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IPPC Sector Guidance Note Combustion Activities

Integrated Pollution Prevention and Control (IPPC)



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Executive summary

Status of this Guidance

This guidance has been produced by the Environment Agency, along with the Scottish Environment Protection Agency (SEPA) and the Northern Ireland Environment and Heritage Service (EHS) - each referred to as “the Regulator” throughout this document. Please note the references to the document “Controls on Releases of Oxides of Sulphur and Nitrogen from Coal and Oil Fired Power Stations” at: <http://www.environment-agency.gov.uk/business/444304/444367/972464/?version=1&lang=e> is applicable to England and Wales only. Its publication follows consultation with industry, government departments and non-governmental organisations.

What is IPPC

Integrated Pollution Prevention and Control (IPPC) is a regulatory system that employs an integrated approach to control all environmental impacts of certain listed industrial activities. In the UK, the IPPC Directive is implemented through the English and Welsh, the Scottish, and the Northern Irish versions of the Pollution Prevention and Control (PPC) Regulations. It involves determination by the Regulator of the appropriate controls for those industries to protect all environmental media, through a single permitting process. To gain a PPC Permit, an Operator has to demonstrate in its Application, in a systematic way, that the techniques it is using or is proposing to use, both represent the use of Best Available Techniques (BAT), taking account of relevant local factors, and meet other relevant statutory requirements.

This Guidance and the BREF

Much UK Technical Guidance on what is BAT is based on the “BAT Reference documents” (“BREFs”) produced by the European Commission. BREFs are the result of exchanges of information between member states and industry, with most covering individual industrial sectors, and some (“horizontal” BREFs) covering cross-sectoral subjects. UK Technical Guidance Notes are designed to complement BREFs, and take into account information contained in relevant BREFs in setting out indicative BAT standards and expectations for England and Wales, Scotland and Northern Ireland.

The aims of this Guidance

The aim of the Guidance is to provide Operators and officers of the Regulator with advice on indicative standards of operation and environmental performance, relevant to the industrial sector concerned. It also aims (through linkage with the Permit Application Form template) to provide a clear structure and methodology for Operators to follow to demonstrate they have addressed adequately all aspects of the PPC Regulations and relevant aspects of other environmental Regulations. Also, by expressing BAT techniques as clear indicative standards wherever possible, it aims to minimise the effort involved for both Operator and Regulator in the permitting of an installation.

To further assist Operators and officers, separate horizontal guidance is available on a range of topics such as noise, odour, waste minimisation, monitoring, calculating stack heights and so on. Most of this guidance is available free through the Environment Agency, SEPA or EHS (Northern Ireland) websites (see [hyperlink](#) [elemtextonly](#)).

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1 Introduction

This Guidance has been produced by the Environment Agency for England and Wales, with the Scottish Environment Protection Agency (SEPA) and the Environment and Heritage Service (EHS) in Northern Ireland - each referred to as "the Regulator" in this document. Please note that "Controls on Releases of Oxides of Sulphur and Nitrogen from Coal and Oil Fired Power Stations" at: http://www.environment-agency.gov.uk/business/444304/444367/972464/?version=1&lang=_e is applicable to England and Wales only. Its publication follows consultation with industry, Government departments and non-governmental organisations.

It aims to provide Operators and the Regulator's officers with advice on indicative standards of operation and environmental performance relevant to the industrial sector concerned, to assist the former in the preparation of applications for PPC Permits and to assist the latter in the assessment of those Applications (and the setting of a subsequent compliance regime). The use of techniques quoted in the guidance and the setting of emission limit values at the benchmark values quoted in the guidance are not mandatory, except where there are statutory requirements from other legislation. However, the Regulator will carefully consider the relevance and relative importance of the information in the Guidance to the installation concerned when making technical judgements about the installation and when setting Conditions in the Permit, any departures from indicative standards being justified on a site-specific basis.

The Guidance also aims (through linkage with the Application Form or template) to provide a clear structure and methodology for Operators to follow to ensure they address all aspects of the PPC Regulations and other relevant Regulations, that are in force at the time of writing. Also, by expressing the Best Available Techniques (BAT) as clear indicative standards wherever possible, it aims to minimise the effort required by both Operator and Regulator to apply for and issue, respectively, a Permit for an installation.

1.1 UNDERSTANDING IPPC

Integrated Pollution Prevention and Control (IPPC) is a regulatory system that employs an integrated approach to control the environmental impacts of certain listed industrial activities. It involves determination by the Regulator of the appropriate controls for those industries to protect the environment, through a single permitting process. To gain a Permit, Operators have to demonstrate in their Applications, in a systematic way, that the techniques they are using or are proposing to use, are the Best Available Techniques (BAT) for their installation, and meet certain other requirements, taking account of relevant local factors.

The essence of BAT is that the techniques selected to protect the environment should achieve an appropriate balance between environmental benefits and the costs incurred by Operators. However, whatever the costs involved, no installation may be permitted where its operation would cause significant pollution.

IPPC operates under [The Pollution Prevention and Control Regulations](#) (for equivalent legislation in Scotland and N Ireland see [Appendix 2](#)). The three regional versions of the PPC Regulations implement in the UK the EC Directive on IPPC (96/61/EC). Further information on the application of IPPC/PPC, together with Government policy and advice on the interpretation of the English & Welsh Regulations, can be found in [IPPC: A Practical Guide](#) published by the Department for Environment, Food and Rural Affairs (Defra). Equivalent guidance on the Scottish Regulations is provided in [PPC Regulations: A Practical Guide \(Part A Activities\)](#), published by the Scottish Executive and SEPA. The Department of the Environment, Northern Ireland has published equivalent guidance on its Regulations.

Installation based, NOT national emission limits

The BAT approach of IPPC differs from regulatory approaches based on fixed national emission limits (except where General Binding Rules or Standard Permits are issued). The legal instrument that ultimately defines BAT is the Permit, and Permits can only be issued at the installation level.

Indicative BAT Standards

Indicative BAT standards are laid out in national guidance (such as this) and, where relevant, should be applied unless a different standard (including a stricter one) can be justified for a particular installation. BAT includes the technical components, process control, and management of the installation given in Section 2, and the benchmark levels for emissions identified in Section 3. Departures from those benchmark levels can be justified at the installation level by taking into account the technical characteristics of the installation concerned, its geographical location and the local environmental conditions. If any mandatory EU emission limits or conditions are applicable, they must be met, but BAT may go further (see "BAT and EQS" below).

Some industrial sectors for which national guidance is issued are narrow and tightly defined, whilst other sectors are wide and diffuse. This means that where the guidance covers a wide variety of processes, and individual techniques are not described in detail, the techniques (and their associated emission levels) which might constitute BAT for a particular operation, are more likely to differ, with justification, from the indicative BAT standards than would be the case for a narrow, tightly-defined sector.

BAT and EU limits or conditions

If any mandatory EU emission limits or conditions are applicable, they must be met as a minimum, even where Bat for the installation would not by itself require such standards.

BAT and EQS

The BAT approach complements, but differs fundamentally from, regulatory approaches based on Environmental Quality Standards (EQS). Essentially, BAT requires measures to be taken to prevent emissions - and measures that simply reduce emissions are acceptable only where prevention is not practicable. Thus, if it is economically and technically viable to reduce emissions further, or prevent them altogether, then this should be done irrespective of whether or not EQSs are already being met.

The BAT approach requires us not to consider the environment as a recipient of pollutants and waste, which can be filled up to a given level, but to do all that is practicable to minimise emissions from industrial activities and their impact. The BAT approach first considers what emission prevention can reasonably be achieved (covered by Sections 2 and 3 of this Guidance) and then checks to ensure that the local environmental conditions are secure (see [Section 4](#) of this Guidance and also Guidance Note [IPPC Environmental Assessments for BAT](#)). The BAT approach is therefore the more precautionary one because the release level achieved may be better than that simply required to meet an EQS.

Conversely, if the application of indicative BAT might lead to a situation in which an EQS is still threatened, a more effective technique is required to be BAT for that installation. The Regulations allow for expenditure beyond indicative BAT where necessary, and, ultimately, an installation will only be permitted to operate if it does not cause significant pollution.

Further advice on the relationship between BAT, EQSs and other related standards and obligations is given in [IPPC: A Practical Guide](#), its Scottish and Northern Irish equivalents, and also in Section 3.

The assessment of indicative BAT takes place at a number of levels. At the European level, the European Commission issues a "BAT reference document" (BREF) for each main IPPC sector. It also issues "horizontal" BREFs for a number of general techniques which are relevant across a series of industrial sectors. The BREFs are the result of an exchange of information between regulators, industry and other interested parties in Member States. Member States should take them into account when determining BAT, but they are allowed flexibility in their application. UK Sector Guidance Notes like this one take account of information contained in relevant BREFs and set out current indicative standards

and expectations in the UK. At national level, techniques that are considered to be BAT should represent an appropriate balance of costs and benefits for a typical, well-performing installation in the sector concerned. They should also be affordable without making the sector as a whole uncompetitive, either within Europe or world-wide.

Assessing BAT at the Installation level

When assessing applicability of sectoral indicative BAT standards at the installation level, departures may be justified in either direction. Selection of the technique which is most appropriate may depend on local factors and, where the answer is not self-evident, an installation-specific assessment of the costs and benefits of the available options will be needed. The Regulator's guidance [IPPC Environmental Assessments for BAT](#) and its associated software tool may help with the assessment. Individual installation or company profitability (as opposed to profitability of the relevant sector as a whole) is not a factor to be considered, however.

In the assessment of BAT at the installation level, the cost of improvements and the timing or phasing of that expenditure, are always factors to be taken into account. However, they should only be major or decisive factors in decisions about adopting indicative BAT where:

- the installation's technical characteristics or local environmental conditions can be shown to be so different from those assumed in the sectoral assessment of BAT described in this guidance, that the indicative BAT standards may not be appropriate; or
- the BAT cost/benefit balance of an improvement only becomes favourable when the relevant item of plant is due for renewal/renovation (e.g. change to a different design of furnace when the existing furnace is due for a rebuild). In effect, these are cases where BAT for the sector can be expressed in terms of local investment cycles; or
- a number of expensive improvements are needed. In these cases, a phasing programme may be appropriate - as long as it is not so drawn out that it appears to be rewarding a poorly performing installation.

In summary, departures by an individual installation from indicative BAT for its sector may be justified on the grounds of the technical characteristics of the installation concerned, its geographical location and the local environmental conditions - but not on the basis of individual company profitability, or if significant pollution would result. Further information on this can be found in [IPPC: A Practical Guide](#) and [IPPC Part A\(1\) Installations: Guide for Applicants](#), or the equivalent Scottish or Northern Irish Guidance.

Innovation

The Regulators encourage the development and introduction of innovative techniques that advance indicative BAT standards criteria, ie. techniques which have been developed on a scale which reasonably allows implementation in the relevant sector, which are technically and economically viable and which further reduce emissions and their impact on the environment as a whole. One of the main aims of the PPC legislation is continuous improvement in the overall environmental performance of installations as a part of progressive sustainable development. This Sector Guidance Note describes the indicative BAT standards at the time of writing but Operators should keep up-to-date with improvements in technology - and this Guidance Note cannot be cited as a reason for not introducing better available techniques. The technical characteristics of a particular installation may also provide opportunities not foreseen in the Guidance, and as BAT is determined at the installation level (except in the case of General Binding Rules (GBRs)), it is a requirement to consider these even where they go beyond the indicative Standards.

New Installations

Indicative BAT standards apply, where relevant, to both new and existing installations, but it will be more difficult to justify departures in the case of new installations (or new activities in existing installations) - and for new activities, techniques which meet or exceed indicative BAT requirements should normally be in place before operations start.

Existing installations

For an existing installation, it may not be reasonable to expect compliance with indicative BAT standards immediately if the cost of doing so is disproportionate to the environmental benefit to be achieved. In such circumstances, operating techniques that are not at the relevant indicative BAT standard may be acceptable, provided that they represent what is considered BAT for that installation and otherwise comply with the requirements of the Regulations. The determination of BAT for the installation will involve assessment of the technical characteristics of the installation and local environmental considerations, but where there is a significant difference between relevant indicative BAT and BAT for an installation, the Permit may require further improvements on a reasonably short timescale.

Upgrading Timescales

Where there are departures from relevant indicative BAT standards, Operators of existing installations will be expected to have upgrading plans and timetables. Formal timescales for upgrading will be set as Improvement Conditions in the Permits. See [Section 1.4.2](#) for more details.

1.2 MAKING AN APPLICATION

A satisfactory Application is made by:

- addressing the issues in Sections 2 and 3 of this guidance;
- assessing the environmental impact described in Section 4 (and in England and Wales [Environmental Assessment and Appraisal of BAT \(IPPC H1\)](#));
- demonstrating that the proposed techniques are BAT for the installation.

In practice, some Applicants have submitted far more information than was needed, yet without addressing the areas that are most important - and this has led to extensive requests for further information. In an attempt to focus application responses to the areas of concern to the Regulator, Application forms (templates) have been produced by the Environment Agency, by SEPA and by EHS in N Ireland. In addition, as the dates for application have approached, the operators in most industrial sectors in England and Wales have been provided with Compact Discs (CDs) which contain all relevant Application Forms, technical and administrative guidance, BREFs and the charging scheme (known as EOPRA), hyper-linked together for ease of use.

For Applicants with existing IPC Authorisations or Waste Management Licences, the previous applications may provide much of the information for the PPC application. However, where the submitted Application refers to information supplied with a previous application the Operator will need to send fresh copies - though for many issues where there is a tendency for frequent changes of detail (for example, information about the management systems), it will be more appropriate simply to refer to the information in the Application and keep available for inspection on site, up-to-date versions of the documents.

For further advice see [IPPC Part A\(1\) Installations: Guide for Applicants \(for England and Wales\)](#) or [PPC Part A Installations: Guide for Applicants \(for Scotland\)](#) or the equivalent Northern Ireland guide for Applicants.

1.3 INSTALLATIONS COVERED

This Guidance relates to installations containing the activities listed below, as described in Part A(1) of Schedule 1 to [The Pollution Prevention and Control Regulations](#). The schedules of listed activities are slightly different in Scotland and Northern Ireland so for their equivalent Regulations see [Appendix 2](#)

The installations covered within the scope of this guidance include:

Section 1.1 Combustion Activities, Part A(1) :

- (a) Burning any fuel in an appliance with a rated thermal input of 50 megawatts or more.
- (b) Burning any of the following fuels in an appliance with a rated thermal input of 3 megawatts or more, but less than 50 megawatts, unless the activity is carried out as part of a Part A(2) or B activity -
 - (i) waste oil;
 - (ii) recovered oil;
 - (iii) any fuel manufactured from, or comprising, any other waste.

Selected activities of Section 1.2 Part A(1) :

- (e) Producing gas from oil or other carbonaceous material or from mixtures thereof, other than from sewage, unless the production is carried out as part of an activity which is a combustion activity (whether or not that combustion activity is described in Section 1.1).
- (j) Activities involving the pyrolysis, carbonisation, distillation, liquefaction, gasification, partial oxidation, or other heat treatment of coal (other than the drying of coal), lignite, oil, other carbonaceous material or mixtures thereof otherwise than with a view to making charcoal.

Landfill gas engines

Operators of Landfill gas engines should refer to LFTGN 6 Guidance on gas treatment technologies for Landfill Gas Engines

http://www.environment-agency.gov.uk/commondata/acrobat/lftgn06_treatment_936556.pdf

AGGREGATION

The regulations require that, for the purposes of paragraph a) above, where two or more appliances with an aggregated rated thermal input of 50MW or more are operated on the same site by the same operator those appliances are treated as a single appliance with a rated thermal input of 50MW or more.

For the purposes of combustion plant this aggregation rule would normally include all boilers, including those rated at below <3 MWth and those designated as standby plant.

Note that incineration activities are described in, Incinerator Sector Guidance Note IPPC S5.01 http://www.environment-agency.gov.uk/commondata/acrobat/incin_bat_guidance_854788.pdf but that co-incineration activities, as defined under the Waste Incineration Directive (WID) fall under this guidance. Details concerning the application of the WID in this Sector is summarised in Tables 1.3.1 and 1.3.2.

The installation will also include **associated activities** which have a technical connection with the main activities and which may have an effect on emissions and pollution, as well as the main activities described above. These may involve activities such as:

- the storage and handling of raw materials; the storage and despatch of finished products, waste and other materials;

- the control and abatement systems, where not an integral part of the listed activity, for emissions to all media;
- waste treatment or recycling.

Environment Agency advice on the composition of English or Welsh installations and which on-site activities are to be included within it (or them) is given in its guidance document **[IPPC Regulatory Guidance Series No.5 - Interpretation of "Installation" in the PPC Regulations](#)**. Operators are advised to discuss the composition of their installations with the Regulator before preparing their Applications.

