Continued Operation of ‘Opted-Out’ Large Combustion Plants under the IED

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ABSTRACT

The Directive on Industrial Emissions (Industrial Emissions Directive (IED)) (Directive 2010/75/EU) was introduced by the European Union (EU) to replace seven existing EU Directives, with one of these being Directive 2001/80/EC (commonly known as the Large Combustion Plants Directive (LCPD)). Under the LCPD, power plant operators were required to limit the emissions to atmosphere of certain pollutants. However, power plant operators were also allowed to ‘opt out’ of the LCPD obligations on the condition that they close (cease operation) by the end of 2015 or after 20 000 hours of operation after 1 January 2008, whichever is sooner. The ‘opt out’ option was considered to be the preferred option for many power plant operators, particularly for those with ageing combustion plants where the considerable investment required to meet the new emissions limits was not considered to be viable.

The LCPD requirements were carried forward and are still valid under the IED. As a result, there are a number of power plants currently in operation that will need to cease operation by the end of 2015 (at the latest). The number of these power plants, and the associated reduction in generating capacity, varies significantly within each of the EU Member States, with the UK having the greatest potential loss totalling 12 GW (approximately 35 GWth)[1]. This reduction in generating capacity is also compounded by the ongoing decommissioning of ageing nuclear plant.

When coupled with the likely increases in demand for electricity and recent changes in attitude towards new nuclear plant development, this reduction in generating capacity suggests that a significant energy gap is on the horizon.

Therefore, a major increase in the demand for new power plant (i.e. new generating capacity) within the EU can be expected over the coming years.

However, the planning process associated with the development of a new power plant is often beset with major challenges. This can often lead to lengthy and costly consultation processes associated with locating suitable land with access to a grid connection and suitable cooling media, as well as in gaining public acceptance of the scheme. As such, the reuse of existing sites could be considered as an attractive alternative for the development of new or additional generating capacity to meet the energy gap in the short term.

The effects of the LCPD and IED on the operation of large combustion plants and the options available to power plant operators who have previously ‘opted out’ under the LCPD are discussed in a separate Paper produced by Parsons Brinckerhoff entitled ‘Future Prospects for Large Combustion Plants’[1]. The object of this current Paper is to further investigate the available options to allow such power plants to continue operation beyond the end of 2015, and to assess the practicalities and financial viability of carrying out the required modifications to meet the new IED limits.

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[1] *‘Future Prospects for Large Combustion Plants’ (Published by Parsons Brinckerhoff, June 2011)*

1 INTRODUCTION

The requirements of Directive 2001/80/EC (commonly known as the Large Combustion Plants Directive (LCPD)) introduced to limit the emissions to atmosphere of certain pollutants and the consequences of certain ‘opt out’ provisions contained therein, has resulted in a scenario which could see the potential shut down of some 130 GWth of power generation capacity within the EU by the end of 2015. This, combined with the likely increases in demand for electricity, the ongoing decommissioning of ageing nuclear plant and recent changes in attitude towards new nuclear plant development, suggests that a significant energy gap is on the horizon.

Whereas the growing energy gap is expected to lead to a major increase in the demand for new-build plant, it is also expected to introduce new opportunities for older plant which had chosen to ‘opt out’ under the LCPD legislation. Increased demand for new-build plant is likely to drive up market prices, which may result in further investment in older plant becoming more financially viable, whereas suitable greenfield sites for new-build opportunities are likely to be hard to find. The availability of existing infrastructure, grid connections, suitable cooling media and generating licences along with long-term public acceptance of the facility may therefore offer certain advantages over new greenfield developments which will require extensive planning and consultation.

Under the LCPD legislation, any plant which had previously opted out was able to continue operation beyond the specified closure date, provided it was able to meet the requirements for ‘new plant’. This requirement has been carried through to the new Directive and therefore still applies to all current plant. Any opted-out plant wishing to continue operation beyond 1 January 2016 will therefore need to meet the ‘new plant’ requirements of the IED.

The effects of the LCPD and IED on the operation of large combustion plants and the options available to power plant operators who have previously ‘opted out’ under the LCPD are generally discussed in a separate Paper produced by Parsons Brinckerhoff entitled ‘Future Prospects for Large Combustion Plants’. The following analysis is aimed at expanding on these options and exploring the relative costs and practicalities in comparison with a new greenfield power plant development.

The available options as identified in our previous study and further discussed herein are generally summarised as follows:

- Plant upgrade – installation of pollution control measures
- Plant refurbishment – replacement of main plant equipment i.e. boilers, turbines
- Plant conversion – conversion to alternative fuel source or technology
- Reuse of site – completely replace plant on existing site

2 IED REQUIREMENTS

2.1 General

The IED replaced seven existing EU Directives, one of these being the LCPD. Although it should be noted that while the IED effectively replaces the requirements of the LCPD, the requirements of the LCPD still apply for 'opted-out' power plant.

Therefore, for any LCPD 'opted-out' power plant to remain in operation beyond 1 January 2016, it must meet the IED requirements for 'new plant'. This is detailed in Article 30(2) of the IED, concerning 'Emission Limit Values', which states that:

"*All permits for installations containing combustion plants which have been granted an exemption as referred to in Article 4(4) of Directive 2001/80/EC* [i.e. the 'opted-out' plants] *and which are in operation after 1 January 2016, shall include conditions ensuring that emissions into the air from these plants do not exceed the emission limit values set out in Part 2 of Annex V".*

The emission limit values from Part 2 of Annex V of the IED are discussed further in subsequent sections of this study.

In a similar manner to that of the LCPD, the IED includes provisions for derogation for existing power plant against the 2016 emissions limits. This is detailed in Article 33, concerning 'Limited Life Time Derogation'. As such, existing power plant may be exempt from compliance with the IED requirements provided that operation is limited to no more than 17 500 hours between 1 January 2016 and 31 December 2023, although the power plant must comply with the emission limits set by the LCPD for 'new plant'. Exemption under the IED regulations has not been considered as part of this study, which is focused on the potential closure of power plants in 2015, although it is expected that similar considerations will apply at the end of the applicable exemption period.

