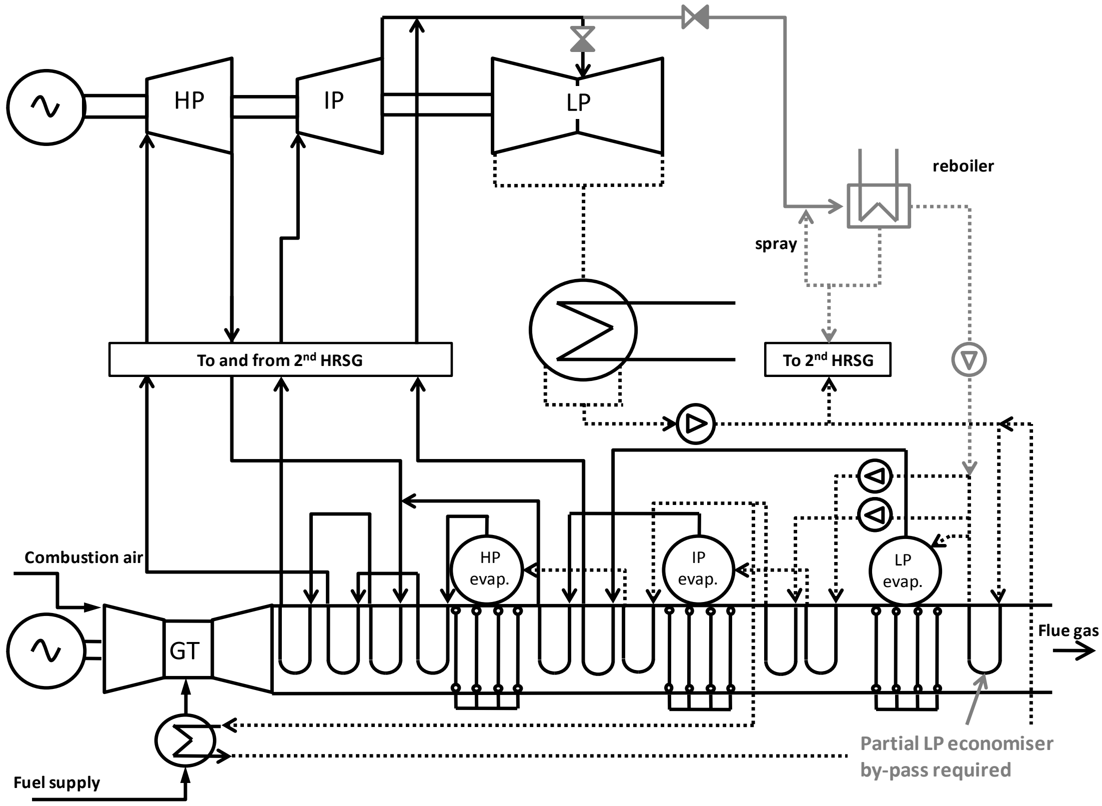

Figure A4.7 Low efficiency retrofit of a natural gas combined cycle plant with two throttling valves

d) Low efficiency retrofit with two throttle valves
In this retrofit option the LP turbine is left unchanged. Consequently the reduced steam flow through the LP turbine results in a lower inlet pressure. To maintain the design exit pressures for the IP turbine and the LP evaporator pressure it is necessary to throttle the LP inlet downstream of the extraction point, e.g. using the butterfly valve shown in Figure A4.7. A second valve is added in the solvent extraction line to expand the steam down to the pressure corresponding to the desired reboiler saturation temperature, once pressure drops and temperature difference in the reboiler have been taken into account. The principal additional items for CCR consideration are a spool piece in the IP/LP crossover for a tee and the throttling valves. The performance when CO_2 capture is retrofitted is poor due to the losses occurring through the two valves.

e) Low efficiency retrofit with a separate ancillary boiler
This option leaves the steam turbines unchanged and instead uses a separate ancillary boiler to provide the heat necessary for solvent regeneration. It has been considered in several studies (e.g. Canadian Clean Power Coalition work discussed in Box 2.1 in Chapter 2) since it does not require any modifications to the steam turbines and retains most of the electrical output from the plant (only the additional ancillary power required by the CO_2 capture unit is lost). The most obvious drawback of using a separate boiler to provide the energy for solvent regeneration is straightforward to identify. Significant efforts have been made to improve the efficiency of NGCC plants up to around 55-60% LHV because it makes economic sense to do so. The calorific value of natural gas is used at very high temperatures in the gas turbine, then high pressure, high temperature steam is raised from the gas turbine exhaust. Most of the energy coming from the fuel is used and low grade heat is rejected in the gas turbine exhaust at around 80-100ºC and in the steam cycle condenser at around 30ºC. Providing energy for solvent regeneration by extracting low pressure steam from the turbines repeats the above, only differing in the temperature of condensation. The steam required for capture is condensed in the solvent reboiler at 100ºC to perhaps 150ºC depending on the solvent used. In contrast, separate ancillary boilers do not make use of the full potential of the fuel calorific value. They turn the energy in the gas to heat at this same low reboiler temperature, missing out all the opportunity to extract higher-grade electrical energy.

f) Retrofit with a separate ancillary boiler – and an optional back-pressure turbine
With a separate ancillary boiler the generator rated capacity constrains the amount of power that can be exported to the electricity network. The net power output of the plant is, however, still reduced. As noted above, additional ancillary power has to be provided for the capture plant and for CO_2 compression. If the boiler is used to generate superheated steam at a higher pressure, which is then expanded through a back-pressure turbine upstream of the reboiler, additional power is available for ancillary consumption. The plant then operates with the same net output to the grid before and after capture is fitted. This option, shown in Figure A4.8, still extracts less electrical energy per unit of gas than feasible in a gas turbine attached to a combined cycle and suffers from an additional electricity efficiency penalty compared to steam turbine retrofits.

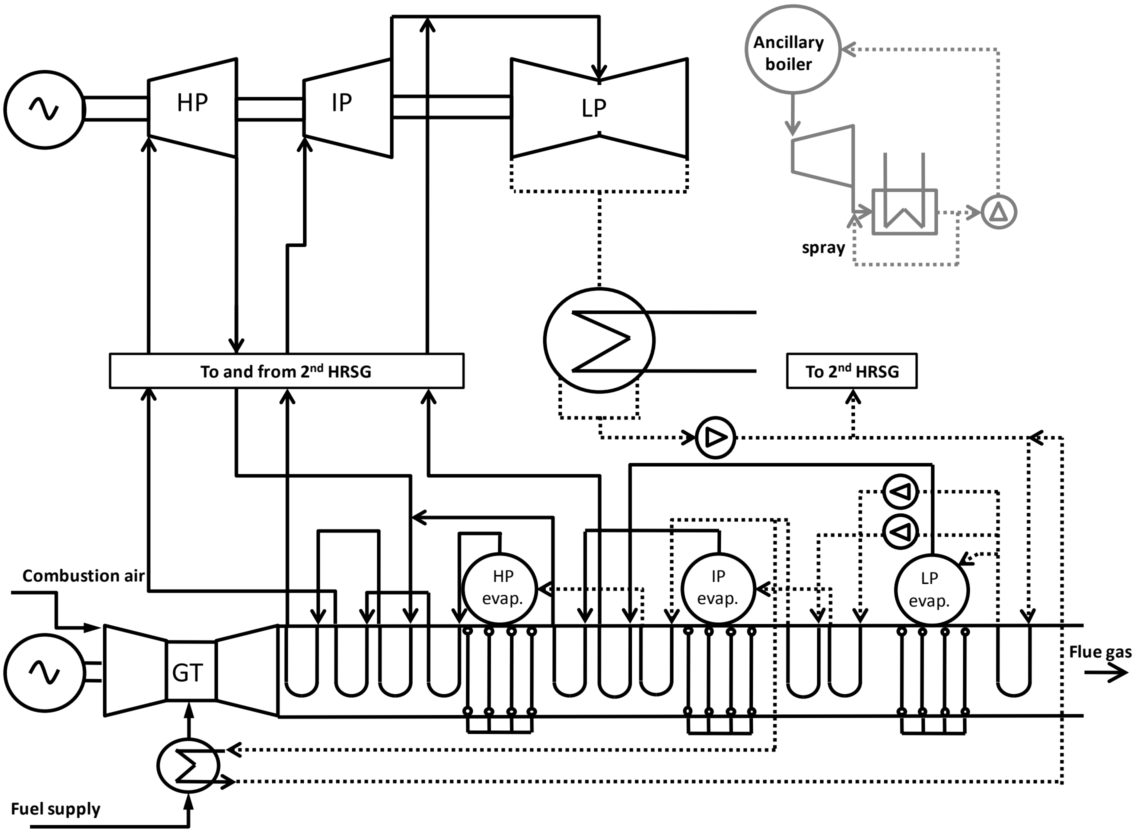

Figure A4.8 Retrofit of a natural gas combined cycle plant with a low efficiency separate ancillary boiler and back-pressure turbine system

g) Floating IP/LP crossover pressure

Another retrofit option similar to the floating pressure system proposed for CCR steam turbines has been investigated. It has not been considered further in this analysis, however, since a change in pressure at the IP/LP crossover would affect the heat transfer regime of several heat exchangers in the HRSG – the LP economizer, the LP evaporator, the IP economizer, and the HP economizer. This would require an intensive additional investment as a CCR pre-investment. It is, therefore, been ruled out for further analysis but could be considered for units that operate with capture from the outset.

The systems outlined above have been modelled following the natural gas plant cases of the same IEAGHG study (IEAGHG, 2004b) as was used in Appendix 3, with the ancillary power for CO_2 capture and compression based on the Fluor Econoamine FG Plus case. Given the date of this reference this is, however, expected to be a 'worst case' compared to best available technology at the time of writing and beyond. There is, therefore, an expectation that this is a maximum value for a range of possible future steam extraction rates. Two type GE9351 FA gas turbines with a gross output of 260MW$_e$ each are followed by two HRSG units and a single steam turbine set. The steam cycle is a sub-critical (125/27/5.3 bar) triple pressure reheat cycle. The IP steam is superheated up to the maximum superheat temperature possible (560 ºC) by an additional tube bundle located in the gas path in parallel with the high pressure (HP) superheater.

When CO_2 capture is retrofitted to the plant, the gas turbine performance remains unaffected, since there is no direct connection between the gas turbines and the capture plant[25]. The scope of modelling work has, therefore, been limited to the CCR features of the HRSG and the steam cycle. Mass flows and heat exchanger duties in the HRSG remain approximately unchanged except for the LP economizer duty, which is reduced due to the lower LP turbine mass flow (see Lucquiaud (2010) for additional details of turbine modelling methods). It is assumed that additional cooling water is available for the requirements of capture and compression and that the condenser pressure drops when the mass flow of steam is reduced.