Note that This table is not applicable in Scotland. Please contact SEPA to discuss combustion plant regulatory issues for Scotland							
Table 1.3.1 Combustion, gasification plus combustion or pyrolysis (where gas is produced) plus combustion							
		<0.4MWth	0.4 - 3MWth	3 - 20MWth	20 - 50MWth	>50MWth	
Material Processed		See note 1					
Fuel not comprising Waste eg coppiced wood		Not regulated under PPC	Not regulated under PPC	Not regulated under PPC	1.1 B(a)	1.1A(1)(a)	WID DOES NOT APPLY
WID Exempt waste eg biomass		Not regulated under PPC	1.1 B (c)	1.1A(1)(b)(unless part of a part A(2) or B activity)	1.1A(1)(b)(unless part of a part A(2) or B activity)	1.1A(1)(a)	
Non hazardous waste	Incineration (Primary purpose is destruction of waste)	5.1A(1)(c) if >= 1t/hr 5.1A(2)(a) if < 1t/hr	5.1A(1)(c) if >= 1t/hr 5.1A(2)(a) if < 1t/hr	5.1A(1)(c) if >= 1t/hr 5.1A(2)(a) if < 1t/hr	5.1A(1)(c) if >= 1t/hr 5.1A(2)(a) if < 1t/hr	5.1A(1)(c) if >= 1t/hr 5.1A(2)(a) if < 1t/hr	WID DOES APPLY
Non hazardous waste	Co-incineration (Primary purpose is generation of energy)	5.1A(2)(b)	5.1A(2)(b)	1.1A(1)(b)(unless part of a part A(2)activity)	1.1A(1)(b)(unless part of a part A(2) activity)	1.1A(1)(a)	
Hazardous waste	Incineration (Primary purpose is destruction of waste)	5.1A(1)(a)	5.1A(1)(a)	5.1A(1)(a)	5.1A(1)(a)	5.1A(1)(a)	
Hazardous waste	Co-incineration (Primary purpose is generation of energy)	5.1A(1)(b)	5.1A(1)(b)	1.1A(1)(b)	1.1A(1)(b)	1.1A(1)(a)	

Note:1 WID Guidance(ref) excludes certain small waste burners and space heaters or other waste oil burners. In these cases 1.1 B (b) or (c) may apply dependent on individual or aggregated capacity

PLEASE NOTE This table is not applicable in Scotland. Please contact SEPA to discuss combustion plant regulatory issues for Scotland							
Table 1.3.2 Pyrolysis where gas is not produced							
		<0.4MWth	0.4 - 3MWth	3 - 20MWth	20 - 50MWth	>50MWth	
Material Processed							
Material not comprising Waste eg coppiced wood		1.2A(1)(j)	1.2A(1)(j)	1.2A(1)(j)	1.2A(1)(j)	1.2A(1)(j)	WID DOES NOT APPLY
WID Exempt waste eg biomass		1.2A(1)(j)	1.2A(1)(j)	1.1A(1)(b)(unless part of a part A(2) or B activity)	1.1A(1)(b)(unless part of a part A(2) or B activity)	1.1A(1)(a)	
Non hazardous waste	Incineration (Primary purpose is destruction of waste)	5.1A(1)(c) if \geq 1t/hr 5.1A(2)(a) if < 1t/hr	5.1A(1)(c) if \geq 1t/hr 5.1A(2)(a) if < 1t/hr	5.1A(1)(c) if \geq 1t/hr 5.1A(2)(a) if < 1t/hr	5.1A(1)(c) if \geq 1t/hr 5.1A(2)(a) if < 1t/hr	5.1A(1)(c) if \geq 1t/hr 5.1A(2)(a) if < 1t/hr	WID DOES APPLY
Non hazardous waste	Co-incineration (Primary purpose is generation of energy)	5.1A(2)(b)	5.1A(2)(b)	1.1A(1)(b)(unless part of a part A(2)activity)	1.1A(1)(b)(unless part of a part A(2)activity)	1.1A(1)(a)	
Non hazardous waste	Material products- No incineration of any products locally or remotely	1.2A(1)(j)	1.2A(1)(j)	1.2A(1)(j)	1.2A(1)(j)	1.2A(1)(j)	WID DOES NOT APPLY
Hazardous waste	Incineration (Primary purpose is destruction of waste)	5.1A(1)(a)	5.1A(1)(a)	5.1A(1)(a)	5.1A(1)(a)	5.1A(1)(a)	WID DOES APPLY
Hazardous waste	Co-incineration (Primary purpose is generation of energy)	5.1(A)1(b)	5.1(A)1(b)	1.1A(1)(b)	1.1A(1)(b)	1.1A(1)(a)	
Hazardous waste	Material products- No incineration of any products locally or remotely	1.2A(1)(j)	1.2A(1)(j)	1.2A(1)(j)	1.2A(1)(j)	1.2A(1)(j)	WID DOES NOT APPLY

1.4 TIMESCALES

1.4.1 Permit review periods

Permits are likely to be reviewed as follows:

- for individual activities not previously subject to regulation under IPC or Waste Management Licensing, a review should be carried out within four years of the issue of the PPC Permit
- for individual activities previously subject to regulation under IPC or Waste Management Licensing, a review should be carried out within six years of the issue of the IPPC Permit

However, where discharges of Groundwater List I or List II substances have been permitted, or where there is disposal of any matter that might lead to an indirect discharge of any Groundwater List I or II substance, a review must be carried out within four years as a requirement of the Groundwater Regulations.

These periods will be kept under review and, if any of the above factors change significantly, they maybe shortened or extended.

1.4.2 Upgrading timescales for existing plant

Unless subject to specific conditions elsewhere in the Permit, upgrading timescales will be set in the Improvement Programme of the Permit, having regard to the criteria for improvements in the following two categories:

1 Standard "good-practice" requirements, such as, management systems, waste, water and energy audits, bunding, housekeeping measures to prevent fugitive or accidental emissions, good waste handling facilities, and adequate monitoring equipment. Many of these require relatively modest capital expenditure and so, with studies aimed at improving environmental performance, they should be implemented as soon as possible and generally well within 3 years of issue of the Permit.

2 Larger, more capital-intensive improvements, such as major changes to reaction systems or the installation of significant abatement equipment. Ideally these improvements should also be completed within 3 years of Permit issue, particularly where there is considerable divergence from relevant indicative BAT standards, but where justified in objective terms, longer time-scales may be allowed by the Regulator.

Local environmental impacts may require action to be taken more quickly than the indicative timescales above, and requirements still outstanding from any upgrading programme in a previous permit should be completed to the original time-scale or sooner. On the other hand, where an activity already operates to a standard that is close to an indicative requirement a more extended time-scale may be acceptable. Unless there are statutory deadlines for compliance with national or international requirements, the requirement by the Regulator for capital expenditure on improvements and the rate at which those improvements have to be made, should be proportionate to the divergence of the installation from indicative standards and to the environmental benefits that will be gained.

The Operator should include in the Application a proposed programme in which all identified improvements (and rectification of clear deficiencies) are undertaken at the earliest practicable opportunities. The Regulator will assess BAT for the installation and the improvements that need to be made, compare them with the Operator's proposals, and then set appropriate Improvement Conditions in the Permit.

1.4.3 Stand-by and Low Utilisation Plant

For standby or low utilisation plant that are used for a limited number of hours during any one year (less than 1000 hours), the extent of upgrading required will be dependent on the actual operational hours (Operational hours in this context normally means hours where fuel is being burnt but excludes start up and shut down) anticipated and the impact on the local environment. Such issues should be considered on a site-specific basis. Ordinarily, conditions should be imposed in the permit placing a constraint on the hours of operation of such plant

1.5 KEY ISSUES

The note identifies the key issues for the combustion sector and focusses on the techniques to prevent pollution associated with them.

The key issues for the combustion plant sector, with regards to releases to air, are the emissions of sulphur dioxide, nitrogen oxides and particulate matter, particularly from solid fuel fired plants. Trace substances, such as heavy metals and dioxins may be present in exhaust stacks. The environmental impacts of significance are likely to be on ground level air quality which should be addressed in the Operator's assessment of environmental impact.

Global warming will be a significant impact that should be addressed under climate change levy agreements and/or the Greenhouse Gas Emissions Trading Regulations. In this context, PPC recognises the benefits of good combustion practice, such as CHP.

Large combustion plants are operated to standards under the European Commission's Large Combustion Plant Directive and Emissions Trading Directive as transposed in England and Wales through the Greenhouse Gases Emissions Trading Scheme Regulations, 2003.

For any combustion activity, there is an inter-relation between the CO concentration, NOx concentration, carbon in ash and thermal efficiency. Consequently, combustion should be controlled to provide an optimum compromise between these factors.

There is increasing interest within this sector to burn alternative fuels. Where these fuels are classified as wastes, then plants burning or intending to burn these fuels will be classified as co-incineration plants under the European Commission's Waste incineration Directive and the relevant emission limits given within this directive will apply.

The Environment Agency for England and Wales has developed a Protocol For The Burning Of Biomass Fuels in Power Stations. It defines biomass as stated within Article 2.11 of the Large Combustion Plant Directive. Such materials can be an attractive option for Operators seeking to meet their Renewables Obligation. Applications to burn biomass for electricity generation in England and Wales comply with the requirements of this Protocol..

The use of waste derived fuels, for example solvents, plastics, paper or residues from mechanical and biological treatment facilities (MBTF) will be subject to the additional requirements of the Waste Incineration Directive for co-incineration plants.

Operators are advised to discuss the use of alternative fuels with the Regulator to establish whether it is classified as "waste" before preparing an application.

The key issues with regards to releases to land relate to the disposal of ash residues and air pollution control equipment residues. Where possible, Operators should find alternatives to disposal for residues from flue gas desulphurisation plants e.g. in the manufacture of gypsum and pulverised fuel ash (PFA) e.g. for use in cement manufacture.

The Landfill Directive may also require specialist pre-treatment of residues before they can be landfilled.

The impacts of these residues are potentially on ground and surface water quality and fugitive low-level releases of dust. These should all be addressed in the Operator's assessment of environmental impact.

Key releases to water will predominately include the discharge of cooling water and may also include aqueous discharges from air pollution control equipment.

1.6 SUMMARY OF RELEASES

TABLE 1: Potential release routes for boilers and furnaces

SOURCE RELEASES	Substances															
	Particulate Matter	Oxides of Sulphur	Oxides of Nitrogen	Oxides of Carbon	Hydrogen chloride/fluoride	Volatile organic compounds	Suspended solids	Acids/alkalis/salts etc	Metals and their salts	Chlorine (as Hypochlorite)	Sulphates	Chlorides	Mercury and/or cadmium	Organic compounds	PAHs	Dioxins
To: <u>Air</u> <u>Water</u> <u>Land</u>																
A W L																
Fuel storage and handling	A					A								W		
Water treatment								W		W		W	W	W	W	
Boiler blowdown							W	W						W		
Flue Gas	A	A	A	A	A	A			A			A	A	A	A	A
Flue gas treatment							W		W L		W	W	W	W		
Furnace bottom ash/clinker	A								L							L
Fly ash	A								A							L
Site drainage including rainwater							W		W					W		
Waste water treatment							W	W						W		
Cooling water blowdown							W			W	W	W	W			
Cooling tower exhaust						A										

Note: The release of relatively warm water, for example from cooling water discharges, to the aquatic environment can have a detrimental effect on the local aquatic ecosystem.

TABLE 2: Potential Release Routes for Gas Turbines

SOURCE RELEASES To: Air Water Land A W L	Substances						
	Particulate Matter	Oxides of Sulphur	Oxides of Nitrogen	Oxides of Carbon	Organic Compounds	Suspended Solids	Acids / alkalis / salts etc
Gas turbine exhaust	A	A	A	A	A		
Fuel storage and handling					AWL		
Water treatment					W	W	W
Boiler blowdown						W	W

Note: The release of relatively warm water, for example from cooling water discharges, to the aquatic environment can have a detrimental effect on the local aquatic ecosystem.

TABLE 3: Potential release routes for CI engines

SOURCE RELEASES To: <u>Air</u> <u>Water</u> <u>Land</u> A W L	Substances												
	Particulate Matter	Oxides of Sulphur	Oxides of Nitrogen	Oxides of carbon	Organic compounds	Acids/alkalis/salts etc	Hydrogen chloride/fluoride	Volatile organic compounds	Metals and their salts	Chlorine(as hypochlorite)	Mercury and/or cadmium	PAHS	Dioxins
Fuel storage and handling					W			A					
Water treatment	W							W		W			
Exhaust gas	A	A	A	A	A		A	A	A		A	A	
Exhaust gas treatment	W				W			W L		W			
Site drainage including rainwater	W				W								
Waste water treatment	W				W								
Cooling water blowdown	W				W	W		W	W	W			
Cooling tower exhaust					W			A					

Note: The release of relatively warm water, for example from cooling water discharges, to the aquatic environment can have a detrimental effect on the local aquatic ecosystem.

TABLE 4: Potential release routes for Carbonisation

SOURCE RELEASES	Substances													
	Particulate Matter	Hydrogen Sulphide	Oxides of Sulphur	Hydrogen Chloride	Oxides of Nitrogen	Oxides of carbon	Dioxins	Benzene	Phenol	PAHs	Organic compounds	Tar Fume	Heavy Metals	Ammonia
To: <u>Air</u> <u>Water</u> <u>Land</u>														
A W L														
Smokeless fuel LTC Processes														
Battery & boiler flue gases & flaring	A		A	A	A	A	A							
Battery abatement chimneys	A							A	A	A	A	A		
Screen abatement stack	A							A		A	A	A		
Battery charging/discharging, seal leaks & green gas maintenance releases		A						A	A	A	A			
Effluent discharges/surface water	W								W		W		W	
Storage tanks		A						A	A	A	A	A		A
Other smokeless Fuel Processes														
Combustor/incinerator flue gases	A		A	A	A	A	A							
Dryer vents (direct)	A		A	A	A									
Dryer vents (indirect)	A													
Effluent discharges/surface water	W													
Carbon Black														
Boiler / CHP flue vents	A	A	A		A	A					A			
Dryer flue gas	A	A	A		A	A					A			
Process/purge/dust filters	A										A			
Effluent discharges/surface water	W												W	

TABLE 5: Potential release routes for Gasification

SOURCE RELEASES	Substances												
	To: <u>Air</u>	<u>Water</u>	<u>Land</u>	Particulate Matter	Oxides of Sulphur	Oxides of Nitrogen	Oxides of carbon	Organic compounds	Acids/alkalis/salts etc	Volatile organic	Hydrogen Sulphide	Ammonia	Metals and their salts
	A	W	L										
Fuel storage and handling	A							A W L		A			
Water treatment		W						W	W				W
Slag/Ash Handling	A												
Gas Handling & Treatment	A	A	A	A	A	A	A			A	A	A	
Salt Recovery	A							L W					
Wastewater Treatment		W				A		W	W			W	
Site drainage (incl Rainwater)		W						W					
Boiler Blowdown		W							W				W

1.7 TECHNICAL OVERVIEW

1.7.1 General

The combustion sector covers a range of different combustion systems techniques, suited to different fuels. This section describes the main types of processes for the combustion of solid, liquid and gaseous fuels of plant covered by this Note. These processes have been summarised in Table 6 (below) and brief descriptions follow. Descriptions of BAT control measures are included in Section 2 of this guidance note. Further detailed descriptions of the activities and processes are given in EU Reference Document on the Best Available Techniques for Large Combustion Plants.

Table 6: Combustion Processes

Technique/Technology	Process Plant Type	Feedstock
Combustion	Fixed Grate Systems	S (L/G)
	Moving Grate systems	S (L/G)
	Atmospheric Fluidised Bed	S (L/G)
	Pressurised Fluidised Bed	S (L/G)
	Pulverised Fuel	S
Turbine Engines	Industrial	G/L
	Aero	G/L
Reciprocating Engines	Spark Ignition	G/L
	Compression Ignition	G/L
Carbonisation	Low Temperature Carbonisation	S
	Smokeless Fuel Briquettes	S
	Activated Carbon	S
	Carbon Black	S/L
Gasification/Pyrolysis		S/L
Integrated Systems	CHP	S/L/G
	IGCC	S/L/G

Feedstock (S) – Solid, (L) – Liquid, (G) - Gaseous

1.7.2 Fuel Storage and Preparation

1.7.2.1 Solid

Materials are usually stored in stockpiles. These piles may vary in size depending on the required level of supply security required and transport logistics. For bulk materials, such as coal, the material is stored in the open, whereas for biomass, covered or closed storage silos should be considered.

Where raw fuels may vary in combustion characteristics, the materials may be blended to achieve a consistent fuel quality. Material stored in the open, or biomass still containing moisture should be dried before use wherever practical.