2.2 IED emissions limit values

The emissions limit values specified under Part 2 of Annex V of the IED (i.e. those which would apply for the continued operation of 'opted-out' power plant under the LCPD) are listed in Table 2.1.

For comparison purposes, typical emissions values have also been included which relate to those of a typical combustion plant, of the type which is expected to be 'opted out' under the LCPD. The value used in the study for sizing purposes has been shown in brackets.

TABLE 2.1

EMISSIONS LIMITS

Pollutant	Fuel*	Limit			Assumed current levels *Numbers based on reference plant model*
		50-100 MWth mg/Nm^3	100-300 MWth mg/Nm^3	>300 MWth mg/Nm^3	
SO_x	Solid Fuel **	400	200	150	Depends on fuel (3150)
	Biomass	200	200	150	
	Gaseous Fuel	35	35	35	
NO_x	Solid Fuel **	300	200	150	800-1000 (975)
	Biomass	250	200	150	
	Gaseous Fuel	100	100	100	
CO	Solid Fuel **	N/A	N/A	N/A	Negligible at 100% load
	Biomass	N/A	N/A	N/A	
	Gaseous Fuel	100	100	100	
Dust (Particulate matter)	Solid Fuel **	20	20	10	
	Biomass	20	20	20	
	Gaseous Fuel	5	5	5	
CO_2		N/A	N/A	N/A	

* Note that the Table is for fuels with the exception of gas turbines and gas engines

** Solid fuel means 'coal and lignite and other solid fuels'

2.3 Reduction of plant emissions

2.3.1 General

To allow operation beyond January 2016, any opted-out plant will be required to reduce the emission of all pollutants to within the IED limits. There are various methods and technologies available to achieve this, although the preferred method will vary for each specific plant. A brief description of the main pollutants and some of the available pollutant abatement techniques are discussed in the following sections along with their relevance to this study.

2.3.2 Sulphur dioxide (SO_2)

Upon combustion, the majority of the sulphur content of the fuel becomes Sulphur Dioxide (SO_2). SO_2 is an irritant gas that, in high concentrations, provokes broncho-constriction (narrowing of the airways). Once released into the atmosphere, SO_2 is also one of the pollutants that contribute to the formation of acid rain.

The concentration of SO_2 in the flue gas discharged from a power plant ultimately depends on the fuel being used and its associated sulphur content. For coal, which typically has a sulphur content ranging from 0.1 to 3.5 per cent, 95 per cent of the sulphur in the fuel is usually discharged to atmosphere as SO_2. Furthermore, typical concentrations of SO_2 in the flue gas when burning coal is 2000 mg/m^3 (dry, 0°C, 1013 mbar, 6 per cent oxygen) per 1 per cent sulphur content by mass.

Possible methods of SO_2 abatement or prevention for existing steam boilers include:

a. Switch to coal with a lower sulphur content

b. Switch to an alternative fuel

c. Displacement of coal burn via waste heat (often recovered from gas turbines - repowering)

d. Flue gas desulphurisation (FGD)

e. Replacement of the boiler with a fluidised bed boiler

f. Increasing efficiency

g. Alternative technology (gas turbines)

Other techniques such as in-furnace sulphur control or the modification of existing boilers to fluidised bed are also possible, although these are expected to have limited application potential and have not been considered further.

When considering the addition of new plant to the sites, there are many technologies which offer very low or zero SO_2 emission levels, for example, gas-fired power generation or clean coal technologies such as fluidised bed combustion or gasification.

2.3.3 Oxides of Nitrogen (NO_x)

There are two types of Oxide of Nitrogen produced during the combustion process. Nitrogen oxide (NO) is the principal product produced, with a small portion of nitrogen dioxide (NO_2). The ratio of formation of NO_2 to NO is approximately 1:19.

In terms of direct human health and environmental effects, it is the NO_2 which is of main concern. At high levels NO_2 causes inflammation of the airways and can affect lung function. In addition, high levels of NO_2 can have an adverse effect on vegetation as it can contribute to acidification and/or eutrophication of sensitive habitats leading to loss of biodiversity. However, as NO is a source of NO_2 in the atmosphere, combined emissions of NO_x must be considered.

NO_x formation during combustion is strongly dependent on several factors, but mainly relates to the interaction of fuel, air, flame temperature and the time the hot gases remain at this temperature. The quantity of nitrogen in the fuel also contributes, but this effect is less significant. Therefore, control of these factors is the basis of a number of NO_x control strategies involving combustion process control and burner design.

Typical concentrations of NO_x in the flue gas when burning coal range from approximately 900 to 1400 mg/m^3.

Possible methods of NO_x abatement or prevention for existing steam boilers include:

a. Low NO_x burners

b. Fuel selection (i.e. low nitrogen content)

c. Operational adjustments such as low excess air, altering burner use, reduction in combustion air temperature, coal/primary-air balancing, etc

d. Selective Catalytic Reduction (SCR)

e. Selective Non-Catalytic Reduction (SNCR)

f. Flue gas recirculation (FGR)

g. Combined SO_2 and NO_x removal (absorption/adsorption methods)

h. Over-fired air (OFA)

i. Reburn

j. Increasing efficiency

k. Displace coal burn with other fuels such as natural gas or syngas (N_2 can be removed from syngas prior to combustion)

l. Displace coal burn by augmenting boiler with waste heat recovery (eg from gas turbines)

m. Modify boilers to fluidised bed design

Each of these technologies is commercially proven albeit with some limitations; for example while SCR is an applicable technology for reducing NO_x emissions it is unproven when applied to flexible plant operation due to its requirement for a narrow temperature window. While Low NO_x burners and other primary control techniques will not be able to achieve the emissions limit values for NO_x on thermal plant they can reduce the NO_x emissions to reduce the space and cost impact of SCR or SNCR.