Table A4.1 Performance of capture-ready steam turbine options for NGCC plants

	Base case no capture	LP turbine replacement	Two back pressure turbine retrofit	Pass-out turbine retrofit
Performance without capture				
Gas input (MW_{th})	1396.0	1396.0	1396.0	1396.0
Net power output (MW_e)	773.6	773.6	773.6	773.6
Efficiency (% LHV)	55.4	55.4	55.4	55.4
Performance with capture				
Gas input (MW_{th})	1396.0	1396.0	1396.0	1396.0
Gas turbine gross output (MW_e)	520	520	520	520
Steam cycle gross output (MW_e)	277.6	230.9	230.4	230.0
Gross power output (MW_e)	797.6	750.9	750.4	750.0
Ancillary power (MW_e)	24.0	78.0	78.0	78.0
Net power output with capture (MW_e)	773.6	672.9	672.4	672.0
Efficiency with capture (% LHV)	55.4	48.2	48.2	48.1
CO_2 emissions				
CO_2 emissions (kg/s)	81.7	12.3	12.3	12.3
CO_2 emissions (g/kWh)	368.7	58.8	58.8	58.8
CO_2 Capture rate	0.00	0.85	0.85	0.85
Performance metrics				
Gas usage per tonne abated (MWh_{th}/tCO_2)	0	0.87	0.88	0.88
Electricity output penalty (kWh/tCO_2)	0	403.1	405.0	406.6

[25] The provision of a flue gas blower to overcome the absorber pressure drop ensures that the gas turbine back pressure is not modified when capture is added and that its output is not modified.

Table A4.2 Performance of low-efficiency NGCC retrofit options

	Two valve retrofit	Ancillary boiler	Ancillary boiler and turbine
Performance without capture			
Gas input (MW_{th})	1396.0	1396.0	1396.0
Net power output (Mw_e)	773.6	773.6	773.6
Efficiency (% LHV)	55.4	55.4	55.4
Performance with capture			
Gas input (MW_{th})	1396.0	1660.3	1750.0
Gas turbine gross output (MW_e)	520	520	520
Steam cycle gross output (MW_e)	217.1	277.6	351.4
Gross power output (MW_e)	737.1	797.6	871.4
Ancillary power (MW_e)	78.0	92.8	97.8
Net power output (Mw_e)	659.1	704.9	773.6
Efficiency (% LHV)	47.2	42.5	44.2
CO_2 emissions			
CO_2 emissions (kg/s)	12.3	14.6	15.4
CO_2 emissions (g/kWh)	59.8	65.8	63.5
CO_2 Capture rate	0.85	0.85	0.85
Performance metrics			
Gas usage per tonne abated (MWh_{th}/tCO_2)	1.01	1.82	1.50
Equivalent electricity output penalty (kWh/tCO_2)	458.0	890.7	822.0

The performance of the retrofit configurations is shown in Tables A4.1 and A4.2. Additional details are given in (Lucquiaud, 2010). The first three retrofit options achieve similar performance with capture, around 48.2% LHV, with an electricity output penalty of around 400-405 kWh/tCO_2 (Table A4.1). The retrofit option where the LP turbine is replaced has a similar configuration to a new-build unit not designed for flexible operation. Performance is slightly improved compared to a new-build plant with capture and the same steam conditions due favourable condenser pressures when LP steam flows are reduced. A small reduction of power output, 0.5MW, is observed for the retrofit with two back-pressure turbines taking steam at the IP/LP crossover. Additional power generated through the reduction of the condenser pressure compensates for the reduction in the LP turbine isentropic efficiency – of the order of 1.5-2 percentage points - due to the change of pressure ratio.

The pass-out back-pressure turbine retrofit reduces power output further, by approximately 0.9MW, compared to the LP replacement option. Since almost half of the initial IP turbine inlet mass flow now expands in the second group of stages of the pass-out turbine, the IP turbine inlet pressure drops from 27 bar to 13.6 bar. As a result, both the IP and the LP pressure turbine operate in a mode equivalent to sliding pressure operation, i.e. at reduced flow and a similar pressure ratio. The IP turbine efficiency is not affected by the change of operating conditions. Like the previous option, the LP turbine isentropic efficiency reduces by 1.5-2 percentage points, since expansion in the last stages is ‘forced’ by the outlet pressure.

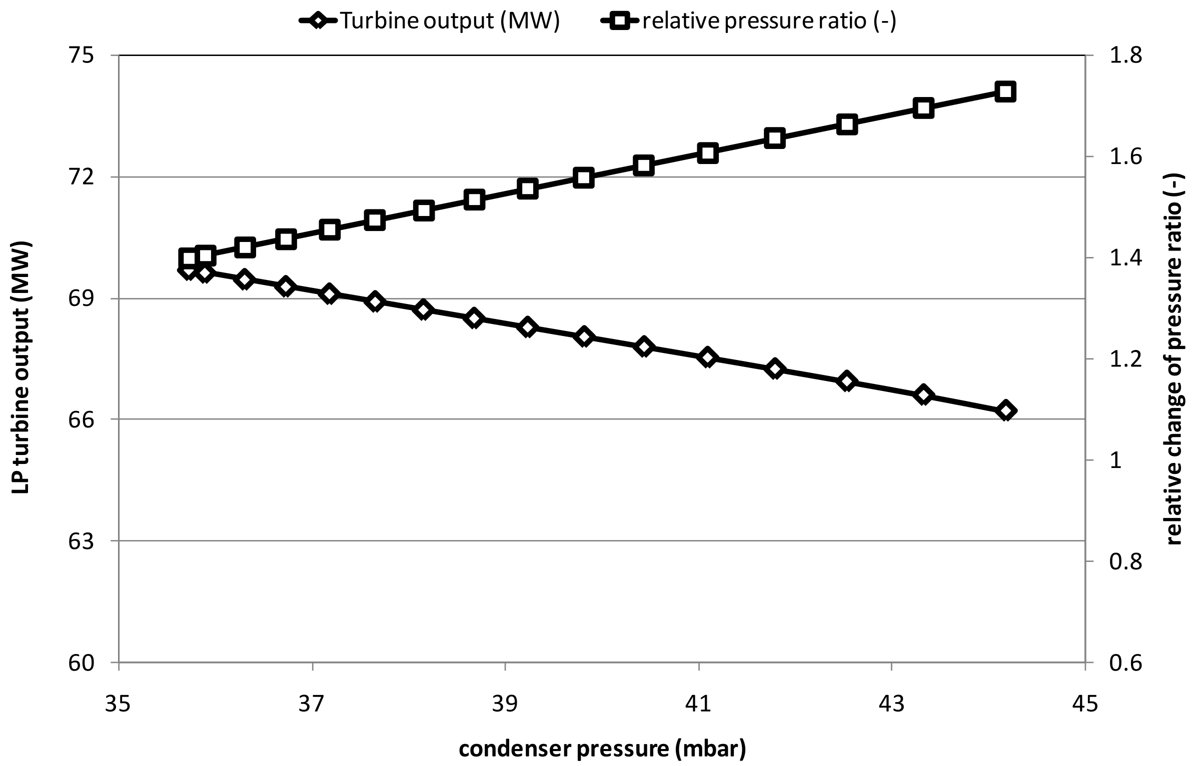

Figure A4.9 Variations of LP turbine output with the condenser pressure of a two back-pressure turbine retrofit

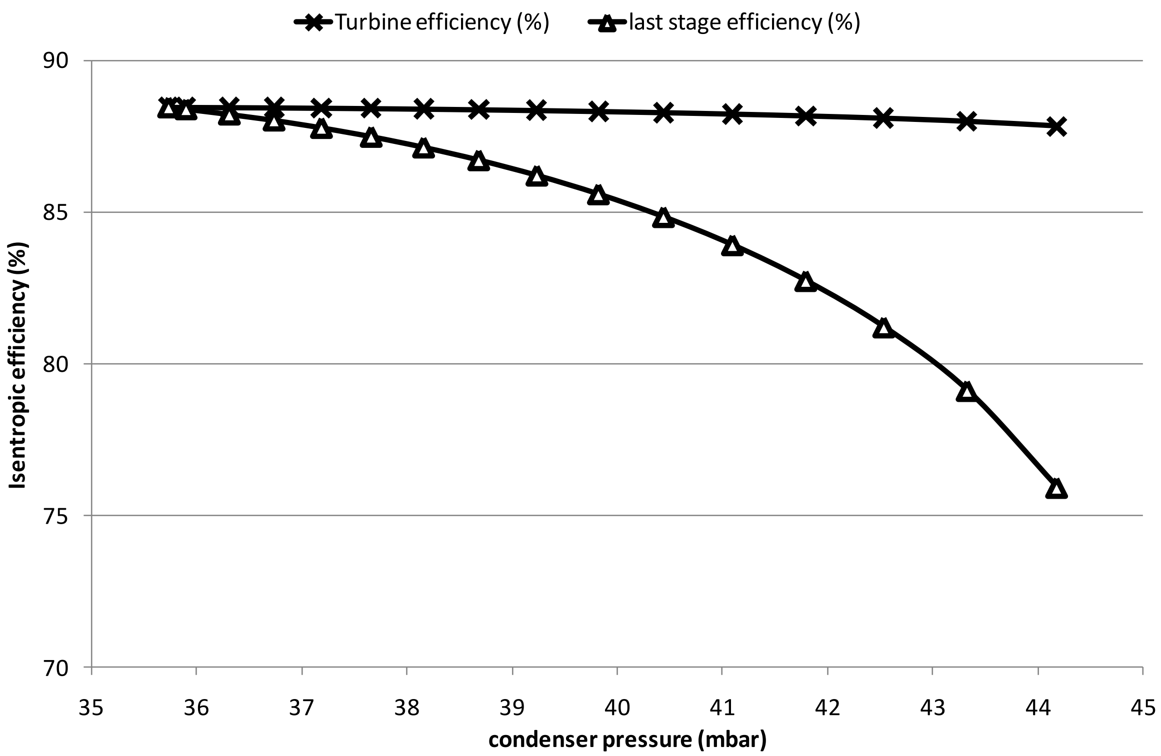

Figure A4.10 Variations of the LP turbine efficiency with condenser pressure of a two back pressure turbine retrofit

The lower condenser pressure compensates for the additional losses to some extent because there is a second positive feedback in lowering the condenser pressure. The LP turbine operates closer to its initial pressure ratio and helps to maintain a velocity triangle close to design conditions in the last stages and therefore the stage isentropic efficiency. This effect is illustrated in Figure A4.9 for the retrofit with two back-pressure turbines, where the LP turbine output and the relative change of pressure ratio across the turbine are plotted as a function of the turbine outlet pressure. It shows that there is an almost linear relationship between the turbine pressure ratio and the turbine output.

Variations in the LP turbine isentropic efficiency, and, in particular, the stage efficiency for the last row of blades, indicated in Figure A4.10, show that the last stage of the turbine in particular is affected by the outlet pressure. For these three options part of the LP economizer has to be bypassed to avoid ‘steaming’ when capture is added. The inclusion of an LP economizer gas bypass (or economiser section isolation) to accommodate the reduced duty is also a possible CCR feature and should avoid time-consuming modifications to, or replacement of, the LP economizer.