As a final fuel pre-treatment stage, fuels may require sizing. Grinding, shredding, pulverising and classifying methods may be required, depending on the combustion system

1.7.2.2 Liquid

Fuel oil is stored in vertical storage tanks, which should be contained within an appropriately sized impervious bund. Floating roof and vented tanks are commonly used. Where fuel viscosity needs to be controlled, the tanks may be fitted with heaters. In such circumstances the tanks should be insulated.

1.7.2.3 Gaseous

Gaseous fuels are normally supplied directly by pipeline and onsite storage is not commonly practised.

1.7.3 Large Boilers and Furnaces

1.7.3.1 Process Overview

Solid fuels

Grate firing

Although generally superseded by fluidized bed for larger applications, grate firing may still be used for small combustion applications, such as combustion of biomass or certain coals. Combustion conditions are not as well controlled as in other systems as the combustion chemistry and temperature can vary considerably across the grate. Grates may be fixed, sloped or traveling

Stoker firing (moving grate)

Stoker, or moving grate, combustion systems are used to burn coarse solid materials and are generally used for furnaces in the 20 to 100MW(th) range. The material sits on top of the moving grate, through which air passes. Most of the ash/clinker falls off the end of the grate and is easily handled or falls through the grate and is collected in a pit. Smaller quantities of fine solids can be entrained with the combustion gases when compared with other combustion technologies.

There is potential for modest control of the release of oxides of sulphur by the injection of a sorbent such as limestone (or dolomite) into the combustion chamber. There is however, limited experience that indicates this technique may not be appropriate for all existing boilers. Emissions of NO_x (nitric oxide [NO] and nitrogen dioxide [NO₂]) from moving grate stokers are inherently low, because the temperature of combustion is low and combustion is naturally 'staged' within the fuel bed as it moves along the grate. Further abatement is unlikely to be needed.

No special fuel preparation within the process is needed in most cases. Ash and clinker disposal at a licensed waste disposal site is necessary if the quality is too variable or the quantity surplus for the use in the building and construction industry. Aqueous effluent from ash quenching should be minimised by recirculating the quench liquors and only purging the minimum required.

Pulverised fuel firing

This technique is well established for all sizes of boiler above 50 MW(th). Multiple burners are used for large plants. Relatively rapid load adjustments are possible. Combustion efficiency is high and less carbon remains in the ash than with Stoker firing. The fly ash is very fine and the prevention of fugitive emissions requires containment of handling and storage systems or the use of dust suppression techniques, for example wetting. Pulverised fuel ash and furnace bottom ash may be used in the construction industry and elsewhere.

Coal may need to be carefully blended to ensure uniformity and is finely ground in large mills. These mills require regular maintenance in order to achieve the design milling performance and to ensure fugitive dust emissions are not created.

There is generally a higher generation of nitrogen oxides than with stoker firing and the amount is dependent on the type of burner and boiler design as well as the nitrogen content and other characteristics of the fuel.

The particulate matter, of which 80-90% is entrained in the flue gases leaving the boiler, has a wide range of particle sizes. In such cases, high efficiency particulate matter removal plant, for example electrostatic precipitators or bag filters, is required.

The aim should be to produce pulverised fuel ash with a low carbon content that can be used elsewhere, rather than requiring disposal to landfill. It is recognised that in some circumstances this is not always readily achievable e.g. at installations burning low volatile coals. PFA has a variety of applications and the material should be handled accordingly. For instance, where ash is used in cement, it should be handled as a "dry" powder using pneumatic and enclosed conveyors for transport and silos for intermediate storage prior to dispatch off-site in bulk solids tankers. For other applications, it may be appropriate to 'condition' the material by the addition of water to facilitate transport and prevent dust blow.

Where the quantity of PFA produced is greater than demand, the surplus material will require disposal at a licensed landfill site. Depending on local circumstances, it is either landfilled in a conditioned form or transported hydraulically to lagoon sites. Liquid effluent from ash handling can be minimised if conventional ash lagoons and hydraulic transport techniques are not used.

Furnace bottom ash is quenched with water sprays and washed into ash pits. The water used should be recirculated and purging should be minimised (where sea water is used a once-through system may be used to prevent scaling and corrosion). The ash itself is recovered from the pits and can be used in the construction industry.

Atmospheric fluidised bed combustion

Bubbling shallow bed technology is used for individual units up to about 50 MW(th). Particulate solids emissions are high and high efficiency removal equipment such as bag filters or electrostatic precipitators are required. Bubbling beds are moderate nitrogen oxides emitters and there is limited scope to modify existing plant to reduce nitrogen oxides emissions at reasonable cost. There is potential for control of emissions of sulphur dioxide by sorbent additions to the bed itself.

Circulating fluidised bed combustors (CFBC) are now widely used for plant in excess of about 40 MW(th). Commercial units up to 550 MW(th) are in use worldwide. Emissions of NO_x are inherently lower with CFBC operations than with pulverised fuel systems. However, nitrous oxide [N₂O] emissions are higher from this type of plant than from a pulverised fuel plant and nitrous oxide is a potent greenhouse gas. Particulate solids emissions are high and necessitate the use of high efficiency removal equipment downstream of the combustor.

There is potential for good in-bed sulphur control in fluidised bed combustion systems. The reduction in oxides of sulphur releases can be 90% or more. Free lime is present in the ash produced.

Pressurised fluidised bed combustion

Pressurised fluidised bed combustion (PFBC) plants are now available. Plant up to 400 MW(th) is in operation worldwide. Pressurised fluidised beds have a higher net thermal efficiency than atmospheric fluidised beds and conventional combustion plant for electricity generation, especially conventional plant fitted with flue gas desulphurisation.

Emissions of NO_x are inherently lower than with conventional fuel systems. Ammonia can be directly injected (a form of SNCR) into the furnace to reduce NO_x further, without using

add-on back-end catalysts (ie SCR), if required. Sulphur oxides levels are also inherently low due to the use of sorbent (limestone or dolomite), which also helps form the fluidised bed. Sulphur removal levels of 90% or more have been achieved. The pressurised process has an advantage over atmospheric fluidised beds in that the ash released is not calcined, so that calcium oxide levels are very low and ash handling provides less of a problem.

Liquid Fuels

These include all types of oil and emulsions, for example bitumen emulsions and the firing of liquefied petroleum gas (LPG) where it is fed to the burner as a liquid and not first vaporized.

The in-furnace techniques for prevention or minimization of releases of NO_x and particulates are based on burner design, the method of atomization and the control of primary, secondary and tertiary air. A control loop system is required to govern the air and fuel supply and is significant in air pollution control. Such techniques may not be practical for small installations using compact, high thermal rating combustion chambers.

Filtration plant may be necessary for the removal of particulate matter from certain liquid fuels. It is important that the atomisation of oil fuels is efficient and the primary consideration will be the viscosity of the fuel fed to the burners. The combustion of heavier grades of oil may also be improved by the addition of dispersive reagents. Oil (including bitumen) emulsions and many heavy fuel oils have high sulphur contents and may have high vanadium and nickel contents. Their use directly as fuels will normally require that abatement plant is used to minimize sulphur dioxide and heavy metals emissions.

The use of oil fuels containing sulphur will result in some sulphur trioxide releases, in addition to sulphur dioxide. Where low sulphur oils (below 1%w/w sulphur) are used, this may preclude the need for FGD. SCOLF allows for derogation from this limit where the Emission Limit Values set out in LCPD are met.

Gaseous Fuels

These include natural gas and other sources, e.g. mine gas; vaporised LPG, refinery gas and gases from the production of smokeless fuel; together with that from the gasification of coal, oil or other carbonaceous matter in a separate plant, or the underground gasification of coal.

If a plant designed for and normally operated on gaseous fuel not requiring the use of flue gas treatment plant, has to resort to the use of standby fuel because of an interruption in the gas supply, then for short periods only, such plant may be allowed to operate without flue gas treatment which would normally be required. The applicant should propose operational scenarios to the Regulator. The Regulator and the local authority in whose area the plant is situated should be informed of such usage of standby fuel and when the return to gas firing is made.

Biofuels

Biofuels are renewable fuels derived from plant and animal materials. Plant material may be specifically grown crops (e.g. willow and oil seed), or waste products (e.g. pine kernels), which can be burnt to produce energy. Biomass material may include trees and straw, forestry wastes and agricultural waste (for example chicken litter)

The use of biofuels can be an attractive option for Operators, particularly in helping to meet obligations through climate change agreements and/or greenhouse gas emissions trading as biofuels are considered to be carbon neutral. This is because the carbon dioxide released into the atmosphere during combustion of the biofuel is no more than that removed through photosynthesis during the plant's lifetime.

The emissions from burning biofuels will depend upon the biofuel used, and from where it is derived. For example, biomass grown in coastal areas tends to have a much higher chloride content than that grown further inland. Similarly the composition of the soil in which the plants were grown can influence the composition of the biomass for example through the uptake on some heavy metals into the plant.

Certain biomass wastes may exempt from the requirements of WID. For further information refer to IPPC Co-Incineration Supplement. http://www.environment-agency.gov.uk/commondata/acrobat/coincinerator_924475_924475.pdf

Waste derived fuels

These are fuels derived from wastes that are not biomass derived or do not fall within the definition of biomass as described in Article 2 (11) of the LCPD. Waste derived fuels can include pelletised refuse derived fuel (RDF), solvents, tyres or other waste materials with a useful calorific value. These fuels may also include hazardous wastes. The combustion of these fuels to produce energy is termed "co-incineration" and are subject to specific requirements of the Waste Incineration Directive.

Note that fuels derived from waste materials remain classified as waste until the point of combustion.

Mixed Fuels

Multi-fuel firing

For a new plant with a multi-fuel firing unit involving the simultaneous use of two or more fuels, the LCPD sets the method by which emissions limit values should be calculated.

1.7.3.2 Other Plant

Cooling equipment

Power generation processes involving large boilers and furnaces produce significant quantities of low grade heat. Power generation plants employing water-cooled condensers use large volumes of water in the cooling systems to remove this heat. This water is typically treated with chemicals and, although concentrations will be low, it forms a very large volume aqueous stream from many such sites.

Dust and ash handling

Coal fired plant produces considerable quantities of ash. This has to be transported around site, stored and sent for final disposal or use. There is the potential for dust emissions to air and where ash lagoons are used, a waste water (run-off) stream may be produced.

The major release points from the processes to the environment are identified. Individual sites may vary considerably, depending in particular on the scale of operation, type of combustion plant, fuel(s) used and abatement techniques used.

1.7.4 Turbine Engines

1.7.4.1 Process Overview

The industrial turbine engine is an internal combustion engine which produces power by the controlled burning of fuel. A compressor draws in clean filtered ambient air and compresses it. Fuel is mixed into a proportion of this air in a combustion chamber and ignited. The heat produced creates a rapid expansion of the gas. Controlled addition of further compressed air forms the flame and controls the temperature at a level compatible with the materials of construction of the turbine. The expanding gases are fed through a turbine which drives the air compressor and the remaining power is used to drive a load such as an alternator, compressor or pump. Although most of the energy is removed from the gas flow by the turbine stages, the exhaust gases leaving the turbine are very hot, typically about 500°C. In a combined cycle plant some of this energy is recovered in a waste heat boiler, the steam raised being directed to an additional steam turbine and alternator, increasing the overall efficiency. Additional fuel may be fired in the gas turbine exhaust (supplementary firing).

The use of gaseous or liquid fuels in combined cycle gas turbine installations is significantly more energy efficient than conventional fossil fuel fired steam raising electrical generation facilities. Modern combined cycle plants are expected to be about 55% efficient whereas

existing conventional plants have an efficiency of about 35% - 40%. Gas turbines are often utilised in CHP installations, supported with supplementary firing.

There are two basic types of industrial turbine engine - the lightweight, aero-derived unit and the heavyweight units derived from steam turbine technology.

There is a wide range of power available from turbine engines, ranging from approximately 0.4MW to over 330MW electrical power output. It is convenient to split the range into three categories:

Small Turbines	<20MWe
Medium Sized Turbines	20-50MWe
Large/Heavy Duty Turbines	>50MWe

In addition to the size, the underlying technology is also a useful way to distinguish between turbine engines:

Aero-derivative unit

Aeroderivative turbines are based on jet engines and have been adapted for stationary use with a maximum size of around 50MWe. They tend to be relatively light, thermally efficient and often operate under high pressure. The aero-derived type of gas turbine is more adaptable to variable loads than the heavyweight and is therefore used for electrical peaking applications. It is also widely used for gas and oil pumping, electrical power generation and CHP applications. The turbine may contain more than one concentric shaft to obtain optimum performance from different stages of gas expansion and air compression.

Industrial unit

Gas turbines designed specifically for stationary use are referred to as 'Industrial' turbines. They are generally heavier and more rugged than the aeroderivative machines and usually operate at a lower pressure and can operate for longer between overhauls.

The heavyweight gas turbines are used mainly for electrical generation and CHP plants. They are often built as a single shaft machine encompassing the compressor, turbine and power turbine are on a single shaft.

On start-up the complete rotor has to be accelerated to a self-sustaining speed, usually by a diesel engine or electric motor. For power generation they can maintain good speed control in the event of loss of electrical load.

1.7.4.2 Fuels

Gaseous fuels are predominantly used, including natural gas, hydrogen, refinery gas and gasification process gas. Distillate fuel oils are also used. The technical difficulties of removing particulate matter from the gas to minimise turbine damage usually preclude the direct use of cheaper, less clean fuels such as coal and residual oils.

The main fuel used, and proposed to be used for electrical generation in the UK, is natural gas which is also used to fuel the gas pumping station turbines. Distillate fuels are normally used on installations for standby electrical generation capacity and sometimes as a standby fuel to gas for base load applications.

1.7.4.3 Recent developments

Improvements have continued in gas turbine efficiency, with the largest aero derivative turbines >50 MWth, reaching about 42% open cycle efficiency and single shaft machines about 40%. In addition to the internal design of the turbine, intercooling between stages of air compression has been applied to enhance performance in a few instances. The latest turbine developments are reported to achieve a CCGT overall efficiency approaching 60%.

1.7.5 Reciprocating Engines

1.7.5.1 Process Overview

Reciprocating Engines is a general term encompassing Spark Ignition (SI) and Compression Ignition (CI) devices.

Spark Ignition

SI engines are used for stationary power generation and are often used as the prime mover in small and medium scale CHP applications < 20 MWe. They are generally fuelled by methane (natural gas) and sometimes by gas produced by pyrolysis or gasification. They are commonly used in applications to recover landfill gas.
http://www.environment-agency.gov.uk/commondata/acrobat/lftgn06_treatment_936556.pdf

Gas engines tend to operate at speeds of 1500 or 1000 rpm and most modern machines are fitted with turbo-chargers and intercoolers.

Gas engines used in industrial CHP applications tend to be in the range 1 – 5 MWe with shaft efficiencies of around 40% (of gross NCV, measured at the alternator). At these sizes, gas engines have higher shaft efficiencies and lower capital costs (£/KWe) than comparable gas turbines.

Compression Ignition

Modern machines are fitted with turbochargers and air coolers, which produce an increase in the power output of the machine of up to 250% and at the same time achieve a substantial reduction in the Specific Fuel Consumption (SFC).

As CI engines have grown in size there have been improvements in reliability, endurance, capital costs, power to weight ratio, power to volume ratio and a gradual reduction in SFC.

This Note covers only the large engines likely to be used in an installation aggregating to 50MW net thermal input or more. These engines typically operate at about 600 RPM and have cylinder bores of about 400mm in combinations of 6, 8, 9, 12, 16 or 18 cylinders. They have a typical output power range of 5-15 MWe individually.

Smaller engines operate at higher speeds and tend to have lower oxides of nitrogen emissions but higher levels of carbon monoxide and hydrocarbons in the exhaust gases.

4-stroke CI engines

Most large CI engines installed in the UK have been of the 4-stroke type. The fuel consumption versus output curve is fairly flat and, typically, SFC increases by about 10% at half load. The thermal performance below half load deteriorates whilst the pollutant emissions in the exhaust gases increase.

The 4-stroke machines run hotter and at higher pressures than 2-stroke and as a consequence the exhaust gases carry more recoverable heat.

2-stroke CI engines

There are some very large dependable 2-stroke machines with a good SFC but they tend to be costly. The power from the 2-stroke engine is obtained by employing a longer piston stroke and a larger cylinder volume. The result is a lower number of cylinders but larger and heavier machines. The exhaust pollutant emissions of 2 and 4-stroke machines are similar.

Industrial applications

CI engines operated only for shaft power to generate electricity approach a thermal efficiency of 40%. High pressure engines are available with efficiencies up to 45%. CI engines are used where there is a cheap source of fuel in remote locations or where the waste heat in the exhaust gases can be utilised.

There are also some large CI engine installations safeguarding electrical supplies in the event of a general supply failure.