2.3.4 Carbon Monoxide (CO)

Carbon monoxide (CO) is formed during incomplete combustion of carbonaceous fuels, where carbon containing compounds are only partially oxidised due to an insufficient amount of oxygen.

Exposure to CO poses a threat to human and animal health as it leads to the formation of carboxy-haemoglobin which substantially reduces the capacity of the blood to carry oxygen.

IED requirements on CO only apply to gas-fired plant and so their abatement methods are not discussed further in this analysis.

2.3.5 Particulate matter

During combustion, Particulate Matter (PM) is formed from both unburned carbon in the fuel and non-combustible ash (forming mineral matter in the fuel which is released during combustion and carried to the atmosphere in the flue gas). Approximately 80 to 90 per cent of the ash in the coal is entrained in the flue gases leaving the boilers, with the remainder removed from the bottom of the boilers.

PM comprises both solid and liquid material which is suspended in the flue gas and emitted to the atmosphere. PM can have a variety of damaging environmental effects (including soiling of surrounding areas) and a number of health effects (including lung cancer and heart disease).

Furthermore, if the fuel contains or produces toxic substances (e.g. heavy metals, dioxins, polynuclear aromatic hydrocarbons) these can also become concentrated in the ash. Therefore, a reduction in emissions of these substances occurs with a reduction in emissions of PM.

It should also be noted that the lower temperatures of combustion in low NO_x burners increases the proportion of fly ash produced and the reduced oxygen levels can cause an increase in the carbon content of the ash.

Possible methods of particulate abatement or prevention for existing steam boilers include:

1. Electrostatic precipitators (ESPs)
2. Fabric filters (also called bag filters)
3. Ceramic filters
4. Wet scrubbers
5. Cyclones

2.3.6 Carbon Dioxide (CO_2)

Carbon dioxide (CO_2) is released during the combustion of any fossil fuel. However, at present coal typically produces about twice as much CO_2 as gas per unit of electricity generated[2]. CO_2 released into the atmosphere is believed to be increasing in concentration and has been linked to climate change. As such, CO_2 is now the focus of many emissions reductions targets.

However, the EU does not currently set limit values for CO_2 emitted from power plant. Nevertheless, CO_2 emissions are taxed in some EU Member States and all EU Member States must comply with the Emissions Trading Scheme (ETS).

Possible methods of CO_2 abatement include:

a. Increased plant efficiency
b. Repowering by replacing coal boilers with gas turbines (GTs) and heat recovery steam generators (HRSGs) to supply steam to existing steam turbines (STs)
c. Oxyfuel combustion: during oxyfuel combustion the fuel is burned with oxygen instead of air. Firing with oxygen allows the CO_2 to be extracted relatively easily as the products of the combustion are CO_2 and water vapour with no nitrogen.
d. Post-Combustion carbon capture: CO_2 is captured from the exhaust gas stream by absorption by solvents.
e. Pre-Combustion carbon capture: the fuel is pre-treated and converted into CO_2 and hydrogen. The hydrogen is then burned as the fuel.

The release of CO_2 emissions from power plants is the subject of many studies and reports produced within the industry. Although it is widely anticipated that limits will be imposed by the EU in the not too distant future, CO_2 is not currently considered under the IED regulations. CO_2 emissions have not therefore been considered further as part of this analysis.

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[2] *Overarching National Policy Statement for Energy (EN-1): Version for Approval (June 2011). Department of Energy and Climate Change (URN 11D/711)*

3 GENERAL ASSUMPTIONS

3.1 Introduction

The combustion plants which have opted out under the LCPD and therefore in line to cease operation by the end of 2015 are expected to encompass a wide range of technologies, unit ratings and fuel types. It would not be possible to analyse each and every scenario and so, for the analysis, a typical 'reference plant' was selected for comparison purposes. The parameters of the 'base reference plant' were selected to be representative of a typical, utility-scale thermal power plant which would be expected to be opted out under the LCPD regulations.

As the main contributing factor to power plant emissions, it was envisaged that the choice of fuel type would have a major impact on the outcome of the analysis, with there being a significant difference between hard coals and lignites. Given that lignite plants represent the top 12 polluting plants in the WWF 'Dirty Thirty' report[3], lignite was selected as being the most appropriate fuel for the evaluation. The use of lignite is also expected to represent a 'worst case' scenario, with the impact on hard coal fired plants expected to be less.

3.2 Base reference plant

The analysis was based on a four unit, subcritical pulverised fuel (pf) plant, with each unit having a gross electrical power output of 500 MW. It was assumed that cooling would be by means of water-cooled surface condensers and conventional natural-draft cooling towers and included no district heating or process heat export.

A summary of the base reference plant main parameters is as follows:

Parameter	**Value**	**Unit**
Unit size	500	MW
Gross plant electrical output	2000	MW
Net plant electrical output	1835	MW
Net heat rate (LHV)	9466	kJ/kWh
Net efficiency (LHV)	38.0	%
Ambient dry bulb temperature	9	°C

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[3] WWF report May 2007

Relative humidity	80	%
Fuel type	Lignite	-
Fuel LHV (moisture and ash included)	9053	kJ/kg

3.3 Financial parameters

In addition to the initial capital costs, it is expected that many of the changes will have an effect on performance which will have a further financial impact to the operator. This may be in relation to fuel costs where efficiency has been affected or where fuel type has been changed, or in lost revenue where net output has reduced. A significant increase in plant net output has not generally been considered as it is likely that this would introduce various complications with respect to grid connections etc.

The full financial implications of the above would require a separate full and detailed study and so have not been fully considered in this analysis. However, the incremental operating costs relative to the capital outlay must be considered to allow a fair comparison of the options to be made. A high-level analysis has therefore been carried out using the following assumptions:

Parameter	**Unit**	**Value**
Cost of coal (lignite)	€/GJ	1.8
Cost of natural gas	€/GJ	6
Selling price of electricity	€/kWh	0.058
Plant operating life	Years	25
Discount rate	%	10
Annual operating hours (coal)	hrs	7884 (availability 90%)
Annual operating hours (coal with FGD)	hrs	7709 (availability 88%)
Annual operating hours (gas)	hrs	8234 (availability 94%)

4 PLANT UPGRADING

4.1 Introduction

The first option available to the power plant operator is to upgrade the existing plant to meet the new emission limits of the IED. Plant upgrading is considered as additions and/or changes to the plant without major changes to the major items of the power island.