The retrofit with two valves, which is one of the low efficiency retrofit options included in Table A4.2, inevitably suffers from high throttling losses. These account for a 1% point reduction in LHV efficiency, which is an additional electricity output penalty of 55 kWh/tCO_2. The two other retrofit options in Table A4.2 use a separate ancillary boiler and leave the steam cycle unchanged. They both lead, however, to increased gas consumption. For the purpose of comparison alternative performance metrics are introduced below.

First, the gas usage per tonne of CO_2 abated is a useful metric to quantify the additional gas consumption of the separate ancillary boiler options over the CO_2 abatement associated with that option. It is defined as the difference between the gas consumption per unit of electricity with and without CCS, over the difference in specific CO_2 emissions, as in equation A4.1. The gas usage of the separate ancillary boiler retrofit option increases to 1.82 MWh_{th}/tCO_2 abated. When a back pressure turbine is added to generate power from the steam raised in the additional boiler it still increases but only to 1.50 MWh_{th}/tCO_2 abated. This is still somewhat higher than 0.87-0.88 MWh_{th}/tCO_2 for the three retrofit options considered in Table A4.1.

$$\frac{\mathrm{MW_{th}/MW_e\ with\ CCS} - \mathrm{MW_{th}/MW_e\ without\ CCS}}{\mathrm{kg\ CO_2\ /MWh_e\ without\ \ CCS} - \mathrm{kg\ CO_2\ /MWh_e\ withCCS}} \qquad \text{(A4.1)}$$

A second useful performance metric is the equivalent electricity output penalty, defined as the difference in power output if the same amount of gas were burnt in a reference plant without capture, over the difference in CO_2 emissions:

$$\mathbf{EOP_{eq}} = \frac{Q_B^R * \eta - W}{E - E^R} \qquad \text{(A4.2)}$$

$\mathrm{EOP_{eq}}$	kWh/tCO_2	Equivalent electricity output penalty of capture and compression
Q_B^R	MW_{th}	Gas input with capture
η	-	LHV efficiency of NGCC plant without capture
W	MW_e	Net power output of NGCC plant without capture
E	kg/s	CO_2 emissions without capture
E^R	kg/s	CO_2 emissions with capture

The equivalent electricity output penalty more than doubles to 890.7 kWh/tCO_2 with the separate ancillary boiler alone, compared to 403 kWh/tCO_2 for the CCR options considered in Table A4.1. The addition of a back-pressure turbine generates additional power, which matches the additional ancillary power requirement, and slightly reduces the electricity output penalty to 822 kWh/tCO_2. This clearly shows that retrofitting a separate ancillary boiler to a NGCC plant is, not only, not as thermally efficient as an integrated retrofit extracting steam from the combined cycle for solvent regeneration, but is also likely to increase the impact of natural gas price volatility on future costs of generation.

As already noted, it is expected that operation at full load without capture for a retrofit where the LP turbine is replaced will be challenging since the new LP turbine cannot accept any additional steam flow that would be available at the IP/LP crossover pressure when the capture system is not operating. Alternatives might be for the gas turbine to be operated a part load or, if an HRSG bypass damper was installed, it might be possible to reduce steam evaporation rates accordingly. For options (b) and (c) in Figure A4.3, the additional back-pressure turbine can simply be by-passed to return to operation with capture.

Appendix 5 Flue gas recycling in semi-closed gas turbines with CCS: potential for retrofitting to existing NGCC power stations – a literature review

It can be shown by simple analysis that the minimum work input to separate CO_2 from flue gas, w_{min}, is determined by the initial and final mole fractions of CO_2 in the flue gas alone (e.g. McGlashan and Marquis, 2007). This means that progressively more energy is required to extract CO_2 from flue gas as the latter becomes leaner in CO_2[26]. In practice, due to irreversibilities inherent to CO_2 removal processes, the work input in to real world plant will be significantly higher than w_{min}. When chemical scrubbing is used in a PCC process the choice of solvent is affected by the initial flue gas CO_2 concentration. This is because to scrub lean flue gas, the required thermodynamic driving force is greater than for CO_2 rich gas. The CO_2 must, therefore, undergo a larger drop in chemical potential in the scrubbing tower and, as a consequence, there is more lost work associated with scrubbing lean gases. Hence, flue gas rich in CO_2 can be scrubbed with much less 'aggressive' solvents.

In this context, any method capable of increasing the concentration of CO_2 in the flue gas above a certain level is a candidate for reducing the energy penalty of PCC. This survey in this Appendix explores one technique able to achieve this goal: the semi-closed gas turbine (SCGT). This work will not examine the limits of SCGTs as they might be applied to new build plant. Instead the potential for retrofitting SCGTs to pre-existing natural gas, combined cycle (NGCC) power stations are reviewed.

a) SCGT background

The semi-closed cycle is a cross between a closed and an open Joule cycle (Horlock, 2003). In a SCGT, a fraction of the turbine exhaust is first cooled; separated from condensed water in a separator; and then recirculated back to the inlet of the compressor – so-called exhaust gas recirculation (EGR). The recycled flue gas replaces part of the excess air normally ingested by gas turbines. Amongst other effects this diluent gas caps the combustor exit temperature at an acceptable level. In the limit, the amount of EGR can be increased until only the stoichiometric amount of air is ingested by the engine. Figure A5.1 shows an illustration of a typical scheme (overleaf, from Facchini et al, 1997).

The SCGT cycle dates from the 1940s (Anxionnaz, 1948). Lear and Laganelli (2001) reviewed much of the early work on SCGT and cite a number of hard to find references from the 1940s through to the 1960s (Baumeister et al, 1946; DeWitt et al, 1956; Gasparovic, 1968). The paper stated that the earliest practical incarnations of SCGT's were completed by two groups; commercially by Sulzer Brothers (Baumeister et al, 1946) and also for the US Navy as part of the Wolverine research program (DeWitt et al, 1956). Both of these programs examined SCGT cycles due to their potential for improving cycle performance and particularly specific work output. EGR results in an increase in the molar and hence volumetric specific heat of the gas flowing through an engine. Since turbomachinery is fundamentally limited by the volumetric flow, SCGT's are a viable way of increasing power output, although the engine pressure ratio must rise for a given turbine temperature ratio. Although this work was abandoned in the late 1960s, in the 1990s NASA re-examined SCGT's and conducted a research program involving the testing of a small scale SCGT (Lear and Laganelli, 2001; MacFarlane and Lear, 1997).

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[26] A further work input is required to perform the compression and purification of the CO_2 once it has been extracted from the flue gas, but this aspect will not be considered here.

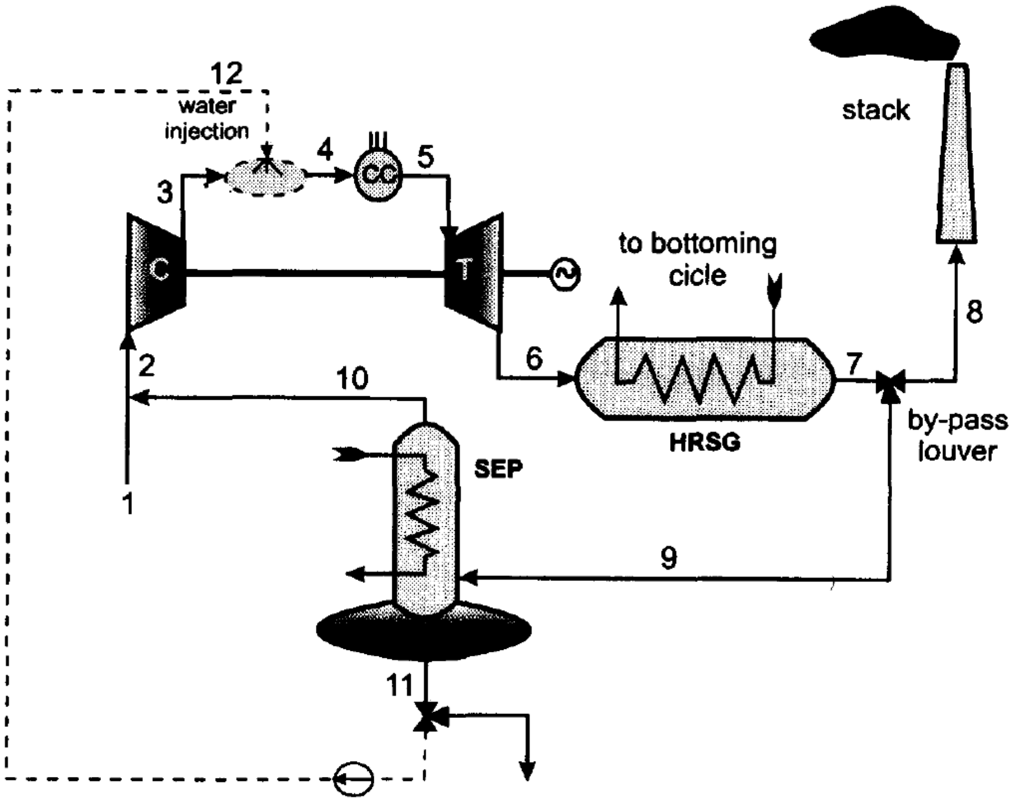

Figure A5.1 Diagram of semi-closed cycle (Facchini et al, 1997)

A number of groups have looked at SCGT's as a potential NOx reduction technology (Facchini et al, 1997; Lear and Laganelli, 2001; Lazi et al, 2005; Muley and Lear, 2003). This reduction in NOx generation is due to the lower O_2 concentration and the increased heat capacity of the compressor exit stream, leading to a reduction in flame temperature. Using the Zeldovich mechanism, in a stirred reactor model, Muley and Lear were able to show the effect of EGR on thermal NOx generation. They concluded that an order of magnitude reduction in NOx emissions was possible with high levels of EGR.

A further advantage of SCGT's is the potential for 'water harvesting'. Because, the flue gas must be cooled prior to its return to the compressor, much of the water of combustion will be condensed in the heat exchanger at this point. Khan et al (2008) showed that the quantity of water is not insignificant, especially if a high hydrogen content fuel like natural gas is being used in the engine. The water harvested in this way is probably insufficiently pure for use as a municipal potable supply, although a study commissioned by the US army examined the potential for supplying potable water to troops (Lear et al, 2004). Nonetheless, even in an industrial application, the water, after polishing, can easily be used as boiler feed or for other uses in and around the power station (MacFarlane and Lear, 1997).