1.7.5.2 Fuels

Gaseous Fuels

Natural Gas

Natural gas has become a primary fuel source for CHP units. The main component of natural gas is methane augmented with a mixture of higher order hydrocarbons. The use of natural gas to displace oil has reduced the environmental impact of CHP. The very low sulphur content of the fuel results in very low sulphur dioxide emissions. Using lean burn technology NO_x emissions are reduced with carbon emissions of about 50gC/kWh of delivered energy.¹

Gas engines are designed to run either stoichiometric or lean-burn combustion regimes. In the lean burn case, NO_x and hydrocarbon emissions are reduced by running with high levels of excess air. Lean burn engines operate very close to the lean flammability limit and variation in composition can result in high NO_x emissions or engine misfire. Stoichiometric engines have the ability to use three-way catalytic converters to reduce CO, HC and NO_x. In both cases close control of air fuel ratio is required.

There is no universal natural gas quality standard. The composition of natural gas varies throughout the world. Slight variations also occur locally as supply changes and seasonal adjustments are made by the local gas distributor. In the UK, the gas quality is specified under the Gas Safety (Management) Regulations. The natural gas specifications are set primarily to meet the needs of the pipeline and domestic and industrial consumers and do not consider the needs of SI gas engines. Most international specifications require oxygen concentrations less than 1% by volume to minimise pipeline corrosion, in the UK this is maintained at less than 0.2% (molar). Water content is also controlled to ensure that the gas is above dewpoint to prevent pipeline damage. Inert compounds such as carbon dioxide and nitrogen are added to maintain a steady heating value and Wobbe Index. The Wobbe Index of natural gas varies between about 46 MJ/m³ and 52 MJ/m³ and in the UK is regulated to be within 47.2 MJ/m³ and 51.41 MJ/m³. To meet seasonal loads, butane and propane are added, which considerably alter the operating characteristics of gas engines.

Changes in gas composition are usually accommodated in gas engines by closed loop adaptive control systems. The effect of gas composition on engine behaviour can be characterized by the Methane Number (MN) and Wobbe Index. The Methane Number or Motor Octane Number (MON) can be used to predict the knock resistance of a fuel, but some manufacturers have their own predictive methods, which give better account of the chemical kinetics and propensity for auto-ignition and knock.

The fuel composition can also affect emission of unburnt hydrocarbons. Methane emission is particularly important due to its high environmental impact and poor methane oxidation capability of current catalysts. The exhaust sulphur emissions originate from the hydrogen sulphide, mercaptans, odorant and lubricating oil sulphur content. In the UK sulphur content is less than 50 mg/m³ (including a maximum hydrogen sulphide content 5 mg/m³). Even this relatively low sulphur emission is sufficient to poison any catalyst and degradation of conversion efficiency occurs. Sulphur poisoning affects the conversion efficiency of methane to a greater extent than the non-methane hydrocarbon (NMHC) content.

Distillate oils

The longest established fuel for CI engines is gas oil, which is a medium distillate product. These distillate fuels are now regarded as costly because their manufacture is energy intensive, but they enable maximum thermal efficiency to be obtained from the engine. A typical net calorific value for gas oil is about 43 MJ/kg and it is usually regarded as a 'clean' fuel.

Excess air for combustion and scavenging for both 2 and 4-stroke machines results in an actual exhaust gas oxygen concentration between 12% and 14% v/v (dry basis). The limiting sulphur content of gas oil is currently 0.2% w/w (falling to 0.1% from 01.01.2008) and this produces up to approximately 87 mg/m³ of sulphur dioxide in the exhaust gases. Only small quantities of sulphur trioxide are produced.

Distillate oil-fired CI engines produce up to 2500 mg/m³ of oxides of nitrogen (calculated as nitrogen dioxide) in the exhaust gases. Some hydrocarbons leave the engine unburnt and, during combustion, decomposition products are also formed. Typical hydrocarbon emission figures are up to 100 mg/m³.

Carbon monoxide formation is a function of combustion temperature, mixing and the combustion air to fuel ratio. Emission figures up to 100 mg/m³ are obtained. Total particulate matter consisting of soot (mainly unburnt carbon) and small quantities of ash from the fuel usually produce an emission figure up to 50 mg/m³. The above levels are typical of modern engines adjusted for maximum thermal efficiency. With poor combustion conditions there may be gas oil odours at ground level as well as higher levels of emissions.

Residual oils

A wide range of residual oils are used as fuels for CI engines. These engines require a number of special features and have a comparatively reduced power output against gas oil fuelled engines. SFC is only slightly affected. The fuel specification indicates high levels of sulphur, ash, asphaltenes, vanadium compounds, sodium compounds and usually both aluminium and silicon oxides. It is common practice to put such fuels through a high speed centrifuge before injection to remove water, sediment and also abrasive ash, which might cause cylinder wear.

The oxides of nitrogen emissions from residual oil firing are similar to those from gas oil, but the sulphur dioxide and particulate matter emissions from the engine will be higher.

The presence of vanadium compounds in the oil promotes the formation of sulphur trioxide. Particulate matter emissions are mainly unburnt carbon and traces of various metal compounds from the oil. Particulate matter emissions up to 100 mg/m³ are obtained from the engine and these particles tend to be very fine, with more than 50% below 1 micron in size. The higher sulphur content of the fuel requires that a basic lubricating oil is used and this may also result in small quantities of very fine calcium-containing particles being emitted from the engine.

Dual fuel

Dual fuel engines are started and usually put on load on liquid fuel. When stable operating conditions are reached they are changed over to gas operation with pilot liquid fuel (usually fuel oil) injection corresponding to 5 to 7% of the total heat input.

Some 4-stroke engines have the facility for either dual fuel or oil firing. The oil used may be either gas oil or heavy fuel oil. For dual fuel engines the pilot fuel may be gas oil or heavy fuel oil. Emissions from engines using dual fuel firing differ from those using oil fuels. The principal differences are a reduction in oxides of nitrogen to about 600 mg/m³ and in particulate matter to about 20 mg/m³. Carbon monoxide is increased and levels up to 450 mg/m³ can be expected. Unburnt hydrocarbons also increase and will include methane in the exhaust gas.

The presence of vanadium compounds in the oil promotes the formation of sulphur trioxide.

Particulate matter emissions are mainly unburnt carbon and traces of various metal compounds from the oil. Particulate matter emissions up to 100 mg/m³ are obtained from the engine and these particles tend to be very fine, with more than 50% below 1 micron in size. The higher sulphur content of the fuel requires that a basic lubricating oil is used and this may also result in small quantities of very fine calcium-containing particles being emitted from the engine.

1.7.6 Carbonisation & Associated Processes

1.7.6.1 Low temperature carbonisation (LTC) of coal to produce smokeless fuel

In coal carbonisation, the relative terms low and high temperature reflect the degree of carbonisation needed to remove volatile matter from the coal, leaving the solid carbonaceous product desired. Smokeless fuels are produced by low and high temperature batch carbonisation processes, the former at about 640°C in retorts, the latter at about 1250°C in coke ovens.

The "Coalite" process is the only survivor of several original commercial LTC processes. It is now only in use at one plant in England, using a unique technology to produce smokeless fuel.

The majority of washed coals received by road or rail are transferred to bunker storage. Some are stored on open stockpiles.

Conveyor belts transfer coal from the plant's feed hopper, without further crushing, to enclosed storage bunkers. Blending is achieved by controlling the rate of extraction of coal to a conveyor leading to battery-top coal bunkers.

Retorts are charged with coal by operators using a travelling combined discharge/charge machine that positions itself on top of each retort. It is filled from the battery-top coal bunker without coal dust releases. Fume releases occur from the open retort top during charging when the lid is manually removed and until the charging machine has been sealed in position. Fume releases also occur from the open retort top after the charging machine has been moved and whilst the coal charge is levelled prior to lid replacement and sealing. Minor fume releases can occur from seals on discharger ram shafts. Releases can arise from each retort for several minutes during each charge/discharge operation.

Batch carbonisation of coal occurs for four hours at 640°C, without releases to air, in each vertical cast iron retort heated by undesulphurised coal gas. Intermittent "green" gas releases occur regularly over several minutes during manual cleaning of retort gas off-take pipes as part of routine maintenance.

Once carbonised, the product is discharged into a cooling box situated beneath the retort. Cooled solid product discharges from the cooling boxes on to enclosed drag-bar conveyors kept under suction. Small quantities of water are sprayed on to the still hot product to minimise the likelihood of explosive mixtures being formed. The fume collection system comprises a cyclone separator for oil droplets, fan and discharge stack. The product falls from the drag-bar conveyor on to an enclosed conveyor of special design. The PVC belt is sealed to its enclosure which is evacuated by fan, via the drag-bars, to the smoke abatement and collection system. The product is transferred to enclosed primary screens. Dust releases from the screens are collected in a hood and arrested in a wet washer.

Raw gas evolved from coal during carbonisation is drawn under suction from retorts and passed to a gas treatment plant. This comprises in sequence an electrostatic precipitator that removes coal-oil and condensers that produce an aqueous liquor and fresh oil. The treated gas then enters water-sealed gas holders to be used as battery heating fuel and in steam-raising boilers. Excess undesulphurised gas is flared.

Flue gases from battery heating are used to raise steam in waste heat boilers.

The products are:

- solid product - (undersize product (below 5 mm) is burnt under boilers, re-cycled after crushing in a controlled ratio into the coal charge to retorts, or sold),
- coal gas - (coal gas purification is currently limited to the removal of oil-fog by electrostatic precipitation and condensation before entering water-sealed gas holders. Odour releases are possible from contaminated water in holder seals),
- coal oils - (crude coal oil from the electrostatic de-tarrer and fresh oil decanted from the liquor separator are stored in closed tanks venting to atmosphere),

- aqueous liquor - (aqueous liquor contains a number of chemical species which are recovered before the liquor is treated prior to discharge).

1.7.6.2 Production of smokeless fuel briquettes

There are a variety of established processes for the heat treatment of coal with or without a liquid binder to produce briquetted smokeless fuel:

Processes using smokeless fuel (anthracite)

These processes use smokeless fuels based on anthracite. All the processes follow the production sequence of preparing coal, mixing coal with binder, conditioning the mixture, forming briquettes under mechanical press, curing (with a few exceptions) and quenching in water.

Coal preparation can involve drying, crushing and screening by dust-generating processes that need containment and arrestment. Mixing prepared coal with liquid binder is carried out in enclosed pug machines. Smokeless binders e.g. sulphite lye and molasses, can evolve odorous gases, whereas bitumen binders also produce smoke.

Briquettes require de-smoking by heat treatment in a curing oven. A typical oxidiser curing oven consists of a steel mesh conveyor which passes through an enclosed oven in which hot gases are circulated from a hot gas generator. Combustibles evolved are burnt completely in the oven or hot gas generator from which flue gases may be used to raise steam and dry the coal feed before being finally scrubbed, where necessary, and discharged to air.

Cured briquettes are quenched in water before passing to product stock. Loading briquettes from stock can create windborne dust.

1.7.6.3 Activated carbon manufacture

Activated carbon is produced in a variety of size ranges because of its diverse uses. It is the crushing/grinding and classification operations that often lead to environmental releases.

Partially carbonised coconut shells or coal briquettes are activated with steam at high temperature in a rotary kiln or vertical retort. After discharge and cooling, the product is crushed and graded to the required size range.

Alternatively a carbonaceous material (usually wood) is chemically activated using phosphoric acid solution followed by chemical reduction to carbon in a kiln.

Rotary kiln

Partially carbonised coconut shells are fed from a lorry into a storage hopper then, in batches, into the kiln by an automated feed system. They pass co-currently with process gases along the kiln. The product discharges into screw coolers, and is conveyed into product bins. The carbon is activated by the injection of steam into the kiln. A small proportion of the carbon reacts with steam at 900°C to form carbon monoxide and hydrogen. The kiln temperature is maintained by burning the carbon monoxide and hydrogen with supplementary air injected along the length of the kiln. The volatiles generated from the feed material during the process are also burned in the excess air. The kiln is maintained at a reduced pressure by an exhaust fan. Gases generated in the process pass through a gas-fired afterburner chamber, waste-heat boiler and cyclone scrubber before discharge to atmosphere. The fine solids separated out from the gas stream are collected in the cyclone seal tank, and are filtered out and collected as a sludge

Vertical retorts

The batteries of vertical retorts produce activated carbon using either lump carbonised coconut shell or coal briquettes: Each battery consists of 4 retorts each of which is surrounded by regenerator bricks. At any one time only one side of the regenerator bricks is being used to store heat. The other side (termed the steaming side) is used to superheat

the steam which is used to activate the carbon. At regular intervals the retorts switch over and the steaming side becomes the regenerator side and vice versa.

The feed material is manually fed into the retorts through charging pots and slowly descends down the retorts until it reaches the activation zone where it reacts with superheated steam. The activated carbon product is discharged through a rocker box and water-cooled screw conveyor into semi-bulk containers.

Air is blown into the regenerator side of the retort to support combustion of the retort gases. Some of the product gases are vented to atmosphere, the remainder are re-cycled into the steaming side of the retort.

The volatile material in the feed is given off as the material passes down the retort and is extracted through a caustic scrubber by an exhaust fan. The light volatiles are blown by the exhaust fan back into the retort gas recirculation system and the heavy volatiles condense and overflow into the tar settling tanks where they separate into 3 fractions. The heavy tar and the light oil phase are periodically removed by road tankers. The aqueous phase is re-cycled back into the scrubbers on the batteries.

Grading plant

The grading plant breaks down the raw activated carbon through sets of rollers and the product is fed directly to a series of screens which split the granular material into the required size ranges. The dust generated on the plant is collected

1.7.6.4 Carbon black manufacture

There are currently two manufacturers within the UK. All processes involve the thermal decomposition of a vapour phase hydrocarbon to produce a carbon aerosol, however there are two methods of achieving this, termed the furnace process and the thermal process. The particles are separated, densified and pelletised.

Carbon black manufacture

Introduction

Although differing in detail, all carbon black processes involve the pyrolysis of a vapour-phase hydrocarbon to produce a high purity carbon aerosol from which the particles are separated and further processed to final products. Flue-gas composition depends on the feedstock and reactor conditions, whereas the organic impurities adsorbed on the carbon black are determined primarily by reactor conditions, especially thermal history. Depending on the process the newly formed carbon black is exposed to temperatures of 1000 to 1900°C for residence times of a few milliseconds up to 10 seconds.

Furnace process

This is a continuous process, widely adopted throughout the world. The pre-heated feedstock is atomised in specially designed furnaces fed with pre-heated air from a bank of blowers. Combustion of part of the feedstock generates temperatures of around 1900°C and the intense heat cracks the remainder of the feedstock to carbon black and various gases. Strict control of air rates, turbulence and residence time together with the furnace design, determine the quality and grade of carbon black produced. Natural gas is used in the reactors to control quality.

After the cracking reaction has been quenched with fine sprays of water, the carbon black is removed from the gases by fabric filters. The cleaned gases, although of very low calorific values, are burned to provide heat for drying the wet pellets, to raise steam for the process and electricity generation or flared. The carbon black is densified and pelleted either by a wet or a dry process (see pelletising below).

Pelletising

Pelletising can be either a wet or a dry process.

In dry pelletising, the product, after grinding and conditioning, is conveyed from the storage tank and fed by means of screw feeds to a rotating drum. The pelletising process requires "seeding" by re-cycling of product to the front end of the dryer.

In wet pelletising, the stored product from the agitator tank is fed to the pelletiser inlet where water sprays damp the product to assist in pelletisation. The pelletiser has an internal cylinder heated with circulating hot water to prevent caking. The wet product from the unit is then dried. The dryer, which is constructed in corrosion resistant material, uses indirect heat between the outer and inner casings.

Cooler air passing through the dryer centre in contact with the product is passed through a purge filter system. The product collected on these filters is re-cycled to the process.

After pelletising, by either method, the product is discharged and transferred by screw and elevator to the finished-product storage hoppers from where it flows to automatic bag-filling machines, into semi-bulk containers, or road tanks as required.

1.7.6.5 Other processes including specialist carbon products

A combination of tunnel and batch kilns is used to carbonise various carbon based raw materials to produce a range of electrical and other specialist carbon products.

Specialist carbon products

Raw materials such as carbon powder, coal tar pitch and tar oil are processed to produce a range of carbon products such as seal rings, bearings and counterfaces as well as carbon brushes and pantograph collectors which provide an electrically conducting pathway between stationary and moving parts in electrical machinery. The raw materials are prepared in various ways including premixing, grinding, milling and powder blending. Binders and other additives are blended depending on product specification. A sulphur flux is used in some processes which may lead to a high concentration of sulphur dioxide in the flue gases. The product of the blending and mixing operations may be extruded or pressed followed by carbonisation in batch or tunnel kilns. Releases from the kilns are oxidised in exhaust-gas incinerators before discharge to atmosphere via dedicated chimneys. Finishing operations

1.7.7 Gasification/Pyrolysis

Introduction

Gasification and pyrolysis are thermal processes that break down carbon bearing material, in an oxygen depleted atmosphere.