4.2 SOx reduction

Approximately 95 per cent of the sulphur in coal is emitted as SO_2, therefore the most effective means of reducing SO_2 emissions is by controlling the sulphur content of the coal. This would usually involve the sourcing of an alternative fuel supply to that previously being used by the plant. However, for an existing power plant it is likely that there is limited scope in pursuing this option as the location of the plant will almost certainly have been originally based on the local availability of coal. Transport costs associated with bringing coal in from further afield are likely to be prohibitive and may not be practical for certain lignite fuels.

If the sulphur content of the coal can not be controlled, then the other option is to remove the SO_2 directly from the exhaust gases using Flue Gas Desulphurisation. FGD is the removal of SO_2 from the flue gas prior to discharge to the atmosphere. Whilst offering the benefit of reduced emissions of SO_2, this will result in increased energy consumption and the production of significant quantities of solid and liquid waste. The wet limestone method is the most common and the type most generally applicable to inland sites, although other techniques such as sea water scrubbing are also available.

The FGD plant would normally remove about 95 per cent of the SO_2 from the flue gases. It is possible to remove a smaller percentage by designing the plant to treat only a proportion of the flue gases; this can result in a smaller, less costly FGD system, although to meet the IED limits it is likely that the full flow would have to be processed. In addition to the cost of the FGD system, there would also be a cost associated with the upgrading of the induced draft (ID) fans which would be required due to the additional pressure drop across the FGD system.

While offering the benefit of reduced emissions of SO_2, FGD will result in increased energy consumption. The FGD plant itself will consume a certain amount of auxiliary power although the ID fans will also consume more power to overcome the additional gas-side pressure drop. Auxiliary power consumption varies with system design, but based on the reference model, the increase in auxiliary power consumption is expected to be in the region of 6.5 MW per 500 MW unit. The addition of FGD is also expected to reduce the station availability by up to 2 per cent.

In addition to the above, the FGD process also produces significant quantities of solid and liquid waste. The solid byproduct, gypsum, may be saleable but there is no assurance that a buyer will be found; if not, the waste will require disposal. Additional water will also be required for the process.

4.3 NOx reduction

The primary factors behind NO_x formation are high temperatures, residence time and availability of oxygen. Low NO_x burners reduce combustion temperature and the availability of oxygen by delaying the combustion process in the furnace. These burners can have a much longer flame due to the prolonged combustion process.

While low-NO_x burners are considered as an available option, it is expected that most power plants will have either already installed low-NO_x burners or will soon do so in response to the improvement plans required by the Environmental Authority in each station’s IPC Authorisation. This option has not therefore been considered further and has been assumed to form part of the base case for each plant.

Selective catalytic reduction (SCR) is a further method of reducing NO_x emissions which involves the injection of ammonia into the flue gas stream and subsequent passage of the flue gases through a honeycomb of catalyst. The NO_x reacts with the ammonia to produce nitrogen and water vapour; removal efficiencies are in the order of 90 per cent.

For large power stations such as those being considered, large quantities of ammonia are required. This is usually delivered and stored as anhydrous ammonia. This is a hazardous chemical which is stored under pressure and requires careful handling.

There is a considerable auxiliary load associated with the installation of SCR including an uprating of the ID fans because of the greater gas-side pressure drop.

4.4 Implementation

In order to meet the IED requirements, it is expected that any existing plant will be required to install both FGD and SCR. The cost of installing the FGD and SCR for the reference plant is estimated at €780m.

In addition to the capital cost, it is expected that there will be an additional cost impact due to changes in performance. The effects on performance for the typical reference plant are summarised as follows:

TABLE 4.1

PERFORMANCE IMPACT OF PLANT UPGRADING

Description	Net plant output MW	Net plant heat rate kJ/kWh	Net plant efficiency %	SOx mg/nm³	NOx mg/nm³	Cost €m
Reference plant	1835	9466	38.0	3154	975	-
Addition of FGD and SCR	1798	9662	37.3	150	200	780

It can be seen from the above that for a typical 2000 MW power plant, the introduction of FGD and SCR is expected to result in a reduction in net plant output of around 37 MW and an increase in plant heat rate of around 2 per cent. Assuming that the fuel input to the boiler is the same, this will result in a potential loss of revenue in the order of €200 million (presented as net present value (NPV) over a 25-year period).

It should be noted that the above is based on the assumption that no further upgrade or modification work is required to the existing power island equipment, and that the plant is otherwise in a suitable condition to allow further long-term operation. In reality, this is expected to be an optimistic view with at least some refurbishment work required. As this will vary on a plant by plant basis, it would not be practical for consideration as part of this analysis.

The costs associated with the implementation of an FGD system are fully dependent on the flue gas volume and the amount of sulphur to be removed. The specific fuel being used and the associated sulphur content will therefore have a major effect on the costs for any given power plant.

5 PLANT REFURBISHMENT

5.1 Introduction

Should the existing plant not be in a suitable condition to allow continued long-term operation, there are a number of plant refurbishment options available to the power plant operator. Plant refurbishment is considered as the replacement of major items of the power island including the boiler and the steam turbine, without changing the fundamental arrangement (boiler and turbine) to provide a more efficient plant.

It should be noted that this is not a replacement for the emissions control methods described in the previous section. Emissions controls would have still have to be implemented, but a more-efficient plant will emit less per unit generation requiring smaller, less costly emissions control plant.

Whereas there are a large number of options which are theoretically available, these have been limited to those with a practical application for the size and type of plant under consideration.

5.2 Replace main plant (subcritical pf)

Replacing the existing boiler with a new subcritical boiler allows a small increase in boiler efficiency, so reducing fuel consumption and emissions. Although it is likely that such a refurbishment would be accompanied by other refurbishments, this option looks purely at a replacement boiler.