Many authors have looked at semi-closing as part of a carbon capture scheme. Most of the papers deal with novel cycles such as the Graz (Jericha and Fesharaki, 1995) and Matiant (Mathieu and Nihart, 1999) cycles which are oxy-fuel cycles and hence outside the scope of this Appendix. Kvamsdal et al. (2007) review and compare a number of SCGT cycles, all of which would require major modification to an existing plant before implementation was possible. Variations include the use of a SCGT combined with:

- recuperation (Bolland and Stadaas, 1995);
- intercooling and aftercooling of the compressor (Manfrida, 1999);
- CO_2 removal at high pressure after partial compression in the main gas turbine's compressor (Finkenrath et al, 2007);
- water injection between compressor and combustor using water harvested from the cycle (Fiaschi and Manfrida, 1998) ; and
- a reformer to convert CH_4 and H_2O, from the separator, into CO and H_2 prior to combustion of the mixture in the combustor (Fiaschi and Baldini, 2009; Fiaschi et al, 2004).

b) Specific research on retrofitting SCGT cycles to NGCC power stations
Facchini et al (1997) is perhaps the earliest work on retrofitting of SCGT cycles. They noted that "the cycle optimization parameters (β, pH) and the basic thermofluid-dynamics indicators are not much different from those of open-cycle gas turbines. This means that existing equipment could be used or adapted". In this case β refers to the gas turbine's pressure ratio and pH to the peak cycle pressure of the bottoming steam cycle.

In the Facchini et al (1997) study, the authors looked at semi-closing of existing combined cycle power stations. They showed a small increase in cycle efficiency and power output. They also looked at practical issues and argued that, although the composition of the working fluid in the gas turbine changes markedly, as far as turbomachinery design was concerned, the principle non-dimensional groups are relatively unaffected. Hence, retrofitting is possible with some slight scaling of flow rates but critically using the existing compressor and turbine. Facchini et al (1997) went on to examine the potential of SCGTs from an environmental point of view and identified the two key changes: a reduced flue gas flow rate and higher CO_2 concentration in those gases passed to the PCC unit.

Bolland and Mathieu (1998) examined the retrofitting of a SCGT cycle to a large frame, General Electric, GE - 9FA gas turbine, with a triple pressure bottoming steam cycle achieving a thermal efficiency of 55.3%. In the paper, a recirculation ratio, R, was defined as the fraction of the exhaust gas (after condensation of water) recycled back to the compressor inlet (assumed to be on a mass basis), thus:

$$R = \frac{Recycle_{mass}}{Turbine\ Exhaust_{mass}} \tag{A5.1}$$

In Bolland and Mathieu's analysis, the performance of the plant with R ≤ 40% was assessed. They stated that the upper limit would be R = 64% at which point a stoichiometric amount of O_2 exits the compressor – i.e. further recycling would affect the cycle's thermal and combustion efficiency. With R = 64% the gas turbine combustor would operate with the whole of the compressor exit gas passing through the flame region. By implication, Bolland and Mathieu (1998) must have assumed that the combustors were redesigned, as the conventional, dry low NOx combustors of the GE - 9FA would be unable to maintain stable combustion at the changed conditions. The authors stated that in a typical gas turbine combustor the O_2 concentration is of the order of 16 to 18% (presumably also on a mass basis). For R = 40%, the exhaust gas fractions of CO_2 and O_2 are, respectively, 6.3% and 8.1%, compared to 3.7% and 12.8% when no recirculation is used – i.e. the exhaust CO_2 concentration has approximately doubled. A further assumption made by Bolland and

Mathieu (1998) was that the recycled exhaust gas could be cooled to 25°C. This is important, as even a small increase in compressor inlet temperature has a marked effect on the performance of and work transfer to the compressor (Cumpsty, 2010) and such a high degree of cooling would not be possible in many applications given ambient conditions and cooling methods.

The cycle analysis performed by Bolland and Mathieu (1998) showed that introducing a PCC scrubbing plant decreases the power plant's efficiency by 8.7% points. If a SCGT cycle is introduced, the efficiency remains almost constant rising from 46.6% to 47.7% as R increases form 0% to 40%. However, with R = 40%, the exhaust gas mass flow rate entering the CO_2 scrubber decreases to 43% of its value without recirculation. Bolland and Mathieu concluded that the effect of recycling is not to increase cycle performance to any degree (although a change of 1% point can be seen as non-trivial to some analysts). Instead, they suggested that the most important result of using a SCGT cycle is to decrease the flow rate of flue gas sent to the PCC unit, while increasing the CO_2 concentration at the scrubber inlet. This, they argued, should lead to a smaller, cheaper facility, operating closer to its design point.

In a more recent paper, Lombardi (2001) described a life cycle analysis of a SCGT adapted, combined cycle. In the analysis both the CO_2 released and energy cost of building and operating a semi-closed plant were calculated. From this value, the net reduction in global emissions of CO_2 was evaluated. A semi-closed cycle based upon a 230 MW, 501F, Westinghouse/Mitsubishi gas turbine was considered fitted with a conventional amine based PCC unit, including CO_2 compression. The paper concluded that the reduction of CO_2 emissions in the life time of the plant was around 85% of the CO_2 emissions from a plant without SCGT cycle and PCC. Specifically, the amount of CO_2 produced during construction is two orders of magnitude less than the emissions during operation. One important benefit of semi-closing identified in the paper was the reduction in energy cost associated with dismantling the plant. This is due to the, the lower amount of materials in the scrubbing towers, which can be smaller in semi-closed cycle due to the reduced flow of flue gas.

In a recent paper, Sipöcz and Assadi (2009) also examined the implementation of a SCGT adapted NGCC. The base system used was a large frame, Alstom, GT26 gas turbine, with a triple pressure bottoming steam cycle and a base efficiency of 57.8%. In the paper Sipöcz and Assadi considered the detailed optimisation of whole process including, the PCC system and the bottoming steam cycle. R was restricted to 40%, to avoid combustor instability, citing Bolland and Mathieu's paper as justification.

Sipöcz and Assadi (2009) analysis showed a fall in thermal efficiency upon addition of capture and EGR of only 5.8%. This is a significantly better performance than calculated in the, albeit, much earlier paper of Bolland and Mathieu (1998). Unfortunately, the analysis was conducted at a fixed value of R = 40 % so the effect of EGR is difficult to discern. In addition, a relatively low ambient air temperature of 15°C with the EGR cooled to 25°C was assumed. These low temperatures are reasonable given the location of the authors in Norway, but are clearly difficult to achieve in other parts of the world. This is critical, as an increase in compressor entry temperature has a severe effect on the performance of the compressor, much more so than the changes in gas thermodynamic properties due to EGR.

c) Summary of principle effects of semi-closing of gas turbine cycles
Considering first the most significant change, semi-closing leads to a reduction in the consumption of air and hence the concentration of N_2 and O_2 in the exhaust stream, accompanied by a corresponding rise in the CO_2 content. In other words a fundamental characteristic of SCGT cycles is that they consume less air, so there is less N_2 diluting the CO_2 passing out of the plant. As a result the total mass flow rate of gas passing out of the plant, and hence through any PCC unit, is reduced. Most authors consider this latter effect, rather than the increase in CO_2 partial pressure, to be the most important benefit of semi-closing for PCC as it can lead to a significant reduction in the size of the absorber column.

Due to the higher CO_2 content, there is a rise in molar specific heat of the gas streams passing through the engine. This leads to a rise in engine specific work output for a given combination of turbine inlet temperature (TIT) and molar (and hence volumetric) flow rate. The higher CO_2 content affects the performance of the gas turbine's turbomachinery. Most authors argue, however, that this effect is small. In particular, the shape of compressor and turbine maps is insensitive to changes of gas thermodynamic properties unless these are gross (Cumpsty, 2010). In practice, the changes in properties that occur can be accommodated easily by slight adjustment of the flow through the machine, thereby returning the dimensionless mass flow rate to its original value. Hence, the existing turbomachinery of the core gas turbine can be retained with little or no modification – a clear benefit for retrofitting.

Because of the higher specific heat of the compressor exit gas and the reduced O_2 concentration of that gas, a fall in combustion temperature for a given equivalence ratio takes place. This leads to a corresponding fall in thermal NOx generation within the combustion chamber. It is likely that new, redesigned combustion chambers would be required, unless the degree of recirculation is small. Elkady et al. (2008) stated, however, that EGR levels of up to 35% are feasible without major modifications of existing combustion technology. Nonetheless, if a major change to the combustion chambers is required this is feasible on large frame gas turbines as these usually have cannular combustion cans that are designed to be changeable.

A further effect of semi-closing is the reduction in the fraction of the combustion chamber out gas actually released to the environment (or passed to a PCC unit) since the rest is recycled. As a result a reduction in aggregate emissions occurs for some pollutants, the concentration of which is determined by combustion equilibrium (principally carbon monoxide and NOx). However, substances such as sulphur and heavy metals simply accumulate in the recycle stream until the exhaust emissions release them at the rate at which they enter the cycle with the fuel. The emissions of these pollutants are, therefore, not reduced. This is not expected to be a problem for NGCC plants. As long as sweetened gas is being burned, there is only vestigial sulphur and heavy metal content to consider.

One last benefit of semi-closing is the significant recovery of water of combustion. Almost all of this H_2O is condensed in the flue gas cooler. So-called 'water harvesting' can provide an important source of water for the power plant itself and may have potential to be a source of fresh water for other uses. The removal of H_2O from the flue gas also results in a further rise in CO_2 concentration in the exhaust gas, over-and-above that due to the reduced N_2 flow rate.

d) Conclusions

Exhaust gas recycling appears to be technically feasible but is currently an area of ongoing research and commercial development. Aspects such as optimisation of recycle cooling, start-up and part-load operation, cost optimisation between recycle and capture costs etc. are matters that are important but that remain to be fully explored. It appears likely that any early natural gas combined cycle capture projects will use conventional gas turbines, with EGR units possibly emerging when a market is established to justify the costs of commercialisation. It remains to be seen whether or not any existing units can be modified to incorporate EGR as a retrofit.

Appendix 6 Effect of base plant efficiency on retrofit capture costs

This Appendix is based on Lucquiaud and Gibbins (2010) and considers the case of retrofits where plants receive the same electricity prices. Additional work for this project examines the case of replacement with new build plants with CCS, and explores the impact of base power plant efficiency on costs associated with CO_2 reduction by these two routes. Retrofit economics strongly depend on the electricity and carbon markets where fossil plant operates. One question to be considered in this context is how high would the cost of carbon in a competitive electricity market have to be for sub-critical and supercritical plants respectively to choose to retrofit CO_2 capture?

Obviously site-specific factors could affect retrofit economics, but these are not intrinsically related to the base plant steam conditions and so they can be assumed to be identical. It is also assumed that the same capture technology (assumed to be PCC hereafter, but similar considerations would apply to oxyfuel retrofits) would be available to both plants and that the efficiency penalty is the same irrespective of whether sub-critical or supercritical steam conditions are used (as shown in Appendix 1). The fuel input to a plant is assumed to be the same before and after retrofit so the base plant fuel and other costs do not change.