Gasification involves using a small amount of oxygen to produce a synthetic gas (syngas), together with a liquid oil. The pyrolysis process degrades waste to produce syngas, char and pyrolysis oil.

Overview

At larger scales of operation (>500MWth), direct combustion of some solid and liquid fuels may not represent BAT for conversion of a fuel to energy. In these cases, solid and liquid fuels may be partially or completely gasified, which involves the reaction of a source of carbon, (possibly with associated combined hydrogen), with a source of hydrogen and/or oxygen to yield a synthetic gas containing carbon monoxide, hydrogen, carbon dioxide and methane. The composition of the gas is dependent on the ratio of the reactants utilised and on the reaction conditions. Water vapour will also be present.

The carbonaceous feedstocks would normally be coal, lignite or gas/liquid hydrocarbons ranging from natural gas condensate or light distillates to residual oils or asphalt's. Other possible feedstocks include bitumen, petroleum coke, waste lubricants, waste plastics, refuse derived fuel, biomass and other carbonaceous wastes.

The principal processes available are:

- catalytic gasification with steam;
- thermal hydrogenation; and
- gasification with oxygen and/or steam, or with air and steam.

The feedstock is prepared and fed to the gasifier in either dry or slurried form. The feedstock reacts in the gasifier with steam and oxygen at high temperature and pressure to produce the syngas. Inorganic materials (such as ash and metals) are converted into a vitrified material resembling coarse sand. With some feedstocks, valuable metals are concentrated and recovered for reuse.

The resulting gas may then be desulphurised and particulates removed, leaving a "cleaner" fuel gas for combustion in a conventional gas-fired boiler or more efficiently by using combined cycle gas turbine technology. This latter process is known as Gasification Combined Cycle (GCC) and various degrees of integration are possible.

With the exception of two installations using Lurgi fixed-bed dry ash gasifiers and a number of small plants using by-product coke as a feedstock, gas production from coal was formerly conducted using variations of the old fashioned gas works and coke oven batteries. These processes were phased out in the late 1960s/early 1970s when cyclic and continuous plants using light distillates became available. The latter were progressively phased out following the introduction of natural gas. It is not expected that partial gasification in batteries would form any part of future plans for coal gasification. Any future coal gasification plants would probably utilise high throughput continuous complete gasification plants, partial gasification plants or in situ underground coal.

At the present time, there are many proven gasification plants around the world, mainly in the chemicals industry or making synthetic transport fuels; global syngas production is growing at around 10% per annum. Consequently, gasification is considered a commercially proven technology.

Commercial processes and those in advanced development

Any solid or gaseous/liquid feedstock containing carbon can be gasified. The use of oxygen rather than air will produce a gas with a higher heating value and a mix of mainly hydrogen and carbon monoxide, with some methane, depending on the process. The quantity of hydrogen could be increased by further processing through a shift converter.

Oil feedstocks available for large scale commercial gasification can range from natural gas liquids through to high sulphur heavy residual oils from refinery operations. The choice of process used depends on the product required and the composition of the feedstock. For example it may be required that the product is rich in hydrogen and/or carbon monoxide for use as a chemical feedstock (synthesis gas) or rich in methane to facilitate conversion to Substitute Natural Gas (SNG). Product gas rich in hydrogen would normally be required when used predominantly for hydrogenation reactions.

Processes are also available for the complete or partial gasification of coal. The latter processes are usually part of topping cycles and the residual solid (char) is usually sent forward for combustion in a fluidised bed combustor. One such process, the Air Blown Gasification Cycle (formerly known as the British Coal Topping Cycle), is included in this Note.

Processes which have been operated on a commercial basis include those listed below.

Catalytic gasification with steam

This process can be utilised with distillate oil fractions. Sulphur-free light distillates are reacted with steam over a nickel based catalyst to give a primary gasification product containing methane, carbon dioxide, carbon monoxide and hydrogen.

The proportion of gasification products is dependent on the reaction temperature; higher temperatures are necessary for heavier feedstocks. These result in a reduction of methane

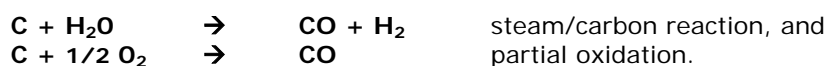
and carbon dioxide content and increases in the carbon monoxide and hydrogen concentrations. If the process is being used for SNG production further catalytic methanation stages can be used operating at lower temperatures when the equilibrium moves in favour of methane production. At temperatures of around 300°C a product containing methane and carbon dioxide in the ratio of approximately 3:1 results, with only traces of carbon monoxide and hydrogen remaining. After removal of carbon dioxide the gas is substantially pure methane.

Thermal hydrogenation

The removal of sulphur from heavy fuel oils is more difficult and costly than from distillates. Consequently heavy oils cannot be gasified catalytically with steam because the sulphur content leads to catalyst poisoning. They can however be reacted directly with hydrogen at high temperatures and pressures to make methane, ethane and by-product aromatics. The gas can then be readily desulphurised.

Gasification with oxygen (or air) and/or steam

These gasifiers generally operate at high temperatures. The solid or liquid hydrocarbon feedstocks are reduced to low molecular weight substances such as carbon monoxide and molecular hydrogen. The chemical reactions which take place in these gasifiers are numerous. Essentially in an oxygen and steam fed gasifier the reactions may be summarised as:



The composition of the synthetic gas which is produced by the gasifier will depend on the feedstock utilised, the steam to oxygen ratio and the temperature and pressure at which the gasifier is operated. Although oxygen is fed into the gasifier, a reducing atmosphere exists and as a result sulphur present in the feedstocks is converted to H₂S, with smaller amounts of carbonyl sulphide, methyl mercaptan and carbon disulphide being produced.

Fuel-bound nitrogen will be mainly converted to molecular nitrogen, but in the presence of hydrogen, some small quantities of ammonia and hydrogen cyanide will be produced. The ratio of ammonia to hydrogen cyanide is of the order of 100:1.

The nitrogen formed as a by-product of air separation to produce oxygen for the gasifier may be used to provide inert atmospheres in the milling and dust handling areas of coal fed gasifiers and where IGCC plants are operated, it can be fed to the gas turbine to assist in lowering NO_x formation and recover power.

Gasifiers can achieve between 70 and 93% cold gas efficiency (most operate at between 78 and 85%) and over 99% carbon conversion can be expected from many gasifier designs where coal or residual oils are the feedstocks. Much of the remaining energy in the feed can be extracted as usable heat. Inspectors should note that cold gas efficiency can be misleading if comparisons are being made between different gasifiers, different feedstocks (fuels), or between gasification and other (e.g. direct combustion) technologies.

Different designs of gasifiers operate at markedly different temperatures. Those operating at lower temperatures will release the mineral content of the feedstock as an ash, which can be separated from the fuel gas stream; whilst those operating at higher temperatures will produce a molten slag which can be quenched in water to produce a hard, generally non-leachable glassy slag.

Some of these processes can produce a significant carbon carryover in the form of soot which can be removed prior to the main product purification stages, e.g. by water wash after gas cooling.

Processes are available for the recovery of the soot from the water wash and this may be recycled to the gasifier with fresh feedstock. Sulphur in the feedstock is present in the crude gas as hydrogen sulphide or carbonyl sulphide and, dependent on the subsequent use of the gas, can be removed to varying extents down to very low ppm levels. The

regenerative absorption or chemical methods used for removal of acid gases results in a concentrated acid gas stream which can be treated to produce elemental sulphur.

The conditions reached in these gasifiers, ensure that in well managed systems no polycyclic organic or phenolic materials are present at detectable levels.

Gasifier designs may be divided into three sub-groups:

- entrained flow
- fixed bed
- fluidised bed.

Brief descriptions are given below:

Entrained flow gasifiers

This is the most widely used design type. The reaction takes place in an entrained fluid flow or total suspension. This gasifier can be fed pulverised (<0.1 mm) coal (dry or in a slurry) or liquid hydrocarbons. Where coal is the feedstock, oxygen and steam are fed into the gasifier and the maximum operating temperature in the gasifier will normally be 1500 to 1900°C with operating pressures of 25-60 bar. With oil feedstocks the operating range is 1300-1500°C and 25-80 bar.

Where coal is the feedstock the ash melts to form a slag. Where oil residues are fired, most metal compounds will leave the reactor in the gas stream and will be recovered in the gas scrubbing system.

Entrained flow gasifiers have been used successfully in the USA (e.g. Texaco Gasifier at Cool Water Project using coal, 1984; Dow Plaquemine commercial power using lignite, 1987). Also, a series of other GCC and IGCC projects are currently being pursued in Europe. Texaco Gasifiers are to be used in three refinery oil residue applications in Italy (Isab, Priolo 507MWe; Api, Falconara 220MWe; and Saras, Cagliari 508MWe). Shell gasifiers are also used in gasification projects at Pernis (Shell Refinery) in the Netherlands, where a hydrogen co-product is produced, whilst the Porvoo (Neste Oy) plant in Finland is currently at the planning stage. These systems contain fully proven components linked together by a level of integration which their respective designers believed to be the most appropriate arrangement for the feedstocks being converted. The Netherlands Power Company (Sep) subsidiary Demkolec is using a Shell Entrained Flow Coal Gasifier with a boiler at a 250 MWe IGCC demonstration plant at Buggenum in Limburg. At Puertollano, Spain a project using the Krupp Koppers Prenflo Gasifier started up in 1995. This entrained gasifier will be used to gasify mixtures of local high ash coals and high sulphur petroleum coke.

Texaco gasifier

This technology was acquired by General Electric in 2004. In this process, coal is ground and mixed with water to form a slurry. Alternatively refinery oil residues are fed to the gasifier. This is gasified by adding a sub-stoichiometric amount of oxygen via a specially designed burner. Due to the gasification conditions, the gas is rich in hydrogen and carbon monoxide, and sulphur is converted to hydrogen sulphide. Ash leaves the gasification reactor as a molten slag.

Shell gasifier

In this process, coal is ground and injected as a fine dry powder. In contrast to the Texaco process the entrained flow gasifier reactor is fed from the sides and there is a membrane reactor wall. The coal ash content is removed as a slag. A primary heat exchanger (boiler) is part of the Shell gasification system design. The Shell gasifier generally uses a lower oxygen feed rate than the Texaco gasifier and thus the gas produced has low carbon dioxide level. Shell also have gasifiers designed for oil feedstocks and these are fed from the top and are refractory lined.

Other gasifiers

An operational Dow gasifier at Plaquemine, USA consumes 2100 tons per day of coal/water slurry feed. The E-Gas technology, previously known as the Dow or DESTEC design, is owned by Conoco Phillips and is a two-stage entrained gasifier in which the raw feed is

introduced into a second chamber of the reactor to internally cool the products of the first stage. This unit now processes 100% petroleum coke.

The Noell Gasifier technology, commercialised at BASF Seal Sands, UK has also recently been acquired by BASF from Future Energy Limited and has been selected for the possible UK IGCC project at Drym in South Wales. This technology uses a novel design in which moving ash is used to cool the reactor wall, thereby avoiding the need for fixed refractory

Fixed bed gasifiers

In the fixed bed gasifier lump coal of specific size is charged into the top of the reactor through a lock hopper. Fine coal can only be used at levels of up to 40% of the total feed (depending on coal type), the balance will need to be briquetted. Steam and oxygen enter the gasifier near the bottom and flow upwards, counter to the coal flow. The operational pressure of this type of gasifier lies in the range 10-100 bar. The bed of coal is not fixed, hence a more correct name for this group of gasifiers is sometimes used - "moving bed gasifiers". The reaction temperature usually lies between 800-1000°C for dry ash plant and 1500-1800°C for the British Gas Lurgi slagger, and therefore the mineral content of the feedstock is released either as ash or as slag. The calorific value of the gas produced by this type of gasifier is higher due to the methane content of the gas produced.

Lurgi fixed bed dry ash gasifier

This is a well established process whereby coal or lignite is gasified by steam/oxygen injection resulting in near total gasification of the feedstock leaving a dry ash to be disposed of from the reactor bottom.

The basic design of fixed bed gasifiers is relatively old. The technology has been successfully used in the UK at Westfield in Scotland, and Coleshill in England. In South Africa the world's largest gasification plant is based on this technology; in North Dakota, U.S.A., about 3.68 million standard m³ per day of synthetic natural gas is produced using dry ash gasifiers. The Lurgi and its higher temperature counterpart, British Gas - Lurgi gasifiers are considered available technology. The British Gas-Lurgi design operates at about 1600°C and as a result produces a molten slag similar to the entrained flow gasifiers.

BG / Lurgi slagging gasifier

This was developed from the original Lurgi gasifiers by British Gas and Lurgi. Early work showed that the efficiency of the dry-ash Lurgi gasifier could be improved significantly by reducing the steam/oxygen ratio and raising reaction temperature so that ash is discharged as liquid slag. British Gas modified one of their Westfield dry-ash units by replacing the rotating grate at the base of the gasifier with a refractory hearth with provision for slag tapping into a quench chamber and slag lock system. Injection of the steam/oxygen supply is achieved via tuyeres in the reactor shell above hearth level.

Fluidised bed gasifiers

Coal, milled to a 1-5 mm size range, is introduced into an upward flow of steam and oxygen adjusted to a flow rate which fluidises the coal. The bed temperature is kept low enough to prevent ash fusion, slagging and clinkering which would disturb the flow patterns within the fluidised bed. Such processes can only achieve high carbon conversions with reactive fuels such as lignite (brown coal). Not all gasifiers of this type are oxygen blown. Some air blown gasifiers have been developed.

High Temperature Winkler

The High Temperature Winkler (HTW) process, applied in one plant in Germany, utilises 730 tonnes per day of brown coal.

This type of gasifier is supposed to be used for an IGCC project (RWE's 300MWe KoBra) in Germany. The syngas goes forward to conventional gas cleaning prior to use, whilst residual bottom and fly ash which still can contain some carbon are burnt in a fluidised bed combustor.

Lurgi Circulating Fluidised Bed (CFB) Gasifier

Coal or other carbonaceous feedstocks are ground to <35mm (e.g. wood) or <5mm (e.g. coal) and fed to a CFB gasifier, along with air or oxygen and steam as required. Operation is slightly above atmospheric pressure. This process is suitable for a wide range of fuels, including coals with ash contents of 50%+ and for low plant capacities.

*Air Blown Gasification Cycle (ABGC)
(formerly known as the British Coal Topping Cycle)*

The Clean Coal Power Generation Group are developing a fluidised bed partial gasifier capable of producing a fuel gas suitable, after removal of particulate matter, for direct use as a fuel for a gas turbine. The process utilises a pressurised gasifier with air fluidisation, fine coal and limestone sorbent being injected separately. It is designed to gasify up to 80% of the coal in the gasifier (i.e. gasification is incomplete) with the remaining char being passed to a fluidised bed combustor (FBC). Dependent on the application, the combustion products from the FBC can be recombined with the gasifier product or used to raise steam etc in separate plant. The process will have a high overall thermal efficiency (~47% with cold gas clean-up rising to over 50% when hot gas clean-up becomes available). The limestone fed to the gasifier partially removes sulphur, the remaining sulphur leaving the gasifier in the gas stream. Due to the added limestone there is a considerable amount of mineral ash available for utilisation or for disposal from the process. Virtually all the NO_x produced from the combustion of the low cv gas is fuel NO_x. Plant sizes for air gasification will be considerably larger than for oxygen gasification in order to accommodate the much larger gas flows. However, air-blown processes preclude the necessity of an air separation unit

PYROLYSIS

Recently there has been an increased interest in pyrolysis processes. Although these may produce either a gaseous or liquid product, they are distinguished from gasification processes by treating the feedstock largely in the absence of oxygen. Pyrolysis typically takes place in an externally heated reactor, most commonly a horizontal inclined rotating drum with a seal at both ends. Burning gas, oil or some of the product of the pyrolysis may provide the heating. Feedstock, for example wood, is reduced in size if necessary. This operation is potentially noisy and dusty and may need enclosure and extraction to a filter. The feedstock enters one end of the drum through a screw feeder or ram. The hot gas flows in an external jacket or internal tubes countercurrent to the feedstock. Depending on the feedstock and operating temperature, a hydrocarbon gas and a condensable liquid (which may include tar) are evolved together with a solid char. The gas is separated, cooled and may need filtration if it is to be burned. Further treatment to remove pollutants such as sulphur compounds and ammonia may be needed with some feedstocks to meet combustion emission standards. The liquid product may be separated from tar and refined to meet a sales specification. The gas may be burned in a gas turbine or engine and the liquid and solid fractions used to raise steam in, for example, a fluidised bed boiler as part of a combined cycle power plant or a combined heat and power system. Alternatively the products may be sold for separate use. There should be minimal emissions from the pyrolysis plant itself, the BAT requirements being similar to those for gasification. The only planned release to air should be surplus gas during start-up that should be burned under controlled conditions in an incinerator rather than flared. Any emergency releases from safety vents, etc. should be flared if necessary to ensure safety.