Replacing the steam turbine in addition to the boiler not only allows for newer, more efficient equipment but allows the steam conditions to be increased, giving a further increase in efficiency. The existing feed heating plant and other auxiliary equipment could still be utilised.

5.3 Replace main plant (supercritical)

To maximise efficiency, this option considers the replacement of the existing subcritical plant with new supercritical plant. Based on current market trends and the availability of proven designs, the configuration for the supercritical option has been changed to 2 x 1000 MW blocks as opposed to the reference plant design of 4 x 500 MW blocks.

5.4 Replace main plant (subcritical CFB)

Although supercritical units would give a higher efficiency, to date the largest supercritical circulating fluidised bed (CFB) units are 460 MW. Only subcritical CFB boilers have therefore been considered. The steam conditions are assumed to be unchanged from the reference conditions and so the existing steam turbine has been retained.

Based on the lower furnace temperature in a CFB boiler, the NO_x emissions are lower than for a pf boiler and it is likely that SCR may not be required. FGD is also not required because limestone is injected directly into the fluidised bed.

5.5 Implementation

For comparison purposes, each of the options has considered that the gross plant output is maintained at a maximum of 2000 MW, in line with that of the reference plant. A summary of the options is included in Table 5.1 below:

TABLE 5.1

PERFORMANCE IMPACT OF PLANT REFURBISHMENT

Description	Net plant output MW	Net plant heat rate kJ/kWh	Net plant efficiency %	SOx mg/nm³	NOx mg/nm³	Cost €m
Reference plant	1835	9466	38.0	3,150	975	-
New subcritical boiler (FGD)	1811	9488	37.9	150	200	1,616
New subcritical boiler and steam turbine (FGD)	1800	9327	38.6	150	200	1,846
New supercritical boiler and steam turbine (FGD)	1785	8776	41.0	150	200	2,389
CFB, existing steam turbine	1828	9365	38.4	150	200	1,128

The analysis shows that any of the above options can be applied to allow the plant to meet the IED limits, although there is a wide range of associated costs. The CFB option appears to be the most attractive option with the lowest installed capital cost and a marginal improvement in efficiency. Conversely, the supercritical option represents the highest improvement in efficiency, although the high capital costs suggest that this option would not be attractive to the power plant operator. These issues are discussed further as part of the financial analysis.

It should be noted that the efficiency for the supercritical option is less than that quoted in some publications. This is due to the lignite fuel and to some extent the use of cooling towers instead of a once-through system.

6 PLANT CONVERSION

6.1 Introduction

As an alternative to plant refurbishment, there are a number of options relating to plant conversion. Plant conversion generally involves the switch to an alternative fuel source (other than coal) whilst retaining as much of the original plant equipment as practicable.

6.2 Biomass conversion

There is general market interest in the conversion of pf coal boilers to 100 per cent biomass firing, although at present full conversion would require a new boiler of different design. Modern coal-fired stations use pulverised fuel, whereas solid biomass plants use stoker-fired boilers. CFB boilers have been developed to burn biomass, but these are usually smaller subcritical units.

Depending on the fuel, it is possible that conversion to biomass may result in a reduction of SO_2 and NO_x, although the main driver for biomass conversion is a reduction of CO_2 emissions. As CO_2 is not one of the main concerns under the IED regulations, biomass conversion has not been considered further.

6.3 GT repowering

The repowering of steam power plant generally refers to the concept of using an external source of heat to replace or supplement the thermal output of an existing boiler. The external source of heat may be supplied by GTs. GT repowering can improve the thermodynamic performance of the existing coal-fired steam plant and displace some or all of the original coal consumption with natural gas which results in lower emissions.

There are many GT repowering configurations possible, however ‘boiler replacement’ repowering, where GTs are installed to convert a coal-fired steam cycle unit to full combined cycle, is considered to be the most effective. This method requires the greatest capital investment and would therefore normally only be considered when the boiler is approaching the end of its useful life, but there are correspondingly greater gains in efficiency and output.

GT repowering introduces a number of complications due to the fact that the existing steam turbine has not been specifically designed to match the GT/HRSG combination. As a result, it is often the case that the steam turbine needs to be derated due to non-optimised steam conditions. In addition, the fact that GTs are produced in discrete sizes means that it is extremely difficult to achieve a final configuration that has the same output as the original configuration, resulting in a lower overall plant output (higher outputs are possible although it is unlikely that available grid connections would cater for this).

Other repowering options are also available, including feedwater heating repowering, hot windbox repowering and supplementary HRSG repowering. These do not give similar improvements in efficiency and output and have not therefore been considered further as part of this analysis, although they may be relevant for some specific applications.

6.3.1 Implementation

For comparison with the reference design, the repowering of one boiler unit has been considered. The resulting generator output of the repowered unit is 432 MW and the net output of the resulting CCGT cycle is 1289 MW. To maintain a capacity similar to that of the original, it is assumed that one of the other boiler units is kept in service, with FGD and SCR installed.

The repowering option is based on the installation of three ‘F’ Class GTs with HRSGs supplying steam to one of the original steam turbine units. The performance is summarised in Table 6.1. With three gas turbines plus the repowered unit providing almost 1300 MW, only one of the remaining three units could be refurbished and operated with the result that the site would have a capacity of less than 2000 MW.

TABLE 6.1

PERFORMANCE IMPACT OF PLANT CONVERSION

Description	Net plant output MW	Net plant heat rate kJ/kWh	Net plant efficiency %	SOx mg/nm³	NOx mg/nm³	Cost €m
Reference plant	1835	9466	38.0	3,154	975	-
Replace boilers with GT/HRSG	1739	6486	49.5	0	50	590

The analysis shows that the repowering option has a relatively low capital cost and results in a significant increase in plant efficiency. However, it should also be noted that, despite the increased efficiency, the switch from lignite to natural gas results in a significant increase in fuel cost. This is considered further as part of the financial analysis.