Significant changes then include additional capital costs and operating costs for the capture plant, CO_2 disposal costs and reduced total revenue associated with the reduced amount of electricity normally available to sell after retrofit. Lower carbon emission costs are, however, also incurred. At the break-even cost of carbon the net revenue from electricity sales with no capture and capture respectively would have to be equal, assuming that any risk premium for the retrofit project is included in the capital charge, as shown in the annual revenue balance per MW of plant capacity with no capture below:

$$POE_n * N_n - e * N_n * COC - FC - N_n * vc$$
$$= POE_c * N_c * \frac{(n-\delta)}{\eta} - FCC - e * (1-c) * N_c * COC - N_c * e * c * vcc - FC - N_c * vc \tag{A6.1}$$

Where:

Subscripts: n=no capture, c=CCS retrofitted

POE	\$/MWh	Time averaged price for electricity
N	hr	Annual operating hours
e	tCO_2/MWh	Time averaged specific emissions factor for plant
COC	\$/tCO_2	Cost of carbon emissions
η	% LHV	Plant thermodynamic efficiency with no capture
δ	%point LHV	Capture penalty
FCC/FC	\$/MW	Fixed charges for CCS retrofit / base plant (capital and fixed O&M)
C	-	Fraction of CO_2 captured
vcc/vc	\$/tCO_2 / \$/MWh	Specific variable costs for CCS/ base plant

A constant price for electricity at all times will be assumed in this analysis. Since the main purpose here is to compare sub-critical and supercritical plants this simplification is acceptable and helpful. But it will be shown below that the cost of carbon emissions required to cover capture costs is a linear function of the electricity price. So if capture can be interrupted during short periods with peak electricity prices, effectively reducing the average electricity price much more than the average capture level, the cost of adding capture can be significantly reduced. It is also assumed that the plant is at full output all the time it is operating, whereas in practice there may be occasions where part load operation occurs, e.g. to receive additional payments for electricity network support (ancillary) services. Again this simplification is justified in the context of the comparison being made here.

Rearranging equation A6.1 gives:

$$COC = \frac{POE_n * N_n - POE_c * N_c * \frac{(\eta - \delta)}{\eta} + FCC + N_c * e * c * vcc + vc * (N_c - N_n)}{e * [N_n - (1 - c) * N_c]} \qquad \text{(A6.2)}$$

It is reasonable to assume that the fixed capital charges for CCS retrofit will be proportional to the CO_2 emission capture rate per MW of plant capacity with no capture (i.e. what the unit has to be sized to do), so:

$$FCC = e * c * fcc \qquad \text{(A6.3)}$$

Where fcc $/(t$CO_2$/hr captured) specific fixed capital charges for CCS

It is quite likely that the operating hours of the plant will increase when capture is added since the marginal operating cost will be reduced and it is also possible that a different selling price may apply for electricity after retrofit depending on a number of factors including other potential developments in the electricity system. Leaving aside these (probably favourable) factors, however, and assuming that both of the above remain constant before and after capture, equation A6.2 reduces to:

$$COC = \delta * \frac{POE}{\eta * e * c} + \frac{fcc}{N} + vcc \qquad \text{(A6.4)}$$

By definition the specific CO_2 emissions from a plant burning the same fuel are inversely proportional to the plant thermal efficiency so:

$$\eta_{sub} * e_{sub} = \eta_{sup} * e_{sup} = \text{ specific emissions per MWth from the fuel} \qquad \text{(A6.5)}$$

So the carbon price ($/tonne for emissions to atmosphere) required to trigger capture retrofit on sub-critical and supercritical plants is identical, if they are burning the same fuel and other, site specific, factors are the same. In other words, there is no intrinsic effect of base plant efficiency.

This may seem like a surprising result but it arises from the combination of assumptions and observations that:

- all plants receive the same price for electricity in a market;
- electrical output lost, and hence one of the costs for CCS, is a function only of the amount of CO_2 captured; and
- other CCS costs also are assumed to be proportional to the amount of CO_2 captured.

Additionally, most studies have not looked at plants operating in a market with a common price when making this comparison, but have assumed that plants receive only their costs of electricity production. These are usually different for different types of plant. A common electricity price is particularly relevant for retrofit cases, however, since plants are likely to have paid off all or most of their initial capital and thus may have nominal production costs well below electricity market price levels that would allow capital recovery for a new plant.

It can also be noted that the lost capacity will probably be most critical at periods of high system demand, when total installed generation margins are under pressure. In this situation capture on retrofitted plants could, however, be designed to be temporarily interrupted to provide the same level of capacity as before, until additional generation capacity has been built (see Chalmers and Gibbins, 2007 for an introduction to this concept)

Although the carbon unit price (in $/tCO_2$) is the same, the total retrofit project costs (in $) to society (if society pays - which it must do in some way) of retrofitting sub-critical plants producing the same amount of electricity before retrofit as a fleet of supercritical plants is higher (see Table A6.1 overleaf). This is because the former emit more CO_2 in total to start with (and, therefore, more CO_2 is captured for the same initial electrical output) and produce less electricity afterwards. These costs are approximately inversely proportional to plant efficiency. Relative amounts of CO_2 to be captured, and hence CCS implementation costs and changes in electrical output relative to a sub-critical plant of the same initial capacity at 38% LHV nominal efficiency are shown in Table A6.2 (also on the next page).

But these subsequent benefits for supercritical plants when retrofitting CCS must be balanced against any additional costs for building plants with a higher initial efficiency. It seems likely that there will be cases where any extra costs may not be justified, even when taking into account estimated subsequent CCS retrofit project details (including retrofit timing and technical uncertainty involved). For example, there is an extensive CCR literature in this field (e.g. IEAGHG, 2007; Lucquiaud and Gibbins, 2009a; Lucquiaud et al, 2009b). An overall conclusion in this literature is that most optional pre-investments that could be made to reduce future capture costs are difficult to justify for economic reasons, partly due to typical assumptions for the time value of money. Note that this is not an argument for not retrofitting existing sub-critical plants, however, just a consideration when building such plants without capture, if capture might need to be retrofitted later.

Higher total retrofit project costs for lower efficiency plants do, however, mean that it is more likely that it will be cheaper to replace these plants with new build plants with CCS than retrofit either these or higher efficiency plants (since both retrofit options have effectively the same costs). When considering different options for capture retrofit, however, society (as well as the plant owner facing carbon charges) should be neutral about which existing plants to retrofit on the basis of initial plant efficiency alone. This is because there is not the option of retrospectively changing the efficiency of existing plants (except by paying for a boiler/turbine retrofit, or a complete rebuild). For the same initial MW capacity, lower efficiency plants cost more to retrofit with CCS but this results in bigger cuts in CO_2 emissions. Thus, provided the mix of site-specific conditions are comparable, if society has chosen to invest in retrofitting CCS on existing coal-fired power plants it should be an equally good use of money whether the initial plant has sub-critical or supercritical steam conditions.

Table A6.1 Worked examples of required carbon emissions costs to cover the cost of CCS on supercritical and sub-critical plants

Note: The values used are purely illustrative

The sub-critical plant gets a lower net revenue after paying carbon charges (or CCS costs) than the supercritical plant, an entirely predictable result given its higher specific carbon emissions. It is, however, unlikely that the relatively small difference would alone be sufficient to justify the construction of a new supercritical plant to replace the sub-critical plant. The new plant would have somewhat lower fuel, carbon and other operating costs but would also have to recover its capital costs. For an existing plant that would otherwise have to be closed down capital charges are effectively zero.

		Amine, supercrit PC plant	Amine, sub-crit PC plant
Original plant efficiency	%LHV	45%	38%
PRICE OF ELECTRICITY (doesn't change with capture)	$/MWh_e	80.00	80.00
Original plant MW		600.00	600.00
MWth		1333.33	1578.95
Efficiency penalty		9.00%	9.00%
Efficiency with capture		36.00%	29.00%
Plant MW with capture		480.0	457.9
Capture capital cost	$/kW_th	300	300
Total cost for capture plant	$.M	400.00	473.68
Capture plant life	yr	15.00	15.00
Interest rate		10.00%	10.00%
Annual percent capital recovery		13.15%	13.15%
Annual payment for capture CAPEX	$.M/yr	52.59	62.28
Load factor		85.00%	85.00%
hr on load/yr	hr	7446	7446
Consumables cost for capture plant	$/MWh_th	0.50	0.50
	$.M/yr	4.96	5.88
Variable O&M cost and other CCS variable costs	$/MWh_th	3.00	3.00
	$.M/yr	29.78	35.27
Revenue before all base plant costs and CO2 emissions costs considered			
Electricity sales revenue without capture	$.M/yr	357.41	357.41
Electricity sales revenue with capture	$.M/yr	285.93	272.76
Revenue with capture (after CCS fixed and variable costs subtracted)	$.M/yr	198.59	169.33
Specific CO2 emissions from fuel	t/MWhth	0.35	0.35
CO2 produced	Mt/yr	3.47	4.11
Emissions with 90% capture	Mt/yr	0.35	0.41
CO2 captured (so no cost for emission)	Mt/yr	3.13	3.70
CO2 emission cost to emit to break even	$/tonne CO2	50.78	50.78
Revenue before all base plant costs, but with CCS and/or CO2 emissions costs considered			
Net revenue without capture and with break-even carbon charges	$.M/yr	180.94	148.44
Net revenue with capture and with break-even carbon charges	$.M/yr	180.94	148.44

Table A6.2 Relative amounts of CO_2 to capture, capacity remaining and penalty per tonne of CO_2 capture for retrofit, compared to 38% LHV datum

LHV efficiency before retrofit	Relative amount of CO2 emissions to be handled for the same output before capture	Power after capture as fraction of original power	Relative MW penalty per tonne of CO2 avoided
36%	106%	75.0%	100%
38%	100%	76.3%	100%
40%	95%	77.5%	100%
42%	90%	78.6%	100%
44%	86%	79.5%	100%
46%	83%	80.4%	100%

Appendix 7 Parametric analysis of past post-combustion capture studies

An extended version of the analysis presented in:
Al-Juaied, M. and Whitmore, A., ‘Realistic Costs of Carbon Capture’, Belfer Center Discussion Paper 2009-08, July 2009.