1.7.8 Integrated Systems

Combined Heat and Power (CHP)

Combined heat and power (CHP) utilises waste heat in the combustion exhaust to either generate steam or hot water in a waste heat boiler or is used directly, as in the drying of process materials or the operation of absorption chillers. CHP is potentially applicable to the different combustion options and should be considered when configuring a new power plant.

As a result of utilizing this waste heat, thermal efficiency increases, whilst emissions per unit of useful energy produced drop significantly. This is an important factor when considering BAT.

Boilers

Overall thermal efficiencies for some processes and their associated systems can reach 90%; thus reducing the carbon dioxide release rate by more than 55% compared to conventional power generation combustion systems with a thermal efficiency of 38%. New combustion plant, which is to be used as part of some form of CHP scheme should however achieve the release levels given in Section 3 of this Note.

Gas Turbines

Additional fuel can be fired in the turbine exhaust. Overall thermal efficiencies of up to about 85% are possible, giving low emissions per unit of useful energy produced.

Reciprocating Engines

Combined heat and power

SI engines have significant potential for use as prime movers in Combined Heat and Power(CHP) schemes. CI engines can also be used in this way, although, because of the higher heat recovery potential available from SI engines and their lower capital costs (£/KWe) they are much less common than SI engines in CHP applications.

A typical SI engine with a shaft efficiency of approximately 40% rejects heat in a number of ways and at differing temperatures;

Table 1.7.8 (i) – SI Engines – Heat Rejection Parameters

Source	%age of gas input	Approx. temperature (°C)
Engine Exhaust	30	420
Jacket Water	8	80 – 115 ¹
Intercooler/oil cooler	9	40 - 60

¹ Jacket water temperatures are normally maintained below 90°C

High overall efficiencies can be obtained from CHP schemes based on SI (or CI) engines, however the level of efficiency obtained is dependent upon the ability to usefully use the lower grades of heat.

The full potential recovery of high and low grade heat can be up to 90% in a modern CHP scheme, such as those with district heating and cooling (via absorption chiller) circuits. Thermal performance falls rapidly with reducing load. Where steam is generated in a CHP scheme, the thermal efficiency is reduced with increasing steam pressure. Some engines are capable of operating at higher temperatures but can suffer operational and maintenance problems.

The maximum heat to power ratio obtainable from an SI or CI engine is about 1:1. Exhaust gases contain free oxygen and, as such, supplementary firing can be used to alter the heat to power ratio. It should be noted however that such arrangements are not common and can be unstable due to the pulsing nature of the combustion process.

The essential requirement of CHP schemes based on SI or CI engines is the maximisation of the efficiency of the combustion process (in this case SFC) and also maximisation of the utilisation of the heat and power produced from the combustion system.

Integrated Gasification Combined Cycle (IGCC)

When gasification is fully integrated, i.e. gasification with gas cleaning, synthesis gas conversion and turbine power technologies, it is known as Integrated Gasification Combined Cycle (IGCC). Such processes are capable of very low emissions per unit of useful energy produced. Sulphur can be recovered without the creation of large quantities of waste and the ash is in the form of a fused slag from some processes. These techniques have clear environmental advantages and are developing rapidly; current experience is with plant up to about 600 MW(th).

IGCC uses a combined cycle format with a gas turbine driven by the combusted syngas, while the exhaust gases are heat exchanged with water/steam to generate superheated steam to drive a steam turbine. Using IGCC, more of the power comes from the gas turbine. Typically 60-70% of the power comes from the gas turbine with IGCC, compared with about 20% using PFBC.

Coal gasification takes place in the presence of a controlled 'shortage' of air/oxygen, thus maintaining reducing conditions. The process is carried out in an enclosed pressurised reactor, and the product is a mixture of CO + H₂ (called synthesis gas, syngas or fuel gas). The product gas is cleaned and then burned with either oxygen or air, generating combustion products at high temperature and pressure. The present mainly forms H₂S but there is also a little COS. The H₂S can be more readily removed than SO₂. Although no NO_x is formed during gasification, some is formed when the fuel gas or syngas is subsequently burned.

Three gasifier formats are possible, with fixed beds (not normally used for power generation), fluidised beds and entrained flow. Fixed bed units use only lump coal, fluidised bed units a feed of 3-6 mm size, and entrained flow gasifiers use a pulverised feed, similar to that used in PCC.

1.7.9 Plaster Manufacturers

The inclusion of Plaster Processes in this sector arises because of the aggregation rule, where two or more appliances with an aggregated rated thermal input of 50MW or more are operated on the same site by the same operator, those appliances are treated as a single appliance with a rated thermal input of 50MW or more.

It should be noted that this part of the combustion sector differs from the majority as it uses combustion techniques to modify mineral properties within its processes and, and does not generate power or steam.

1.8 ECONOMICS

The electricity industry is one of the largest in the UK, contributing 1.2% of gross domestic product in 2001 (DTI UK Energy Sector Indicators 2003). The industry has gone through significant structural and regulatory changes over the past decade and many of these changes have impacted on the economic structure of the industry.

Immediately after privatisation the industry in 1989 there were 7 major electricity-generating companies in England and Wales, but by the end of 2002 this had increased to 32 major power companies. This is as a result of new operators entering the market and the two major non-nuclear generators (PowerGen and National Power) divesting generating plant. Some older generating plants have also been closed during the period as new generating capacity comes on line.

There has been a significant change in the competitive structure of the sector, brought about by the following step changes:-

- 1989 the electricity industry was privatised.
- From April 1990, customers with peak loads of more than 1MW (approximately 45% of the non-domestic market) were able to choose their supplier.
- From April 1994, customers with peak loads of more than 100kW were able to choose their supplier.
- By May 1999, the remaining part of the electricity market (below 100kW peak load) was opened to competition.
- March 2001, the means of trading electricity changed with the introduction in England and Wales of the New Electricity Trading Arrangements (NETA). These arrangements are based on bi-lateral trading between generators, suppliers, traders and customers. They introduce common and transparent rules for access to and charging for the transmission network and are designed to be more efficient and provide greater choice in the market place, whilst still maintaining a secure and reliable electricity system.
- April 2005. NETA does not apply in Scotland and NI, however new trading arrangements (BETTA) will apply in England, Wales and Scotland from April 2005. These electricity trading arrangements do not apply in Northern Ireland where the small number of generators tend to have longer term supply contracts."

For industrial consumers, the last 14 years have seen electricity prices fall, chiefly due to the fall in fossil fuel prices, but also because of efficiencies that were realised with the market opening up to competition. Prices remained broadly constant over the three years leading up to privatisation, before falling sharply in early 1990. Since 1993, and even more since the expansion of competition in 1994, prices fell consistently until mid 1996, when the rate of decline quickened as the Fossil Fuel Levy was steadily cut from 10% to 2%. This reduction means that the average annual industrial electricity real price in 1999 has fallen by 25.5% since 1990. In real terms prices are now lower than for any year since records began in 1970. (The Energy Report 2000, DTI).

The economic situation of an individual generating station is highly dependant on the type of fuel used. There has been a significant shift away from coal since the 1980's, balanced to a great extent by an increase in the use of gas. In 2002, electricity produced from the various sources in the UK was as shown in Table 7 :-

Table 7: UK Electricity production

Electricity production in 2002	
	GWh
Nuclear	88,043
Hydro	4,786
Wind	1,256
Coal	124,401
Oil	4,821
Gas	152,149
Other renewables	5,306
Other	3,728
Total production	384,490

Abatement Costs

Cost information for the key abatement techniques for reducing emissions of SO₂, NO_x and particulates is presented in this section. It has been possible to assemble a sizeable body of cost data by drawing on information from a number of sources such as published data, information from equipment suppliers and information from power generators. From a review of the data, mid-range estimates have been made for capital and operating costs for each type of abatement technique. It is considered appropriate to present the costs as follows:

- Capital costs in terms of £/kWe installed capacity of the combustion process. The capital cost data used in deriving suitable estimates represent, as far as possible, total installed costs for retrofitting abatement equipment. For new installations, economies would be expected at the design and installation stages, hence the quoted costs would generally be overestimates.
- Operating costs in terms of £/kWh of electricity produced, which will depend to some extent on the specific load factor of the combustion process. Operating costs are, as far as possible, inclusive of all recurring cost elements such as consumables, power, waste disposal, maintenance and labour. Also, as far as possible, the operating costs are inclusive of any revenues from the sale of by-products. Clearly each application has unique features and hence the following cost estimates should be regarded as indicative only, with an estimated accuracy of ± 50%.

The indicative costs of a range of wet and dry SO₂ abatement techniques are shown in Table 8.

TABLE 8: Indicative costs of SO₂ emissions abatement techniques

Technique	Typically achievable emission reduction	Process capacity (MWe)	Indicative capital cost (£/kWe, 1999 prices)	Indicative operating cost (£/kWh, 1999 prices)
Wet limestone scrubbing	90%	500	110	0.0010
		300	140	0.0010
		100	160	0.0010
Sea water scrubbing	90%	300–500	110	0.0011
Spray dry scrubbing	90%	500	70	0.0015
		300	120	0.0015
		100	170	0.0015
Dry scrubbing	90%	Various	70	0.0020
Sorbent injection (hybrid)	80%	Various	40	0.0040
Sorbent injection (duct)	70%	500	40	0.0040
		300	70	0.0040
		100	90	0.0040
Sorbent injection (furnace)	50%	500	30	0.0040
		300	50	0.0040
		100	60	0.0040

Source: Environment Agency Sector Guidance Note S3.1.01

The indicative costs of NO_x abatement techniques and combustion modifications are shown in Table 9

Table 9: Indicative costs of NO_x emissions abatement techniques

Technique	Typically achievable emission reduction	Process capacity (MWe)	Indicative capital cost (£/kWe, 1999 prices)	Indicative operating cost (£/kWh, 1999 prices)
SCR	85%	500	60	0.0015
		300	80	0.0016
		100	90	0.0018
		<20	125	0.0022
SNCR	50%	Various	10	0.0008
Reburn (Note 1)	50%	Various	30	0.0011
Over fire air	35%	Various	20	0.0001 (Note 2)
Flue gas recirculation	15 to 45%	Various	10	0.0001 (Note 2)
Low NO _x burner	30 to 50%	Various	10	0

Notes

Note 1. Incorporates over fire air.

Note 2. A nominal cost has been included to allow for additional power consumption, maintenance, etc.

Note 3 The techniques listed above are not applicable across all technologies, eg SNCR is not applicable to lean burn SI engines due to relatively low exhaust temperatures.

The indicative costs of particulate abatement techniques are shown in Table 10

Table 10: Indicative costs of particulate emissions abatement techniques

Technique	Typically achievable emission reduction	Process capacity (MWe)	Indicative capital cost (£/kWe, 1999 prices)	Indicative operating cost (£/kWh, 1999 prices)
ESP	Reduction to below 25 mg/m ³	Various	25	0.0003
Fabric filters	Reduction to below 25 mg/m ³	Various	10	0.0011

For applications that do not require reheating, the operating costs are mainly related to the costs of the reagent. Overall costs (investment and operating) for NO_x reduction in a 800MW power plant using SCR range between €1500 and €2500 per tonne of NO_x reduced [BREF 2003].

2 Techniques for pollution control

To assist Operators and the Regulator's officers in respectively making and determining applications for PPC Permits, this section summarises the indicative BAT requirements (i.e. what is considered to represent BAT for a reasonably efficiently operating installation in the sector). The indicative BAT requirements may not always be absolutely relevant or applicable to an individual installation, when taking into account site-specific factors, but will always provide a benchmark against which individual Applications can be assessed.

Summarised indicative BAT requirements are shown in the "BAT boxes", the heading of each BAT box indicating which BAT issues are being addressed. In addition, the sections immediately prior to the BAT boxes cover the background and detail on which those summary requirements have been based. Together these reflect the requirements for information laid out in the Regulations, **so issues raised in the BAT box or in the introductory section ahead of the BAT box both need to be addressed in any assessment of BAT.**

Although referred to as indicative BAT requirements, they also cover the other requirements of the PPC Regulations and those of other Regulations such as the Waste Management Licensing Regulations (see Appendix 2 for equivalent legislation in Scotland and Northern Ireland) and the Groundwater Regulations, insofar as they are relevant to PPC permitting.

For further information on the status of indicative BAT requirements, see [Section 1.1](#) of this guidance or [Guidance for Applicants](#).

It is intended that all of the requirements identified in the BAT sections, both the explicit ones in the BAT boxes and the less explicit ones in the descriptive sections, should be considered and addressed by the Operator in the Application. Where particular indicative standards are not relevant to the installation in question, a brief explanation should be given and alternative proposals provided. Where the required information is not available, the reason should be discussed with the Regulator before the Application is finalised. Where information is missing from the Application, the Regulator may, by formal notice, require its provision before the Application is determined.

When making an Application, the Operator should address the indicative BAT requirements in this Guidance Note, but also use the Note to provide evidence that the following basic principles of PPC have been addressed:

- The possibility of preventing the release of harmful substances by changing materials or processes (see [Section 2.1](#)), preventing releases of water altogether (see [Section 2.2.6](#)), and preventing waste emissions by reuse or recovery, have all been considered, and
- Where prevention is not practicable, that emissions that may cause harm have been reduced and no significant pollution will result.

This approach should assist Applicants to meet the requirements of the Regulations to describe in the Applications techniques and measures to prevent and reduce waste arisings and emissions of substances and heat - including during periods of start-up or shut-down, momentary stoppage, leakage or malfunction.

Operators of all large coal-fired power plants in England and Wales should have an agreed programme for producing a Management Plan to ensure that the permitted process meets the National Air Quality Strategy objectives by 2005 for sulphur dioxide, oxides of nitrogen and particulates (PM10) having taken account of general background, concentrations in the atmosphere, including those arising from other power stations.

General approach in England and Wales

Under IPC, large coal and oil-fired power stations in England and Wales supplying the national electricity grid have a number of additional controls, reflecting the scale and nature of their operation:

1. Site-specific controls: a Station A Limit on annual emissions of SO₂; a Site Annual Release Limit for NO_x; an Air Quality Management Plan and a Condition requiring them not to cause a breach of Air Quality objectives.
2. An Operator B Limit on total annual emissions of SO₂ from their portfolio of stations.

This framework will be developed to continue under PPC, taking account of requirements of the LCPD

2.1 IN-PROCESS CONTROLS

2.1.1 Material storage and handling

Solid Material

Coal, limestone and other solid raw materials may create a dust problem during receipt and subsequent handling and processing operations. Adequate measures should be taken to minimise particulate matter emissions to air.

Where practicable road, rail, barges or ships should discharge into purpose built enclosed hoppers with transfer to stockpiles or storage hoppers by enclosed conveyors. Similarly, where open stockpiles are justified, transfer to these from conveyor systems should be via enclosed discharge towers to minimise free fall of material and reduce wind whipping of fines. Coal may also be delivered by pipeline to site and stored for short periods as a suspension in water.

Removal of raw materials from stockpiles should favour conveyor systems to minimise the use of mobile plant. Where recovery of raw materials necessarily involves the use of mobile plant the discharge of the vehicles to process feed hoppers should be enclosed to minimise emissions of fine dust to atmosphere.

All transfers of potentially dusty materials within the process should utilise enclosed systems with extraction and arrestment equipment as necessary to prevent leakage of dust.

All screening, crushing, milling, briquetting and other plant for the pre-treatment and storage of raw materials prior to use in the process should be totally enclosed with extraction and arrestment plant, as appropriate, to prevent emissions to atmosphere. The dust handling plant should be fitted with ceramic or bag filters. Inspectors should note that for some gasification processes coal is milled to a very fine dust and requires handling with an inert gas blanket. Nitrogen may be available from an on-site Air Separation Unit.

Coal should be stored in walled bunkers, in heaps on drained hard-standing and in covered heaps on smaller sites. At larger sites coal should be kept in large heaps in the open, with drainage generally being to open ditches. Run-off of rain water from all open areas, but in particular from, stock pile areas, will contain suspended solids. It should be intercepted and the suspended solids removed by settlement or other techniques.

Supplies are delivered to site by road or rail transport, by ship or barge, or direct (by conveyor) from the mine. The principal releases to the environment from coal heaps will be dust (particulates) to air and leachate to water. Coal fired plant may use oil and gas as start-up and support fuels.

Coal charging for gasifiers should be via a double lock system, whereby the gases released from the reactor during charging are contained within the lock hopper. After closure of the charge valve they are routed either to recompression for re-injection into the crude gas

stream or to a vent treatment system. Alternatively, a wet feed (slurry) system may be used with comparable features.