7 REPOWER SITE

7.1 Introduction

Repowering of the site involves demolishing the plant and completely replacing the power plant equipment. This would typically involve replacing the entire plant with a conventional CCGT arrangement.

An alternative solution, which would make use of the existing fuel source, would be for an Integrated Gasification Combined Cycle plant (IGCC), however this technology is not considered to be sufficiently mature to be financially viable and has not therefore been considered further.

7.2 Implementation

To provide a comparison with the boiler replacement repowering, the same ‘F’ Class gas turbine model was used. Two power blocks each comprising two gas turbines, two HRSGs and 1 steam turbine produce a net plant output of 1779 MW.

The performance is summarised in Table 7.1:

TABLE 7.1

IMPACT OF SITE REPOWERING

Description	**Net plant output MW**	**Net plant heat rate kJ/kWh**	**Net plant efficiency %**	**SOx mg/nm³**	**NOx mg/nm³**	**Cost €m**
Reference Plant	1835	9466	38.0	3,154	975	-
New CCGT	1779	6199	58.1	0	50	873

As with the previous repowering example, the site repowering option has a relatively low capital cost and a significant increase in plant efficiency. However, once again the switch from lignite to natural gas results in a significant increase in fuel cost despite the increased efficiency. This is considered further as part of the financial analysis.

8 FINANCIAL ANALYSIS

A full financial analysis of the available options would be extremely complex and the analysis for each option could warrant a study in its own right. However, in order to allow a comparison to be made, some form of financial analysis is required so that the relative costs can be understood. A high-level comparison was therefore made, looking at the overall capital cost and costs associated with changes to plant performance. Other costs, such as operating and maintenance (O&M) costs and the cost of lost revenue during plant modifications, have not been considered at this stage.

The financial analysis was therefore based on the following three major cost components:

a. Change in revenue for generated output (expressed as a cost)
b. Change in fuel costs
c. Capital cost of modification

For this comparison, the revenue and fuel costs are expressed as net present value based on an assumed operating life of 25 years and a discount rate of 10 per cent. This therefore assumes that the existing plant has a remaining life of 25 years.

The results are summarised in Table 8.1. These show that the installation of FGD and SCR represents the lowest-cost option for the plant operator. This is as would be expected, as this option generally represents the lowest number of modifications to the existing plant. However, this is unlikely to give a true picture, as it is based on the assumption that the plant will operate for a further 25 years without any further remedial work or refurbishment and without any loss in availability. In reality, any plant in such a condition is likely to have already been modified and is not expected to have opted out under the LCPD regulations. This option is therefore considered as a benchmark for the other options and has been used as the base reference for the financial comparison, with all other costs being shown as additional to this amount.

The boiler replacement options represent the next lowest cost options, although the installation of a CFB boiler is significantly lower than that of a pulverised fuel type boiler. The main reason for this is that the CFB boiler does not require the addition of FGD and SCR, which not only reduces the capital cost but also leads to a higher output and efficiency. This is mainly due to the high auxiliary power demand of the FGD system, which gives a higher heat rate and a reduction in net output (and hence export power). Again, these options assume that the steam turbine plant is in good condition and suitable for continued operation.

Should the steam turbine plant also need to be replaced, the subcritical option appears to represent a lower cost solution than the supercritical option. However, with a low-cost fuel such as lignite (as used for the comparison), the fuel savings associated with the improved efficiency are not sufficient to cancel out the additional capital costs associated with the supercritical plant. This may not be the case where more expensive fuels such as black coal are concerned, and this would therefore need to be considered on a case by case basis.

The highest-cost options available to the plant operator are the two repowering options, which involve the introduction of gas turbines. Although the efficiencies are significantly improved in both cases, the high cost of gas results in the overall costs being much higher than for the other options. Repowering with gas fuelled plants should therefore be considered as the least-preferred option for the power plant operator and only for consideration where there are major problems with land availability and/or the prevailing planning and permitting processes.

TABLE 8.1

SUMMARY OF FINANCIAL ANALYSIS

	FGD/SCR	New subcritical boiler	New subcritical boiler and ST	New supercritical boiler and ST	New subcritical CFB boiler	Boiler replacement repowering	New CCGT
Capital cost (€m)	780	1616	1846	2389	1128	590	873
Increase in capital cost over FGD/SCR (€m)	0	836	1066	1609	348	-190	93
Total net electrical power output (MW)	1798	1811	1800	1785	1828	1739	1779
Reduction in electrical power output over FGD/SCR (MW)	0	-13	-2	13	-30	60	19
Annual electrical power generation (GWh)	13860	13961	13876	13760	14412	14079	14649
Reduction in annual electrical power generation over FGD/SCR (GWh)	0	-100	-15	100	-552	-219	-789
NPV of electricity sales (€m)	7297	7350	7305	7244	7587	7412	7712
Reduction in NPV of electrical sales over FGD/SCR (€m)	0	-53	-8	53	-290	-115	-415
Total net plant efficiency (%)	37.3%	37.9%	38.6%	41.0%	38.4%	49.5%	58.1%
Reduction in plant heat rate over FGD/SCR (%)	0.0%	1.8%	3.6%	10.1%	3.2%	33.0%	55.9%
Annual fuel cost (€m)	241	238	233	217	243	473	545
NPV of fuel cost (€m)	2188	2164	2115	1973	2205	4296	4946
Increase in lifetime fuel cost over FGD/SCR (€m)	0	-24	-74	-215	17	2108	2758
Lifetime cost relative to FGD/SCR (€m)	**0**	**759**	**985**	**1447**	**75**	**1803**	**2435**

9 COST SENSITIVITIES

9.1 General

The costs associated with any project are influenced by a large number of factors which can include geographic location, prevailing market conditions, site-specific plant design and site-specific risks. The type of fuel also has a major impact on the costs involved from both a capital and lifetime cost perspective. It would not be possible to analyse each of these in detail, although the main considerations are discussed in the following sections.