COAL

	Studies based on HHV							Studies based on LHV			
Study	**MIT**	**MIT**	**MIT**	**Rubin**	**NETL**	**NETL**	**SFA**		**IEA GHG PH4/33**		**IEA 2010***
Steam cycle technology	SubC	SC	USC	SC	SubC	SC	SC		SC/Fluor	SC/MHI	USC
Without capture											
Efficiency (%, HHV)	34.3	38.5	43.3	39.3	36.8	39.1	39.5	Efficiency (% LHV)	44	43.7	46
TPC ($/kW)	1280	1330	1360	1442	1549	1575	1703	Capital cost	1222	1171	2200
With capture											
Efficiency (%, HHV)	25.1	29.3	34.1	29.9	24.9	27.2	31.2	Efficiency (% LHV)	34.8	35.3	36
TPC($/kWe)	2230	2140	2090	2345	2895	2870	2595	Capital cost	1755	1858	3400
Derived parameters											
% lost power output	26.8%	23.9%	21.2%	23.9%	32.3%	30.4%	21.0%		20.9%	19.2%	21.7%
Base plant TPC adjusted for efficiency $/kW	1749	1748	1727	1895	2289	2264	2156		1545	1450	2811
Capture plant $/kWe with capture	481	392	363	450	606	606	439		210	408	589
Capture plant $/kWth HHV with capture	120.7	115.0	123.8	134.4	150.8	164.8	137.0		69.6	137.3	201.9
Capture plant $/kWth HHV/base plant $/kWe	0.094	0.086	0.091	0.093	0.097	0.105	0.080		0.057	0.117	0.092
Efficiency penalty %HHV	9.2	9.2	9.2	9.4	11.9	11.9	8.3		8.8	8.0	9.5
LHV basis (assumed HHV = LHV * 1.05)											
Capture plant $/kWth LHV (assumed +5%) with capture	126.7	120.7	130.0	141.2	158.4	173.1	143.8	$/kWth LHV	73.1	144.1	212.0
Capture plant $/kWth/base plant $/kWe	0.099	0.091	0.096	0.098	0.102	0.110	0.084		0.060	0.123	0.096
Capture plant $/(kgCO2/hr)/base plant $/kWe**	0.333	0.306	0.322	0.330	0.344	0.370	0.284		0.201	0.414	0.324
Efficiency penalty %LHV	9.7	9.7	9.7	9.9	12.5	12.5	8.7		9.2	8.4	10.0
Electricity output penalty (kWh/tCO2)**	325	325	325	332	421	421	293		310	283	337

** based on 0.33kgCO2/kWh_th LHV and 90% capture

* central values from 2015 range

GAS

	Studies based on HHV			Studies based on LHV			
Study	**Rubin**	**NETL**	**SFA**		**IEA GHG PH4/33**		**IEA 2010***
Without capture					Fluor	MHI	
Efficiency (%, HHV)	50.2	50.8	50.7	Efficiency (% LHV)	55.6	55.6	57
TPC ($/kW)	671	554	723	Capital cost	499	499	900
With capture							
Efficiency (%, HHV)	42.8	43.7	45	Efficiency (% LHV)	47.4	49.6	49
TPC($/kWe)	1091	1172	1266	Capital cost	869	887	1450
Derived parameters							
% lost power output	14.7%	14.0%	11.2%		14.7%	10.8%	14.0%
Base plant TPC adjusted for efficiency $/kW	787.0	644.0	814.6		585.3	559.4	1046.9
Capture plant $/kWe with capture	304.0	528.0	451.4		283.7	327.6	403.1
Capture plant $/kWth HHV with capture	130.1	230.7	203.1		122.2	147.7	179.5
Capture plant $/kWth HHV/base plant $/kWe	0.194	0.416	0.281		0.245	0.296	0.199
Efficiency penalty %HHV	7.4	7.1	5.7		7.5	5.5	7.3
LHV basis (assumed HHV = LHV * 1.1)							
Capture plant $/kWth LHV (assumed +5%) with capture	143.1	253.8	223.5	$/kWth LHV	134.5	162.5	197.5
Capture plant $/kWth/base plant $/kWe	0.213	0.458	0.309		0.269	0.326	0.219
Capture plant $/(kgCO2/hr)/base plant $/kWe**	1.195	2.567	1.731		1.510	1.824	1.229
Efficiency penalty %LHV	8.1	7.8	6.3		8.2	6.0	8.0
Electricity output penalty (kWh/tCO2)**	456	438	351		459	336	448

** based on 0.21kgCO2/kWh_th LHV and 85% capture

* central values from 2015 range

Table References: (IEA, 2010a), (IEAGHG,2004), (MIT, 2007), (NETL, 2007), (Rubin, 2008), (Simbeck, 2007).

During the final editing of the report an additional study on comparative capture plant costs was released by the IEA (Finkenrath, 2011). Comparison between default values for this study (red numerical values) and the ranges reported in this working paper (bar graphs) are shown in Figure A7.1 overleaf. There are minor differences between the analysis methods used in this study (e.g. inclusion of pipeline transport and storage costs) but the effects of these are expected to be small. Default values used in this study for gas appear to give typical overall results, but capture equipment costs for coal appear low. To address this, the range of the sensitivity analysis in Figure 5.5.5 for capture plant cost for coal was extended, to 1500 $/(kgCO_2/hr) – vs the default value of 700 $/(kgCO_2/hr). Alternative metrics for this higher value are shown in italics below. As Figure 5.5.5 indicates, however, since capture plant costs contribute nearly equally to new build and retrofit, especially for more efficient plants, the effect of this increase on the relative LCOE difference between retrofit and new build cases is still limited, although overall costs are changed.

Figure A7.1 Impact of CO_2 capture costs for post-combustion capture from Finkenrath (2011), with equivalent new build plant data using default values and enhanced value of 1500$/(kg$CO_2$/hr for coal (latter shown in italics).

Appendix 8 Parametric modelling spreadsheet listing

A parametric comparison of integrated post-combustion capture retrofit with new build and retrofit using an additional energy source								
Version 15, jon.gibbins@ed.ac.uk, April 2011								
As described in IEAGHG Report "Retrofitting CO2 capture to existing power plants: effects of retrofit configuration and project technical and economic parameters on levelised electricity costs", published 2011								
This spreadsheet is supplied for research purposes only, no assurances are given in respect of its accuracy and correctness and users are themselves entirely responsible for any use they make of it.								
Colour coding	**Performance/ general**	**Economic**	**For information**					
	Comparison with other cases	**Comparison with other cases**	**Parameters to use in iteration**					
	Required input data is shown in **BOLD**							
A. Fully-integrated retrofit							**Coal default data**	**Gas default data**
Performance parameters for existing plant								
Existing plant fuel specific emissions	kgCO2/MWh LHV	**330**					**330**	**210**
Existing plant efficiency without capture	%LHV	**40%**					**40%**	**54%**
Power plant electricity output without capture	MW	**800.00**					**800.00**	**800.00**
Efficiency penalty for integrated capture plant	percentage points	**9.00%**					**9.00%**	**7.00%**
Capture level for post-com capture plant		**90%**					**90%**	**85%**
Existing plant compression and auxiliary power per tonne CO2 captured	kWh/tCO2	**135.00**					**135.00**	**170.00**
Existing plant CO2 heat requirements per tonne CO2 captured	GJ/tCO2	**3.00**					**3.00**	**3.10**
Existing power plant efficiency boost for 100% heat recovery from capture plant with additional heat input	percentage points	**1.00%**					**1.00%**	**0.00%**
Existing plant CO2 heat requirements per tonne CO2 captured	kWh/tCO2	833.33						
Total CO2 heat requirements	MWth	495.0						
Compression and auxiliary power	MW	80.2						
Drop in net output	MW	180.0						
Approximate gross output lost including boost from heat recovered	MW	99.8						
Approximate loss in gross output per tonne of CO2 captured, allowing for heat integration boost, with this capture auxiliary power and efficiency penalty	kWh/tonne	168.03						
COPx - Coefficient of Performance (power lost/heat supplied) for steam extraction		4.959						

Economic parameters for existing plant							Coal default data	Gas default data
Fuel costs (LHV basis)	$/MWh_th	**10.0**					**10.0**	**30.0**
Retrofit capital costs for existing plant excluding capture-related costs	$/kW before capture	**500.0**					**500.0**	**250.0**
Annual fixed charges for existing plant, before capture basis	$/kW before capture	**50.0**					**50.0**	**25.0**
Variable costs for existing plant, before capture basis	$/MWh before capture	**5.0**					**5.0**	**3.0**
Capital cost for capture plant, retrofit, including all charges up to first day of operation	$/(kgCO2/hr)	**700.0**					**700.0**	**1500.0**
Annual fixed costs for retrofit capture plant related to CAPEX		**2.00%**					**2.00%**	**2.00%**
Retrofit capture plant non-energy OPEX, based on CO2 captured	$/tCO2	**3.00**					**3.00**	**3.00**
CO2 emission charge	$/tCO2	**50.00**					**50.00**	**50.00**
CO2 transport and storage costs	$/tCO2	**10.00**					**10.00**	**10.00**
Interest rate		**10.00%**					**10.00%**	**10.00%**
Plant life after retrofit	years	**25**					**25**	**20**
Load factor for retrofitted plant, assumed to be all at full output		**80%**					**80%**	**80%**
Electricity costs for existing plant before capture assuming no capital expenditure								
Fuel costs	$/MWh	25.0						
Existing power plant fixed costs	$/MWh	7.1						
Existing power plant variable costs	$/MWh	5.0						
CO2 emission costs	$/MWh	41.3						
SRMC		78.4						
Cost, excluding CO2 emission charges	$/MWh	37.1						
Performance results for existing plant with integrated retrofit								
Power plant efficiency with capture	%LHV	31%						
Power plant electricity output with capture	MW	620.0						
Power plant fuel input	MWth	2000.0						
CO2 produced	tCO2/hr	660.0						
CO2 emissions with capture	tCO2/hr	66.0						
Specific emissions with capture	kgCO2/MWh	106.5						
CO2 captured	tCO2/hr	594.0						
CO2 captured per unit of electricity	kgCO2/MWh	958.1						
Power plant output as a percentage of the original power		78%						

Electricity costs for existing plant with integrated retrofit								
Existing plant CAPEX	$/kW with capture	645						
Capture plant CAPEX	$/kW with capture	671						
Total CAPEX	$/kW with capture	1316						
Capital charge rate - retrofit	%/yr	11.02%						
Running hours per year - retrofit	hrs/yr	7008						
Fuel costs	$/MWh	32.3						
Existing power plant CAPEX	$/MWh	10.1						
Existing power plant fixed costs	$/MWh	9.2						
Existing power plant variable costs	$/MWh	6.5						
Capture plant CAPEX	$/MWh	10.5						
Capture plant fixed OPEX	$/MWh	1.91						
Capture plant variable OPEX	$/MWh	2.87						
CO2 emission costs	$/MWh	5.3						
Captured CO2 T&S costs	$/MWh	9.6						
LCOE	$/MWh	88.3						
SRMC	$/MWh	56.49						
Cost, excluding CO2 emission charges	$/MWh	83.0						
Additional new-build power to give original plant output	MW	180.00						
Cost of that power at equivalent load factor and life	$/MWh	105.25						
Average LCOE for original power output including emission costs	$/MWh	92.11						
Average LCOE for original power output excluding emission costs	$/MWh	86.95						
Cost of abatement based on original power output	$/tCO2	69.33						