Oil

Liquid feedstocks should be stored in roofed tanks. Venting arrangements will be dependent on the nature of the feedstock, its vapour pressure and composition. The size and number of tanks will depend on whether the oil is the main or standby fuel. Alternatively at larger sites oil may be supplied from nearby refinery sites by pipeline. Oil and oil emulsion storage facilities require heating plant to reduce the viscosity of the fuels.

Releases to the environment will include volatile organic compounds (VOC's) to air and may include spillage of oils from storage and transfer operations and the sludges which collect in tanks.

Gas

Gaseous fuels are not normally stored on site and are supplied by pipeline. Where gas is used as a fuel, local compression facilities may be required in order to inject sufficient fuel. Releases of gaseous fuels can arise from controlled venting during maintenance and purging of the fuel system.

Indicative BAT requirements for material storage and handling
<p>1 In general terms, BAT for the prevention of dust releases during handling of bulk raw materials is the appropriate combination of:</p> <ul style="list-style-type: none">• orientation of long stockpiles in the direction of the prevailing wind• installing wind barriers or using natural terrain to provide shelter• controlling the moisture content of the material delivered• careful attention to procedures to avoid unnecessary handling of materials and long unenclosed drops• adequate containment on conveyors and in hoppers, etc• the use of dust suppression water sprays, with additives such as latex, where appropriate;• rigorous maintenance standards for equipment• high standards of housekeeping, in particular the cleaning and damping of roads• use of mobile and stationary vacuum cleaning equipment• dust suppression or dust extraction and bag filter cleaning plant to abate sources of significant dust generation
<p>2 The following are normally considered to be the BAT for material delivery, storage and reclamation activities:</p> <ul style="list-style-type: none">• unloading hoppers for dusty materials should either be totally enclosed in a building equipped with filtered air extraction or the hoppers should be fitted with dust baffles and the unloading grids should be coupled to a dust extraction and cleaning system• water sprays (preferably using recycled water) should be used for dust suppression;
<p>3 Where fuel and raw materials are delivered by sea and dust releases could be significant, Applicants should use self-discharge vessels or enclosed continuous unloaders. Otherwise, dust generated by grab-type ship unloaders should be minimised through a combination of ensuring adequate moisture content of the material as delivered, by minimising drop heights and by using water sprays or atomised mist at the mouth of the ship unloader hopper.</p>
<p>Miscellaneous Techniques</p> <p>4 Where the material being conveyed may lead to significant dust releases, transfer points, vibrating screens, crushers, hoppers and the like should, where necessary be totally enclosed.</p>
<p>5 In order to prevent the spread of dust, windbreaks should where necessary be created</p>

by natural terrain, banks of earth or planting of long grass and evergreen trees in open areas. This not only has aesthetic benefits, but such vegetation is able to capture and absorb dust without suffering long-term harm. Generally, the technique of hydro-seeding can rapidly establish grass or other appropriate vegetation on waste tips, slag heaps or other apparently infertile ground.

Control of releases to water

6 Run-off of rain water from all open areas, but in particular from coal and raw materials stocking areas, will contain suspended solids. It should be intercepted and the suspended solids removed by settlement or other techniques. Arrangements should be made for monitoring the quality of the water discharged from the storage and blending areas where such discharges are in the vicinity of potentially vulnerable receptors.

Control of releases to land

7 Applicants should demonstrate that the potential risks of contamination of land by deposition of dust, leachate or run-off water are not significant or make appropriate provisions under Section 5. Similarly, they should demonstrate compliance with guidance on groundwater protection, when published.

2.1.2 NO_x Control (Primary measures)

The most important oxides of nitrogen with respect to releases from combustion processes are nitric oxide (NO), nitrogen dioxide (NO₂) and nitrous oxide (N₂O). NO and NO₂ are commonly referred to as NO_x. Nitric oxide forms over 95% of the total NO_x in emissions from most types of combustion plant. Higher proportions of NO₂ can be present in exhaust gases from gas turbines particularly modern gas turbines with dry low NO_x burner technology. Atmospheric fluidised bed operations produce higher levels of nitrous oxide than other types of combustion plant.

There are three recognised NO_x formation mechanisms:

- "fuel NO_x " by conversion of chemically bound nitrogen in the fuel;
- "thermal NO_x " by fixation of nitrogen in the combustion air;
- "prompt NO_x " by a mechanism in which molecular nitrogen is converted to NO via intermediate products in the early phase of the flame front with hydrocarbons participating in the reactions.

The first two mechanisms are the only ones of major importance in most combustion plants.

Fuel NO_x formation is dependent on the oxygen level in the vicinity of the flame. Reducing oxygen levels is thus important in reducing fuel NO_x . Fuel NO_x is most important in coal fired and biomass fired combustion systems, as these fuels have a higher fuel N content than other fuels.

Thermal NO_x formation requires high temperatures. Where combustion processes operate with peak temperatures of <1000°C thermal NO_x emissions will be of lower significance. Reducing peak temperatures reduces thermal NO_x formation. The thermal NO_x formation route is the most important source of NO_x in emissions from oil and gas fired plant. Fuel NO_x can be more important than thermal NO_x when using coal and some high nitrogen fuel oils or biomass.

Baseline NO_x emissions from unabated internal combustion engines vary with engine size and speed (RPM). Larger lower speed engines will produce more NO_x than smaller high speed engines. Similarly NO_x emissions from unabated gas turbines are generally a function of engine load, combustor temperature and size.

Combustion modifications

The application of combustion modifications is limited by operational and fuel specific parameters, that influence the safe operation of plant, such as:

- ignition stability at the burner,
- change in flame shape,

- ❑ problems of corrosion and erosion,
- ❑ incomplete burnout of the fuel,
- ❑ increase in CO emissions,
- ❑ change in flue gas temperature, and
- ❑ changes in the water-steam circuits.

As a result of the likely changes in one or more of these parameters, it should be noted that the suitability and choice of a primary measure and the resulting effects may not be directly transferable from one type of plant to another.

For further information concerning the regulatory framework applicable to large coal and oil fired power stations in England and Wales, refer to “Controls on Releases of Oxides of Sulphur and Nitrogen from Coal and Oil Fired Power Stations” at: <http://www.environment-agency.gov.uk/business/444304/444367/972464/?version=1&lang=e>.

2.1.2.1 Large Boilers and Furnaces

Combustion modification techniques include:

NO_x control by operational adjustments

The level of excess (above stoichiometric) air used can often be reduced, resulting in reduced NO_x emissions. Care must be exercised in ensuring that carbon monoxide and carbon in ash levels are not allowed to rise to unacceptable levels. Particulate emissions may also increase and thermal efficiency may be affected. It is possible for a 20-30% reduction in NO_x emissions to be achieved on some plants by these means before emissions of un-reacted material become excessive (e.g. at 6% carbon in ash for pulverized fuel firing). All new plant should be designed to take account of these characteristics.

A second operational change may be possible on large multiple burner boilers. If upper burners are not in use for firing fuel, they may be used to supply air only. In effect air staging is created. This is not as effective as purpose designed over fire air (OFA) systems. This technique is most suitable for gas and oil-fired boilers.

In boilers, which use preheated combustion air (up to 300°C) reduction in the levels of air preheat used will reduce emissions of NO_x. However there will be some reduction in thermal efficiency. This technique is used largely on gas-fired plant.

Low NO_x burners should be fitted to all new plant and retrofitting to existing plant should normally be expected. Low NO_x burners are effective in reducing NO_x emissions by 30-50% on average when compared to standard burners fitted on existing plant. Increased carbon monoxide and carbon in ash emissions have been noted on commissioning some Burners. Advanced low NO_x burners are now available that can achieve a further 20% reduction compared with first generation low NO_x burners with less impact on burnout.

Retrofitting low NO_x burners may require other modifications to be made to the combustion plant e.g. mills and air/wind box alterations and may not be possible in some instances. Low NO_x burners are also available for boilers firing oil or gas. They are highly effective for gas firing but there is a tendency to generate particulates when firing heavy fuel oil.

Over-fire air (OFA)

This technique involves introducing air above the primary combustion zone in a boiler. In purpose designed systems air injection ports are installed at up to three levels above the primary combustion zone. The technique is best used in conjunction with low NO_x burners and may be applicable to small as well as large boilers. 15-25% of the total combustion air can be supplied as OFA. Stoichiometry as low as 20% air deficiency in the burner zone is used. The reduction of NO_x emissions attributable to the use of this technique is variable, dependent on the boiler type and design and the method of OFA application, and will normally be 10-25%. The use of this technique may result in increases in carbon monoxide and unburnt carbon emissions.

There would be an impact on BAT if carbon in ash levels rose to an extent which would affect ash saleability and alternative means of disposal were required.

Flue gas recirculation (FGR)

Recirculation of flue gas dilutes the combustion air, hence lowering peak flame temperatures and in consequence reduces the thermal NO_x produced. This technique is useful for gas and oil firing (distillate in particular), but is less effective for coal firing where a large proportion of NO_x produced is fuel derived.

When natural gas is the fuel, NO_x reductions of 30-60% are observed. On heavy fuel oil NO_x reductions of 10-20% are observed but particulate emissions may increase. This technique should be considered in the design of boilers. Space requirements may prevent its application to smaller designs. Retrofitting to some types of existing plant may be possible.

Reburn

This technique controls NO_x emissions by injecting part of the fuel input at a level above the main combustion zone in the boiler. In the fuel rich region so created the NO_x produced in main combustion zone is reduced. Up to 20% of fuel may be introduced this way and the fuel need not be the same as the primary fuel. Thus gas or oil might be the reburn fuel for a coal fired boiler. Gas has the distinct advantage that it is simpler to supply to the upper parts of boiler furnaces and of taking less time to burn-out. This technique will be most applicable to those boilers with sufficient path length for burn-out after the reburn fuel injection point (ie less highly rated furnace designs). This may make it less appropriate for smaller boilers.

Where suitable, this technique can be applied to both new and existing boilers. In combination with low NO_x burners this technique may achieve overall NO_x reductions of 50-75%. The NO_x reduction attributable to reburn alone is 20-40% for many conventionally fired systems, however Inspectors should note that the higher the initial concentration of NO_x, the more efficient reburn is at reducing NO_x emission levels.

For smaller scale combustion plant, for example plant regulated only as a result of aggregation or small (<100MW(th)) single units, the use of combustion modifications may be sufficient in the consideration of BAT for the control of oxides of nitrogen emissions.

2.1.2.2 Pressurised Fluidised Beds

Recent developments in pressurized fluidized bed combustion (PFBC) technology include:

- *Freeboard firing* – The injection of a small quantity of oil into the freeboard at part load increases the plant's efficiency and also maintains the conditions for selective non-catalytic NO_x reduction close to those valid at full load conditions.
- *Fly ash recirculation* – A fly ash recirculation system has been proven in a commercial scale 71 MWe unit. This enables the plant to achieve improved SO₂ emission reductions for a given quantity of sorbent feed. Improvements in combustion efficiency can also be achieved, which is particularly important for low reactive fuels.

A feature of this technology is the lack of thermal NO_x production. Furthermore, the use of ammonia injection is claimed to be able to reduce NO_x emissions (fuel bound NO_x) by 80% at full load conditions. SO₂ emissions are controlled by feeding a sorbent (limestone or dolomite) into the fluidized bed. Elevated pressures in the PFBC lead to a different process for capture compared to an atmospheric plant – retention of up to 99% has been achieved with a calcium to sulphur ratio of 2.8.

2.1.2.3 Turbine Engines

Combined cycle gas turbine (CCGT) plant are normally BAT for new gas turbine installations.

Dry low NO_x combustion should be BAT for all new gas fired turbines and is preferred to wet low NO_x combustion.

Low-emission combustors can be retrofitted to some existing gas turbines, but others may be more economically completely replaced with new higher-efficiency, lower-emissions models.

Additional NO_x formed by supplementary firing of gas in the exhaust of a gas turbine using a well-designed and adjusted burner can be much less than would be expected by firing in air. In some cases it may be as little as 15% of the 'NO_x from SF' given in Annex 1 of CIGN IPR 1/2. This technique is often used in CHP schemes to vary the ratio of heat to power produced. It is particularly environmentally advantageous, having a high incremental thermal efficiency and low environmental impact. This very low NO_x emission is not achieved with auxiliary firing when the gas turbine is not running.

2.1.2.4 Reciprocating Engines

Traditionally engines were operated around stoichiometric air/fuel mixture ratios, slightly weak, giving good combustion efficiency. However the combination of high temperatures and oxygen availability gives maximum NO_x emissions. Operating an engine at air fuel ratios away from the stoichiometric reduces NO_x production. In the rich case, NO_x is reduced primarily by reducing the available oxygen, however this also reduces the oxygen available for the complete combustion of hydrocarbons. Operating an engine with a lean burn strategy reduces local temperatures by dilution and ensures there is ample oxygen for good hydrocarbon conversion. Lean burn engines are stratified charge engines since the air fuel mixture is too lean to ignite satisfactorily.

In SI engines a rich zone is produced around the spark to promote ignition with the mixture becoming progressively leaner away from the spark ignition point. These lean burn SI engines, fuelled by gas, use a high pressure injection of the pilot charge which is ignited by the spark.

Low NO_x emissions from both SI and CI engines can be achieved by combustion modification. The application of the techniques described below is, however, limited by engine design, plant operation and certain fuel parameters. The suitability and choice of a primary measure may not be directly transferable from one engine to another (or between SI – CI engines). Combustion modification techniques are discussed below;

Reduction of Charge Temperature by the Addition of Water (CI Engines)

The effect of introducing water into an engine is to lower the peak temperature. Water may be introduced directly by separate injection into the cylinders or the charge air may be humidified. The fuel can be introduced as an emulsion to the cylinders. Direct injection may reduce NO_x output by up to 60%, humidification of the charge air by 20%.

The use of emulsified fuels can lead to a reduction in NO_x production of 20%. The use of these techniques is, however, limited to CI engines and also by numerous problems which make their introduction impractical in most circumstances.

Tuning for NO_x (Ignition Timing)

The NO_x levels in the exhaust of a gas engine are a function of several things; the key criterion is, however, for a given engine design, timing angle, i.e. the number of degrees before top dead centre (deg. BTDC) at which ignition occurs.

In general, reducing the timing angle reduces the level of NO_x in the engine exhaust, however it also has two other effects. Firstly it reduces engine efficiency and secondly, as NO_x levels fall, the levels of other pollutants, CO and VOCs, rise.

The level of NO_x achievable by reducing the timing angle varies for different engines and designs. Given the impact of reduced timing angle on efficiency (and on other engine

parameters) engines tend to be tuned at settings that produce higher NO_x in the exhaust. Typically engines have been tuned so as to produce the highest efficiency possible (and therefore biggest impact in respect of CO₂ reduction). Existing engines typically produce NO_x levels of 1000-500 mg/Nm³ at 5% O₂, newer engines are capable of 500-250 mg/Nm³ at 5% O₂

Reducing timing angle reduces NO_x levels in the exhaust and engines fall into three categories as follows:

Engines that cannot operate down to 500mg/Nm³ (@ 5% oxygen). There is a whole range of engines that, because of their older design, these engines typically operate at around 1000mg/Nm³ (@ 5% oxygen); some can when de-tuned run at around 600mg/Nm³ (@ 5% oxygen).

Engines that can operate at 500mg/Nm³ (@ 5% oxygen). Some engines when de-tuned can operate at this exhaust NO_x level or just below, however they are unable to operate in a stable condition below approximately 400mg-450mg/Nm³ (@ 5% oxygen).

Engines that can operate at 250mg/Nm³ (@ 5% oxygen). In the last two years it has been possible to obtain certain sizes of engine from specific manufacturers that can operate successfully at this lower exhaust NO_x level.

Engines supplied from manufacturers to clients in the UK (and the rest of the EU), until 2002/33 were generally built to comply with the German TALUFT standard of 500mg/Nm³ (@5% oxygen). Whilst some engines as tuned do not operate at this level, in general all lean burn engines from this period can be re-tuned.

The use of SCR for gas fuelled SI engines is relatively unproven, SI engine exhausts are prone to rapid fluctuations in pressure which is known to destroy the SCR catalyst.

Reduced Efficiency

This is encountered whenever engine exhaust NO_x levels are reduced. The impact on efficiency which presents as an increased fuel consumption is typically 1-2% for a 250mg/Nm³ (@ 5% oxygen) reduction in exhaust NO_x. However for some engines the impact can be higher at 2-3% for an equivalent reduction. Some engines can only achieve the lower exhaust NO_x levels by being, effectively, depowered, i.e. reducing the electrical output, and this can have a very damaging effect on economics and CO₂ reduction. It can also cause operational problems and raise issues over manufacturers warranty.

Increased levels of CO and VOCs

These will be produced when engines are tuned for low NO_x, thus in removing or reducing one problem it is possible to create another which then, potentially, requires attention. Emissions of CO can be reduced by the addition of a catalytic converter in the exhaust (note that catalysts are prone to poisoning in engines fired by gases other than natural gas eg landfill) Typically reducing NO_x levels by around 350mg/Nm³ (@ 5% oxygen) increases CO by around 100mg/Nm³ (@ 5% oxygen).