9.2 Fuel type

There are primarily two types of coal used for power generation within Europe (hard coal and brown coal) although for each type of fuel there can be wide variations in the quality and heat content available. The lower heating value of brown coal (lignite) requires much bigger boiler, fuel handling and ash handling and flue gas processing and conditioning plant than for hard coal, resulting in a much more expensive plant. The cost of a new hard coal plant is typically in the region of €1800/kW compared with the higher cost of €2300/kW for a similar sized plant using brown coal.

However, it should also be noted that the price of hard coal is generally 60 per cent to 70 per cent higher than that of brown coal, which results in much lower lifetime fuel costs for a lignite plant.

The composition of the specific fuel also has a major effect on the associated costs. Variations in the amounts of certain constituents can have an effect on the heating value of the coal and hence the required boiler size, although additional plant is often required for the removal of others. This is particularly the case with respect to sulphur, which has a direct impact on the SO_2 emissions.

The effect of sulphur content on the amount of SO_2 emitted is shown in the following table for various lignite and bituminous coals.

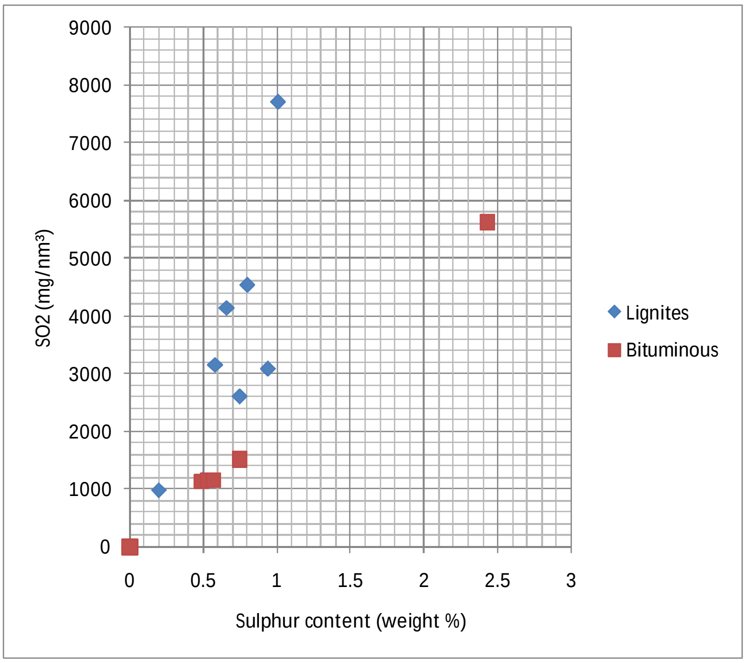

Figure 9.1 Effect of sulphur content on SO_2 emitted for various lignite and bituminous coals

It can be seen from the above that the amount of SO_2 emitted from different coals can vary significantly but also that for a given sulphur content, the SO_2 emitted is higher for lignite than for bituminous coals. The costs associate with upgrading the plant could therefore vary significantly from plant to plant.

9.3 Unit size

The size of each generating unit may also have an impact on the associated costs. Economies of scale are usually such that a single highly rated generating unit will usually have a lower cost than two generating units of half the size, due to certain fixed costs which are insensitive to scale. This can often lead to a higher relative cost for smaller units.

9.4 Market conditions

Market conditions can have a significant effect on pricing. The expected competition, the commercial risks, desired profit, currency exchange rates and general market workload can result in a wide variation in pricing for similar projects.

Prices of power plants due to begin operation between 2008 and 2020, obtained from Platts' database, show a large range in specific cost (660 Euro/kW – 1900 Euro/kW) for hard coal fired power plants, with little correlation between plant size and specific cost. For CCGT plant, the range in specific cost is even larger (140 Euro/kW – 1800 Euro/kW), again with correlation between plant size and specific cost. These very large ranges are not applicable to large plant in Europe. For the purpose of analysis, Parsons Brinckerhoff considers specific costs of around €1480/kW for hard coal fired plant and around €510/kW for CCGT plant to be a realistic estimate.

9.5 Geographic location

Costs are unlikely to be the same throughout Europe, although there are likely to be discrete areas (e.g. Scandinavia, Western Europe) where economies and costs are similar. Since most of the major equipment is likely to come from a limited number of international suppliers, the main difference in cost will be local labour and construction costs, local site conditions, and perception of risk.

Figure 9.2 shows European country construction cost indices, with UK average as the base (100 per cent). This shows the UK to be similar to Germany, although with a smaller range. Central and Eastern European countries generally have lower construction costs. For example the Czech Republic has an index range of 53 per cent-74 per cent with an average of 63.5 per cent when compared with the UK average. This factor would not be applied to the whole plant, and we would expect the overall plant costs to be around 80 per cent-90 per cent of the German-manufactured plants.