B. New plant with integrated capture								
Performance parameters for new plant								
			Integrated retrofit values for comparison	Ratio (if relevant & not 1)			**New SCPC**	**New GTCC**
New plant fuel specific emissions	kgCO2/MWh LHV	**330**	330				**330**	**210**
New plant efficiency without capture	%LHV	**45%**	40%	0.88			**45%**	**59%**
Power plant electricity output without capture	MW	775.00	800.00	1.03				
Efficiency penalty for integrated capture plant	percentage points	**9.00%**	9.00%				**9.00%**	**7.00%**
Capture level for post-com capture plant		**90%**	90%				**90%**	**85%**
New plant compression and auxiliary power per tonne CO2 captured	kWh/tCO2	**135.00**	135.00				**135.00**	**170.00**
New plant CO2 heat requirements per tonne CO2 captured	GJ/tCO2	**3.00**	3.00				**3.00**	**3.10**
	kWh/tCO2	833.33	833.33					
CO2 heat requirements	MWth	426.3	495.0					
Compression and auxiliary power	MW	69.1	80.2					
Drop in net ouput	MW	155.0	180.0					
Approximate gross output lost including boost from heat recovered	MW	85.9	99.8					
Approximate loss in gross output per tonne of CO2 captured, allowing for heat integration boost, with this capture auxiliary power and efficiency penalty	kWh/tonne	168.03	168.03	0.99				
COPx - Coefficient of Performance (power lost/heat supplied) for steam extraction		4.959	4.959					
Economic parameters for new plant							**New SCPC**	**New GTCC**
Fuel costs (LHV basis)	$/MWth	**10.00**	10.00				**10.00**	**30.00**
Capital costs for new plant excluding capture-related costs, before capture basis	$/kW without capture	**2000.00**	500.00	0.25			**2000.00**	**1000.00**
Annual fixed charges for new plant, before capture basis		**2.0%**					**2.0%**	**2.0%**
Annual fixed charges for new plant, before capture basis	$/kW	40.00	50.00	1.25				
Variable costs for new plant, before capture basis	$/MWh	**4.00**	5.00	1.25			**4.00**	**2.00**
Capital cost for capture plant, new build, including all charges up to first day of operation	$/(kgCO2/hr)	**700**	700				**700**	**1500**
Annual fixed costs for new capture plant related to CAPEX		**2.00%**	2.00%				**2.00%**	**2.00%**
New capture plant non-energy OPEX, based on CO2 captured	$/tCO2	**3.00**	3.00				**3.00**	**3.00**
CO2 emission price	$/tCO2	**50.00**	50.00				**50.00**	**50.00**
CO2 transport and storage costs	$/tCO2	**10.00**	10.00				**10.00**	**10.00**
Interest rate		**10.00%**	10.00%				**10.00%**	**10.00%**
Plant life	years	**25**	25		**25 for gas if coal replacement**		**25**	**20**
Residual value of new plant at end of retrofit life period	$/kW with capture	**0**					**0**	**0**
Load factor for new plant, assumed to be all at full output		**80%**	80%				**80%**	**80%**
					Limited existing planty life case	years	**15**	**10**
					Residual value	$/kW with capture	**2000**	**1200**

Performance results for new plant with integrated retrofit								
Power plant efficiency with capture	%LHV	36%	31%	0.86				
Power plant electricity output with capture	MW	620.0	620.0					
Power plant fuel input	MWth	1722.22	2000.00					
CO2 produced	tCO2/hr	568.33	660.00					
CO2 emissions with capture	tCO2/hr	56.8	66.0					
Specific emissions with capture	kgCO2/MWh	91.7	106.5					
CO2 captured	tCO2/hr	511.50	594.00					
CO2 captured per unit of electricity	kgCO2/MWh	825.0						
Power plant output as a percentage of the original power		80%						
Electricity costs for new plant with integrated retrofit with same load factor and life as retrofit								
New plant CAPEX	$/kW with capture	2500	645	0.25				
Capture plant CAPEX	$/kW with capture	578	671	1.16				
Total CAPEX	$/kW with capture	3078	1316	0.42				
Increase compared to equivalent non-capture plant		54%						
Capital charge rate for retrofit life	%/yr	11.02%	11.02%					
Running hours per year for retrofit load factor	hrs/yr	7008	7008					
Fuel costs	$/MWh	27.8	32.3	1.16				
New power plant CAPEX	$/MWh	39.3	10.1	0.25				
Fixed costs	$/MWh	7.1	9.2	1.29				
Variable costs	$/MWh	5.0	6.5	1.29				
Capture plant CAPEX	$/MWh	9.1	10.5	1.16				
Capture plant fixed OPEX	$/MWh	1.65	1.91	1.16				
Capture plant variable OPEX	$/MWh	2.48	2.87	1.16				
CO2 emission costs	$/MWh	4.6	5.3	1.16				
Captured CO2 T&S costs	$/MWh	8.3	9.6	1.16				
LCOE	$/MWh	105.2	88.3	0.83				
SRMC	$/MWh	48.1	56.5	1.17				
Cost, excluding CO2 emission charges	$/MWh	100.7						
Cost of abatement (assuming new plant sized to deliver original output)	$/tCO2	86.63						

Benefit (maximum) from possible increased load factor for new plant									
Running hours for new plant	hrs/yr	7008.00							
Additional running hours for new plant	hrs/yr	0.00							
Maximum net revenue earned per MWh over that period (SRMC difference)	$/MWh	8.40							
Revenue distributed over same running hours as existing plant	$/MWh	0.00							
LCOE for retrofit operating hours decreased by new revenue from additional hours	$/MWh	105.2	88.3	0.83					
Benefit for additional years of operation for new plant based on residual value									
Additional plant life	yrs	0							
Residual value of new plant at end of retrofit life period	$/kW with capture	0							
Multiplier for initial NPV of payment received at end of retrofit life		9.2%							
Reduction in effective initial CAPEX for new plant due to residual value	$/kW with capture	0.00							
LCOE reduction due to reduction in CAPEX for same load factor and life as retrofit	$/MWh	0.00							
LCOE for retrofit operating hours with additional load factor and life reductions	**$/MWh**	**105.2**	**88.3**	0.83					
ROI for retrofit plant if average electricity price is equal to equivalent LCOE for new plant									
(i.e. electricity price is enough to justify building the new plant to get specified ROI)									
Extra earnings per MWh from LCOE difference	$/MWh		17.0						
Extra earning per kW per year from LCOE difference	$/kW with capture		118.8						
Earnings per kW per year based on required capital charges	$/kW with capture		145.0						
Total income per kW per year	$/kW with capture		263.8						
Retrofit plant CAPEX	$/kW with capture		1315.8						
Capture plant life over which income arises	years		25.0						
ROI based on capital investment for retrofit	%	10.0%	19.8%	1.98					
(i.e. an electricity price expectation that would yield the required IRR on the new plant, taking into account possibly greater load factor and life, would yield this ROI on a retrofit plant)									

C. Retrofit with an additional plant providing heat and/or power									
Performance parameters			**Integrated retrofit values for comparison**	Ratio (if relevant & not 1)			**Additional coal boiler**	**Additional gas boiler**	**Additional GTCC**
Additional plant fuel specific emissions	kgCO2/MWh LHV	**210**	330	1.57			**330**	**210**	**210**
Additional plant energy utilisation factor	%LHV	**85%**					**90%**	**90%**	**85%**
Capture level for additional plant		**85.00%**	90.0%	1.05			**90.00%**	**90.00%**	**85.00%**
Additional compression and auxilary power per tonne CO2 captured	kWh/tCO2	**170.0**	135.0	0.79			**135.0**	**135.0**	**170.0**
Additional plant CO2 heat requirements per tonne CO2 captured	GJ/tCO2	**3.1**	3.0	0.96			**3.0**	**3.0**	**3.1**
	kWh/tCO2	861.1	833.3	0.96					
Economic parameters									
Economic parameters for existing plant for this type of retrofit							**Existing coal**	**Existing GTCC**	
Retrofit capital costs for existing plant excluding capture-related costs	$/kW before capture	**500.0**	500				**500.0**	**250**	
Annual fixed charges for existing plant, before capture basis	$/kW before capture	**50.0**	50.0				**50.0**	**25.0**	
Variable costs for existing plant, before capture basis	$/MWh before capture	**5.0**	5.0				**5.0**	**3.0**	
Capital cost for existing plant retrofit capture plant, including all charges up to first day of operation	$/(kgCO2/hr)	**700.0**	700				**700.0**	**1500**	
Annual fixed costs for existing plant retrofit capture plant related to CAPEX		**2.00%**	2.0%				**2.00%**	**2.00%**	
Non-energy OPEX, based on CO2 captured for existing plant retrofit capture plant	$/tCO2	**3.00**	3.0				**3.00**	**3.0**	
Economic parameters for additional plant							**Additional coal boiler**	**Additional gas boiler**	**Additional GTCC**
Additional plant fuel costs (LHV basis)	$/MWth	**30.00**	10.00	0.33			**10.00**	**30.00**	**30.00**
Capital costs for additional CHP plant, based on fuel input	$/kWth	**590**					**900**	**200**	**590**
Annual fixed costs for additional plant, related to CAPEX		**2.00%**					**2.00%**	**2.00%**	**2.00%**
Variable costs for additional plant, related to fuel input	$/MWh_th	**1.20**					**1.80**	**1.20**	**1.20**
Capital cost for additional plant capture plant, including all charges up to first day of operation	$/(kgCO2/hr)	**1500**	700	0.46			**700**	**700**	**1500**
Annual fixed costs for additional plant capture plant related to CAPEX		**2.0%**	2.0%				**2.0%**	**2.0%**	**2.0%**
Additional plant capture plant non-energy OPEX, based on CO2 captured	$/tCO2	**3.0**	3.0				**3.0**	**3.0**	**3.0**

C1. Retrofit with additional plant supplying 100% of heat and power requirements									
Extra input performance parameters for this case									
Additional plant power/heat ratio (MAY BE ADJUSTED TO GET TARGET POWER OUTPUT BELOW)		**0.1342**					**varies**	**varies**	**varies**
Performance results									
Thermal efficiency to electricity for additional plant		10.1%							
Heat output per MWh of fuel fired in additional plant		0.749							
MWh of heat required per per MWh of fuel fired to capture own CO2		0.154							
Ratio of fuel thermal input to available heat ouput		0.596							
Additional plant fuel input rate to meet existing+additional capture plant heat	MWth	830.93							
Existing plant fuel input rate for comparison	MWth	2000.0							
Electricity output from additional plant	MWe	83.6							
CO2 from additional plant fuel input	tCO2/hr	174.5							
Additional plant CO2 emissions after capture	tCO2/hr	26.2							
Additional plant CO2 emissions captured	tCO2/hr	148.3							
Auxiliary power for additional plant CO2 captured	MWe	25.2							
Existing plant power with integration boost	MWe	820.00							
Overall plant thermal efficiency	%LHV	28.2%							
Existing+additional plant power output after com. & aux. power - MAY BE TARGET VALUE	MWe	798.16							
Overall plant thermal input	MWth	2830.93							
Total CO2 produced	tCO2/hr	834.49							
Existing+additional plant CO2 emissions	tCO2/hr	92.2							
Existing+additional plant specific CO2 emissions	kgCO2/MWh	115							
Total CO2 captured (additional plus existing plants)	tCO2/hr	742.3							
CO2 captured per unit electricity	(kgCO2/hr)/MW	930.0							
Power sent out as percentage of the original power		100%							
Power generated by additional plant as percentage of MW out		10%							
Heat requirement	MWth	622.7							
Additional plant heat output	MWth	622.7							
Additional plant heat output as fraction of total capture heat requirements	%	100.00							
Efficiency of marginal power vs integrated retrofit	%LHV	21.4%							

Electricity costs for existing plant with additional plant that meets 100% of heat requirements						
Existing plant CAPEX	\$/kW with capture	501.150				
Existing plant capture plant CAPEX	\$/kW with capture	520.946				
CHP plant cost (per kW capacity to send out with capture)	\$/kW with capture	614.2				
Additional plant capture plant CAPEX based on additional plant CO2 captured	\$/kW with capture	278.7				
Total CAPEX	\$/kW with capture	1915.1				
Capital charge rate for retrofit life	%/yr	11.02%				
Running hours per year for retrofit load factor	hrs/yr	7008				
Fuel costs for existing plant	\$/MWh	25.1				
Existing power plant CAPEX	\$/MWh	7.9				
Fixed costs for existing plant	\$/MWh	7.2				
Variable costs for existing plant	\$/MWh	5.0				
Existing plant capture plant CAPEX	\$/MWh	8.2				
Existing plant capture plant fixed OPEX	\$/MWh	1.5				
Existing plant capture plant variable OPEX	\$/MWh	2.2				
Fuel costs for additional plant	\$/MWh	31.2				
Additional plant CAPEX	\$/MWh	9.7				
Fixed costs for additional plant	\$/MWh	1.8				
Variable costs for additional plant	\$/MWh	1.2				
Additional plant capture plant CAPEX based on additional plant CO2 captured	\$/MWh	4.4				
Additional plant capture plant fixed OPEX	\$/MWh	0.8				
Additional plant capture plant variable OPEX	\$/MWh	0.56				
CO2 emission costs	\$/MWh	5.8				
CO2 captured T&S costs	\$/MWh	9.3				
LCOE	\$/MWh	121.7				
SRMC	\$/MWh	80.4				
Cost, excluding CO2 emission charges	\$/MWh	115.9				
Additional new-build power to give original plant output	MW	1.84				
Cost of that power at equivalent load factor and life	\$/MWh	105.25				
Average LCOE for original power output including emission costs	\$/MWh	121.67				
Average LCOE for original power output excluding emission costs	\$/MWh	115.90				
Cost of abatement based on original power output	\$/tCO2	111.01				
Summary costs for comparison			**Integrated retrofit values for comparison**	**Ratio (if relevant & not 1)**	**Integrated new build values for comparison**	**Ratio (if relevant & not 1)**
Total CAPEX	\$/kW with capture	1915	1316	0.68	3078	1.60
Capital charge rate - retrofit	%/yr	11.02%	11.02%		11.02%	
Running hours per year - retrofit	hrs/yr	7008	7008		7008	
Fuel costs	\$/MWh	56.3	32.3	0.57	27.8	0.49
Existing power plant CAPEX	\$/MWh	7.9	10.1	1.28	39.3	4.98
Existing power plant fixed costs	\$/MWh	7.2	9.2	1.28	7.1	0.99
Existing power plant variable costs	\$/MWh	5.0	6.5	1.28	5.0	0.99
Capture plant CAPEX	\$/MWh	22.2	10.5	0.47	9.1	0.40
Capture plant fixed OPEX	\$/MWh	4.0	1.9	0.47	1.6	0.40
Capture plant variable OPEX	\$/MWh	4.0	2.9	0.71	2.5	0.61
CO2 emission costs	\$/MWh	5.8	5.3	0.92	4.6	0.79
Captured CO2 T&S costs	\$/MWh	9.3	9.6	1.03	8.3	0.88
LCOE	\$/MWh	121.7	88.3	0.72	105.2	0.86
SRMC	\$/MWh	80.4	56.5	0.70	48.1	0.59

C2. Retrofit with an additional plant with specified fuel input									
Extra input performance parameters for this case									
Additional plant power/heat ratio		**1.0000**					**varies**	**varies**	**varies**
Additional plant fuel input (MAY BE ADJUSTED)	**MWth**	**1824.6**					**varies**	**varies**	**varies**
Existing plant fuel input rate for comparison	MWth	2000.0							
Fraction of existing power plant capture heat met by additional plant (0-100%)		100.0%							
Existing power plant efficiency boost that will be obtained	percentage points	1.00%							
Performance results									
Thermal efficiency to electricity for additional plant		42.5%							
Heat output per MWh of fuel fired in additional plant		0.425							
Heat output	MWth	775.5							
Heat requirement for additional CO2 captured	MWth	280.5							
Heat available to send to existing plant	MWth	495.0							
Approximate extra power replacing this heat will produce	MWe	99.8							
Electricity output	MWe	775.5							
CO2 from additional plant fuel input	tCO2/hr	383.2							
Additional plant CO2 emissions after capture	tCO2/hr	57.5							
Additional plant CO2 emissions captured	tCO2/hr	325.7							
Auxiliary power for additional plant CO2 captured	MWe	55.4							
Existing plant net power with heat contribution and efficiency boost	MWe	739.8							
Overall plant thermal efficiency	%LHV	38.2%							
Existing+additional plant power output after com. & aux. power - MAY BE TARGET VALUE	MWe	**1459.90**							
Overall plant thermal input	MWth	3824.6							
Total CO2 produced	tCO2/hr	1043.2							
Existing+additional plant CO2 emissions	tCO2/hr	123.5							
Existing+additional plant specific CO2 emissions	kgCO2/MWh	84.6							
Total CO2 captured (additional plus existing plants)	tCO2/hr	919.7							
CO2 captured per unit electricity	(kgCO2/hr)/MW	630.0							
Power sent out as percentage of the original power		182%							
Power generated by additional plant as percentage of MW out		53%							
Heat requirement for both capture plants	MWth	775.5							
Additional plant heat output	MWth	775.5							
Additional plant heat output as fraction of total capture heat requirements	%	100.00							
Efficiency of marginal power vs integrated	%LHV	46.0%							

Electricity costs for existing plant with additional plant									
Existing plant CAPEX	$/kW with capture	274.0							
Existing plant capture plant CAPEX	$/kW with capture	284.8							
CHP plant cost (per kW capacity to send out with capture)	$/kW with capture	737.4							
Additional plant capture plant CAPEX based on additional plant CO2 captured	$/kW with capture	334.6							
Capital charge rate for retrofit life	%/yr	11.02%							
Running hours per year for retrofit load factor	hrs/yr	7008							
Fuel costs for existing plant	$/MWh	13.7							
Existing power plant CAPEX	$/MWh	4.3							
Fixed costs for existing plant	$/MWh	3.9							
Variable costs for existing plant	$/MWh	2.7							
Existing plant capture plant CAPEX	$/MWh	4.5							
Existing plant capture plant fixed OPEX	$/MWh	0.8							
Existing plant capture plant variable OPEX	$/MWh	1.2							
Fuel costs for additional plant	$/MWh	37.5							
Additional plant CAPEX	$/MWh	11.6							
Fixed costs for additional plant	$/MWh	2.1							
Variable costs for additional plant	$/MWh	1.5							
Additional plant capture plant CAPEX based on additional plant CO2 captured	$/MWh	5.3							
Additional plant capture plant fixed OPEX	$/MWh	1.0							
Additional plant capture plant variable OPEX	$/MWh	0.67							
CO2 emission costs	$/MWh	4.2							
CO2 captured T&S costs	$/MWh	6.3							
LCOE	$/MWh	101.3							
SRMC	$/MWh	67.9							
Cost, excluding CO2 emission charges	$/MWh	97.0							
Additional new-build power to give original plant output	MW	-659.90							
Cost of that power at equivalent load factor and life	$/MWh	105.25							
Average LCOE for original power output including emission costs	$/MWh	97.99							
Average LCOE for original power output excluding emission costs	$/MWh	94.05							
Cost of abatement based on original power output	$/tCO2	76.87							
Total CAPEX	$/MWh	25.64							

Summary costs for comparison			Integrated retrofit values for comparison	Ratio (if relevant & not 1)	Integrated new build values for comparison	Ratio (if relevant & not 1)
Total CAPEX	$/kW with capture	1631	1316	0.80	3078	1.88
Capital charge rate - retrofit	%/yr	11.02%	11.02%		11.02%	
Running hours per year - retrofit	hrs/yr	7008	7008		7008	
Fuel costs	$/MWh	51.2	32.3	0.63	27.8	0.54
Existing power plant CAPEX	$/MWh	4.3	10.1	2.35	39.3	9.12
Existing power plant fixed costs	$/MWh	3.9	9.2	2.35	7.1	1.82
Existing power plant variable costs	$/MWh	2.7	6.5	2.35	5.0	1.82
Capture plant CAPEX (includes additional plant costs)	$/MWh	21.3	10.5	0.49	9.1	0.42
Capture plant fixed OPEX (includes additional plant costs)	$/MWh	3.9	1.9	0.49	1.6	0.42
Capture plant variable OPEX (includes additional plant costs)	$/MWh	3.4	2.9	0.84	2.5	0.73
CO2 emission costs	$/MWh	4.2	5.3	1.25	4.6	1.08
Captured CO2 T&S costs	$/MWh	6.3	9.6	1.52	8.3	1.30
LCOE	$/MWh	101.3	88.3	0.87	105.2	1.03
SRMC	$/MWh	67.9	56.5	0.83	48.1	0.70
Benefit (maximum) from possible increased load factor for new plant						
Running hours for new plant	hrs/yr	7008.00				
Additional running hours for new plant	hrs/yr	0.00				
Maximum net revenue earned per MWh over that period (SRMC difference)	$/MWh	19.77				
Revenue distributed over same running hours as existing plant	$/MWh	0.00				
LCOE for retrofit operating hours decreased by new revenue from additional hours	$/MWh	105.2	101.3	0.96		
Benefit for additional years of operation for new plant based on residual value						
Additional plant life	yrs	0				
Residual value of new plant at end of retrofit life period	$/kW with capture	0				
Multiplier for initial NPV of payment received at end of retrofit life		9.2%				
Reduction in effective initial CAPEX for new plant due to residual value	$/kW with capture	0.00				
LCOE reduction due to reduction in CAPEX for same load factor and life as retrofit	$/MWh	0.00				
LCOE for retrofit operating hours with additional load factor and life reductions	$/MWh	105.2	101.3	0.96		
ROI for retrofit plant if average electricity price is equal to equivalent LCOE for new plant						
(i.e. electricity price is enough to justify building the new plant to get specified ROI)						
Extra earnings per MWh from LCOE difference	$/MWh		4.0			
Extra earning per kW per year from LCOE difference	$/kW with capture		27.9			
Earnings per kW per year based on required capital charges	$/kW with capture		179.7			
Total income per kW per year	$/kW with capture		207.5			
Retrofit plant CAPEX	$/kW with capture		1630.8			
Capture plant life over which income arises	years		25.0			
ROI based on capital investment for retrofit	%	10.0%	12.0%	1.19		
(i.e. an electricity price expectation that would yield the required IRR on the new plant, taking into account possibly greater load factor and life, would yield this ROI on a retrofit plant)						
Power plant output with additional plant retrofit (check on fuel input adjustment)	MW		1459.90			

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