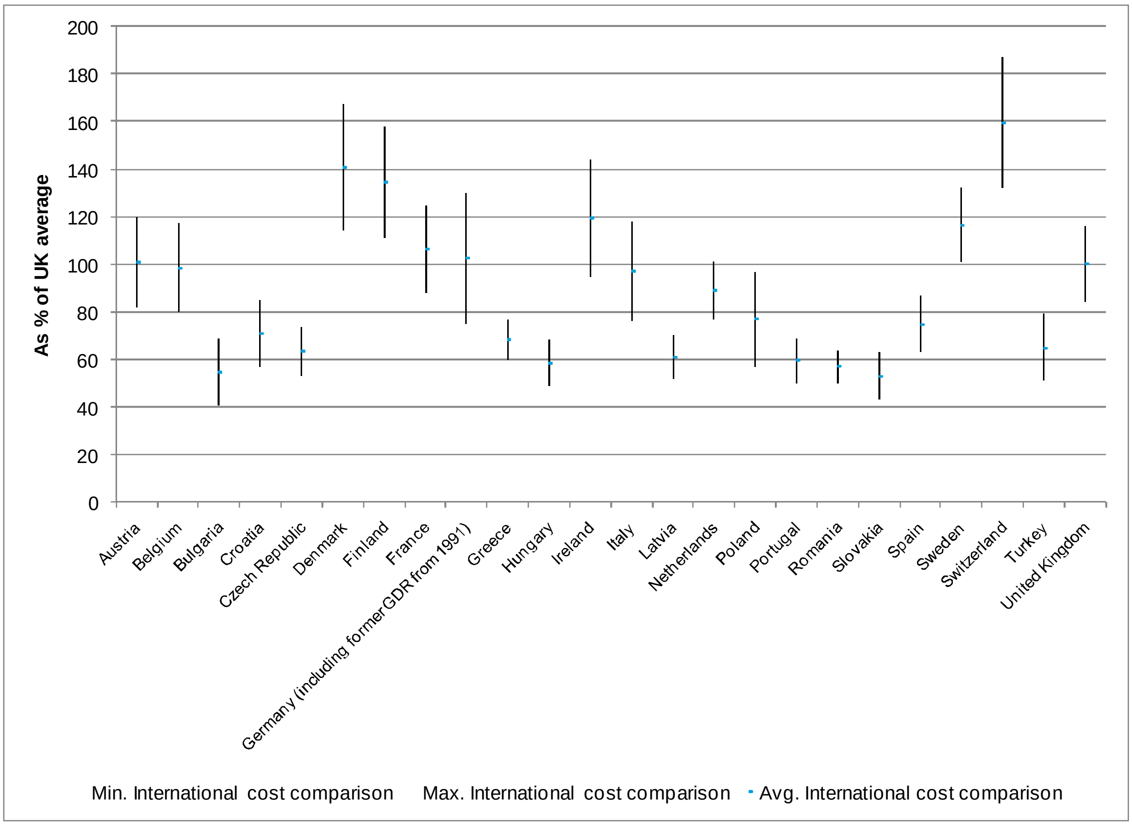

Figure 9.2 European construction cost indices[4]

9.6 Carbon pricing

The analysis does not consider the emissions of CO_2 as this is not covered by the IED regulations, however CO_2 emissions can have a significant impact on the financial evaluation of any project. Any reduction in CO_2 emitted from the plant is likely to have a financial benefit under the EU Emissions Trading Scheme (ETS) which will be dependent on the prevailing carbon price.

An example of this would be for the supercritical plant used in our analysis which has CO_2 emissions of 14 Million tonnes per year (based on a capacity factor of 90 per cent), which is approximately 1.5 Mt/yr lower than the simple SCR/FGD option. A carbon price of €20/t would lead to an additional cost benefit in the region of €30 million per annum for the supercritical option.

A similar situation exists with respect to the gas-fired options, which were not considered to be competitive within the earlier analysis. With the specific CO_2 emission rate reducing from 1 t/MWh for the lignite cases to 0.35 t/h for the natural gas cases, the gas turbine options may be more attractive,

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[4] http://www.building.co.uk/data/costs/international-costs/

especially if the carbon price is high. Table 9.3 shows the effect of CO_2 emissions with a price of €50/t. At this price, conversion to gas becomes a viable option.

TABLE 9.3

SUMMARY OF FINANCIAL ANALYSIS INCLUDING CARBON DIOXIDE COST

	FGD/SCR	New subcritical boiler	New subcritical boiler and ST	New supercritical boiler and ST	New subcritical CFB boiler	Boiler replacement repowering	New CCGT
Lifetime cost of change, excluding CO_2 cost (€m)	0	759	985	1,447	75	1,803	2,435
Total annual CO_2 production (Mt/y)	15.3	15.1	14.8	13.8	15.0	7.5	4.9
Annual CO_2 cost (€m)	765	756	739	690	751	376	243
Lifetime NPV of CO_2 (€m)	6,942	6,867	6,709	6,265	6,816	3,410	2,208
Lifetime cost of change, including CO_2 cost (€m)	0	684	752	771	-51	-1,729	-2,299

10 CONCLUSIONS AND RECOMMENDATIONS

Although based on a simplified approach and with a number of general assumptions, the results of the analysis clearly demonstrate that there are various options available to the opted-out power plant to allow continued operation beyond 2015. For the reference model under consideration, it was possible to meet the IED requirements for emissions for all of the considered options, although the actual extent of the modifications required will be specific for each plant under consideration.

There are a large number of financial variables that will also be specific for each plant, although the current price of gas is such that the upgrading of existing coal-fired plant is expected to be financially viable in a significant number of cases. Current power plant operators who have opted-out plant should therefore consider investigating the respective merits of their own plant in this regard.

In addition to the above, there is also the consideration of local planning and permitting processes. The availability of existing infrastructure, grid connections, cooling media and generating licences along with the long-term public acceptance of the facility may offer certain advantages over new greenfield developments. It is therefore likely that an upgraded or refurbished power plant could be put into operation much more quickly than a new build.

Of the options considered, the plant upgrading option (installation of FGD and SCR) appears to be the most cost-effective solution. However, this is based on the assumption that the plant is suitable for continued operation for a further 25 years without further major refurbishment work. In reality, any plant in such a condition is likely to have already been upgraded and is not expected to have opted out under the LCPD regulations.

Of the remaining options, the plant refurbishment options (replacement of boiler and/or turbine plant) appear to offer the best solutions, with the CFB boiler upgrade appearing to be the most financially attractive of all. Again, the CFB option assumes that the steam turbine and associated plant can operate without substantial refurbishment for a further 25 years. Supercritical CFB boiler upgrades were not included in this study because of the current limit on unit size, although it is likely that larger supercritical units will become available in the near future. Nevertheless, it is expected that supercritical CFB units will only compete with their subcritical counterparts where fuel prices are high or where carbon pricing becomes a factor.

The least attractive options appear to be those which involve the switch to natural gas (plant conversion and repowering). This is purely based on the high gas prices currently being experienced in the international market, although the consideration of carbon pricing could have a major influence in this regard. These options should not therefore be fully ruled out without giving due consideration to the effects of carbon pricing and the ongoing attitude to carbon trading within the political arena.

ACKNOWLEDGMENT

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