Fuel/Air Mixing Improvements (CI Engines)

Multi-hole injectors are used to improve fuel mixing and distribution. Certain engine manufacturers also use multiple injectors in each cylinder to achieve improved mixing. Some designs may result in a 30% reduction in NO_x emissions. This combination of features is generally only available on new engines, however it should be possible for multiple discharge injectors to be retrofitted to existing engines.

Reduction of Air Manifold Temperature

The temperature of the air charged into the cylinders may be reduced by increased after-cooling. It is suggested that many engines may be run with an air charge temperature of approximately 40°C. The effective reduction in NO_x may be up to 15% based on a typical CI engine. This technique should be applicable to both existing and new engines. To avoid

in-cylinder corrosion problems, a minimum manifold temperature of 38°C must be maintained.

Exhaust Gas Recirculation (EGR)

By recycling exhaust gas into the air inlet, more inert mixture is fed into the engine which tempers local high temperatures and reduces NO_x emission. This reduces engine output and combustion efficiency. A recirculation level of about 5-10% has been found to halve the NO_x emissions. This method of NO_x reduction is not recommended for lean burn engines. EGR reduces full load efficiency and reduces the lean combustion limit.

2.1.2.5 Plaster Processes

In installations manufacturing plaster from gypsum, the combustion gas stream is intentionally diluted with additional air in order to provide – for example – a transport medium for dried and calcined material and a heat transfer medium which interacts directly with individual particles. For effective process performance therefore, the oxygen content of exhaust gases often approaches ambient levels.

For such installations however, the excess air should be minimised.

Indicative BAT requirements for the control of emissions of NO _x
Refer to the BAT box in Section 2.2.2

2.1.3 Primary Measures for SO₂ Control

Reduction of oxides of sulphur emissions

During combustion the major oxide of sulphur produced is sulphur dioxide (SO₂). However for solid and liquid fuels 1-3% of the sulphur will be oxidized to sulphur trioxide (SO₃). The presence of transition metals in the fuel will tend to catalyze this oxidation. Techniques employed to reduce sulphur dioxide emissions will also reduce sulphur trioxide emissions, therefore separate techniques and achievable levels for trioxide are not proposed. Sulphur trioxide is adsorbed and reacts with ash particles in the flue gases. It is therefore more likely to pose a problem with low ash fuels (e.g. fuel oils) and its presence is an important contributing factor in acid smutting occurrences.

Fuel selection

The fuel sulphur content is the source of sulphur in emissions to air from combustion processes. Fuel selection needs to consider a wide range of quality parameters and is a complex issue. Applicants are reminded that in preparing the BAT case for their process, the S content of the selected fuel may have a significant impact.

For further information concerning the regulatory framework applicable to large coal and oil fired power stations in England and Wales, refer to “Controls on Releases of Oxides of Sulphur and Nitrogen from Coal and Oil Fired Power Stations” at: <http://www.environment-agency.gov.uk/business/444304/444367/972464/?version=1&lang=e>.

For smaller scale combustion plant, for example plant regulated only as a result of aggregation rules or small (<20MW(th)) single unit combustion plant, use of low sulphur fuels (ie less than 1.2 % S) may be sufficient in the consideration of BAT for control of oxides of emissions.

Coal sulphur content varies widely (range 0.1-3.5%). If coal is the selected fuel, flue gas desulphurisation (or a technique that delivers equivalent emissions) is required. Where life or size of the plant precludes FGD as BAT, then low sulphur coals should be used.

Combustion of coal will produce sulphur dioxide in the flue gas from the combustion plant up to the following levels if abatement is not used.

%w/w	S in coal SO ₂ mg/m ³ (at 6% residual O ₂ in the flue gas)
0.1	225
1	2250
2	4500
3	6750

For fuel oils, the Sulphur Content of Liquid Fuels (SCOLF) Regulations set limitations on the sulphur content of liquid fuels. A similar approach should be adopted to that used for coal fired plant.

Natural gas that meets the standard for acceptance into the National Transmission System is considered to be a sulphur free fuel. Natural gas that does not meet this standard and industrial gases (e.g. some refinery gas and gases from gasification plants) may contain sulphur compounds and may therefore require desulphurisation.

The sulphur content of biofuels can range widely, dependent upon the fuel used. For example straw and barley crops can contain between 0.2 and 0.7% sulphur whilst concentrations in willow are expected to be at round 0.06%¹.

For coal fired plant:

Coal cleaning technologies can be sub-divided into two major groups:

- chemical cleaning, and
- washing (physical/mechanical cleaning)

Chemical cleaning is still in development and is not considered to be an available technology. Coal washing technology is well developed. Most techniques involve crushing coal to fine particle sizes and then separating inorganic (present as pyrites) and ash content from coal particles by a number of proprietary processes. Depending on the pyrites content, up to 50% of the original coal sulphur may be removed using these techniques. There is however a wider consideration with such processes, since extra energy is consumed, a water waste stream will be produced and a considerable amount of solids will remain for disposal. Coal cleaning usually takes place at the mine site.

For industrial gas fired plant:

A range of gas cleaning systems are available for the treatment of raw fuel gas. Many are well established and widely used in the oil, gas and chemicals industries for reducing the sulphur content of gas streams.

Components in the raw fuel gas containing sulphides are selectively absorbed and may be recovered as elemental sulphur by additional treatment, for example the recovery of hydrogen sulphide from amine scrubbing and conversion in a Claus kiln.

High temperature (hot) gas clean-up techniques are also in development. Thus where gasification is employed as an alternative to the direct combustion of coal, oil and oil emulsion fuels it should be possible to remove about 99% of the sulphur present in the original feedstock prior to the combustion of the gas.

In-furnace sulphur control

¹ R&D Technical Report P4-097/TR. Review of Power Production from Renewable and Related Sources

Emissions of sulphur dioxide from combustion plant can be reduced using in-furnace injection of sorbents. Fluidised bed combustion techniques are suited to this technique. In FBCs, between 10-15% of sulphur is retained in the ash as a result of reaction with calcium carbonate naturally present in the ash (cf about 5-10% retention in pulverised fuel or stoker boilers). Sulphur retention in the ash from the FBC may be increased to up to 90% by addition of crushed sorbent material (eg limestone) to the bed. Wider environmental considerations include the use of limestone and its disposal or possible uses of the ash streams, both the combustor bottom ash and the fly ash collected from the flue gas.

Dry sorbent injection may also be used with pulverised fuel furnaces, however the efficiency of SO₂ removal tends to be lower than with some other wet and dry FGD techniques at 80-95%

Indicative BAT requirements for the control of emissions of SO_x
Refer to the BAT box in Section 2.2.3

2.1.4 Environmental Performance Indicators

Benchmark values in this guidance are typically presented as concentrations (e.g. mg/l, mg/Nm³). Concentrations are the traditional basis for setting emission limits in permits as they are good indicators of unit operation performance but they have limitations. Thus, for England and Wales, the Environment Agency is developing complementary “Environmental Performance Indicators” that could help to target regulatory effort on the most important environmental issues.

Environmental Performance Indicators involve using emission data to:

- Normalise for the scale of process operation - to benchmark the emissions from installations that have different sizes and product mixes (e.g. quantity of emitted pollutant per unit of production).
- Calculate “Environmental Burdens” - using equivalency factors to determine the significance of emissions in terms of recognised environmental impacts.

Consideration is being given to a range of Environmental Performance Indicators, including:

For Air:

Stratospheric Ozone Depletion,
Global Warming (both from the installation and from imported power),
Photochemical Ozone Creation,
Airborne Acidification.

For Water:

Acidification,
Oxygen Demand,
Eutrophication.

For Waste:

Waste Hazard Score (from H1),
Waste Disposal Score (from H1).

For raw materials:

Water use (potable and non-potable).

For hazardous substances:

Environmental Health,
Human Health.

In the absence of any guidelines for the calculation of Environmental Performance Indicators, there are no indicative BAT requirements. However, Operators in England or Wales should demonstrate to the Environment Agency that they have their own methods of monitoring and benchmarking their environmental performance and show how these are used to drive environmental improvements.

The choice of Environmental Performance Indicators is left to Operators but they should give consideration to the issues that are listed above. The H1 database tool is advocated as providing a simple solution.

In future the Environment Agency may recommend specific methodologies for calculating Environmental Burden and/or normalising for scale. Research projects are currently under way to develop these systems.

2.2 EMISSIONS CONTROL

2.2.1 Point source emissions to air

The nature and source of the emissions expected from each activity is given in previous sections and the inventory of emissions should be confirmed in detail in the Application.

2.2.2 Abatement of nitrogen oxide emissions

End-of-pipe flue gas technologies to reduce NO_x emissions rely on the injection of ammonia, urea or other compounds to react with the NO_x in the flue gas and reduce it to molecular nitrogen. These secondary abatement measures can be divided into:

- Selective catalytic reduction (SCR), and
- Selective non catalytic reduction (SNCR)

The EU BAT Reference Document for Large Combustion Plant provides a detailed overview of these technologies and their applications.

Presently, there are few UK applications of these technologies

Selective catalytic reduction (SCR)

SCR reduces NO and NO₂ to N₂ with the addition of ammonia or urea solution in the presence of a catalyst at 300-400°C. SCR plant has been operated in high dust, low dust and tail end locations in the flue gas stream, however it may be positioned after an exhaust gas de-sulphurisation plant, if required. The latter arrangement would normally require an exhaust gas reheating stage and may take up as much as 2% of the electric capacity.

The potential for NO_x removal depends on the system design, catalyst activity and the concentration of reacting gases, but can be in excess of 90%, although actual performance figures of between 80 and 90% are more common.

SCR is available, and is used on combustion plants from <50 MW(th) to 1000 MW(th).

The use of SCR for GTs can achieve ultra low NO_x emissions (<10 mg m⁻³ at 15% O₂) but remains restricted largely to areas of poor air quality. Catalytic combustion is in commercial development for some types of GT.

The use of selective catalytic reduction (SCR) requires the storage of liquid ammonia or ammonia solution.

Selective non-catalytic reduction (SNCR)

SNCR reduces NO_x emissions by chemically reducing them to nitrogen and water through the injection of NH₂-X compounds into the furnace. SNCR is operated without a catalyst at

a temperature of 850 to 1100°C. The temperature window and residence time can strongly influence the reagent used (ammonia, urea or caustic ammonia).

Ammonia tends to give rise to lower nitrous oxide formation however urea may be more effective over a slightly larger temperature window and is easier to handle. Abatement efficiencies of up to 80% have been claimed although efficiencies of 30-50% are more typical^[BREF 2003]

SNCR also requires a sufficient retention time for the injected reagents to react with NO. Reagent distribution/injection must therefore be optimized and computational fluid dynamics modeling may be useful, and essential for all new plant.

Forms of SNCR have been successfully operated at lower temperatures in both CFBC and PFBC systems.

Indicative BAT requirements for the abatement of emissions of NOx
1 Emissions of NOx should be controlled in plant by a combination, as applicable, of : <ul style="list-style-type: none">• Combustion control systems• Combustion temperature reduction• Low NOx burners• Over fire air (OFA)• Flue/exhaust gas recycling• Reburn• SCR• SNCR
2 For coal and oil-fired plant, low NOx burners are required where applicable.
3 Existing coal-fired plant above 100 MWth should have over fire air (or equivalent).
4 New natural gas-fired gas turbines should use dry low NOx burners; existing natural gas fired gas turbines may use water/steam injection or conversion to DLN .
5 SCR or SNCR for smaller plant (<100 MW) is considered BAT where required to meet air quality standards or other environmental standards.
6 For new coal and oil fired plant above 100MW, SCR or primary measures to achieve equivalent NOx levels, is BAT.
7 Only combustion optimisation and SCR are feasible on >500MW PF plant firing low volatile coal. In these cases SCR would be required for new plant , a site specific assessment would be required for existing plant

2.2.3 Sulphur dioxide abatement

For large coal-fired plant, end-of-pipe flue gas desulphurisation (FGD), or equivalent techniques are considered BAT. There is a range of applicable FGD techniques available. When considering the appropriate technique the BAT assessment should include the quantities of raw material (e.g. limestone) consumed and the production of residues, possibly as waste, to the reduction in sulphur dioxide emissions. In considering abatement systems, removal efficiency should be considered as “the ratio of sulphur not emitted over a given period to the sulphur in the fuel over the same period.” This may also be known as the “Rate of desulphurisation”. The given period will be when the FGD plant is ‘Available’ for use and excludes start up and shutdown periods.

Wet limestone scrubbing

Existing FGD plant in the UK - at 500-600 MWe scale - has about 90-92% efficiency for sulphur dioxide abatement (depending on coal sulphur content). The byproduct is gypsum. BAT assessment considerations include additional wastewater streams and

disposal of the products. The hydrogen chloride content of flue gas will be captured in the scrubber liquors and will be purged from the liquor in the wastewater stream. The efficiency of sulphur dioxide removal may be increased up to 92-98% (BREF reference), however the buffers used to assist in the control of the water chemistry of the process may increase problems with waste-water treatment from scrubbing plant. This technique represents BAT for large coal-fired combustion plants above 100 MWth scale and large CI engines, using high sulphur residual/fuel oils, which have the potential for high sulphur dioxide emissions – unless limited operation renders it uneconomic.

Sea water scrubbing

This technique may be BAT for those large combustion plants situated on the coast. Sulphur dioxide removal efficiencies up to 98% are reportedly possible, however design of the reheat system may introduce constraints on sulphur dioxide removal efficiency if a bypass is required. The BAT assessment must consider the localised effect of the additional sulphate, chloride and heavy metals released to the sea and the effect of elevated water temperatures.

Spray dry scrubbing

This technique has been used on both coal and oil fired systems. Sulphur dioxide removal efficiencies of 70 to 95% have been achieved. The technique has the advantage that the wet scrubbing medium is dried by the hot flue gases. This results in a dry residue and an aqueous waste steam is not produced.

Dry sorbent scrubbing

This technique produces a solid residue, which has some uses. The BAT assessment would need to identify the uses for the residue. Sulphur dioxide removal efficiencies up to 80-95% are possible depending on the abatement process and the quantity of sorbent used. The sorbent may be lime, limestone or some other material. The treated gas will need to be passed through a fabric filter to remove alkaline dusts. The presence of a filter coated with alkaline dust will provide additional contact for the gases, enhancing the scrubbing effect.

Indicative BAT requirements for the abatement of emissions of SO ₂
.
1. Use of low sulphur fuels is a primary measure
3 For large coal or oil fired plant, limestone - gypsum or seawater flue gas desulphurisation is considered BAT.
4 Dry sorbent injection should be considered for pulverised and liquid fuel furnaces where too small to justify FGD
5 For Fluidised Bed Combustors, in-bed sulphur capture should be considered.
6 IGCC should be considered for new large scale solid and liquid fuel fired plant

2.2.4 Abatement of particulate matter emissions

The final efficiency of particulate removal from any combustion process should be as high as practicable, noting that abatement of particulate, especially of the finer fractions, is a significant method of controlling the release of heavy metals, dioxins and polynuclear aromatic hydrocarbons (PAHs).

Solid and liquid fuel fired plants can all give rise to particulate matter. Gas fired plant using natural gas will not generally require particulate control. Some industrial gases contain particulates and should be filtered on production or, if that is not possible, before combustion.

Where particulate abatement is required, the options include:

- Electrostatic Precipitators (ESPs)
- Fabric Filters
- Ceramic Filters
- Wet Scrubbers, or
- Cyclones

The BREF on waste water and waste gas treatment, A1 (flaring etc), A2 (Solvent vapour emissions), A3 (particulate and trace gas removal) & Pt B guidance provide a detailed overview of these devices and their application.

The best available techniques for removing suspended particulate matter from the combustion waste gases, such as electrostatic precipitators, bag filters or ceramic filters can maintain removal efficiencies of 99.5% over long periods provided that good control instrumentation and maintenance are employed.

For CI engines, the removal efficiency is very dependent upon fuel quality. Bag filters or ceramic filters are capable of reducing particulate emissions below 10 mg/m³. For many CI engine sites particulate abatement equipment may not be required. New CI engines should be capable of achieving the given unabated release levels.

Electrostatic precipitators

Electrostatic precipitators, equipped with programmable logic control systems to continually monitor and optimise their performance, can be designed to achieve levels consistently below 25 mg/m³ even with only two or three fields. This will be applicable to EPs located downstream of FGD, where FGD is not fitted levels of 50mgm⁻³ should be achieved.

For further information concerning the regulatory framework applicable to large coal and oil fired power stations in England and Wales, refer to "Controls on Releases of Oxides of Sulphur and Nitrogen from Coal and Oil Fired Power Stations" at: <http://www.environment-agency.gov.uk/business/444304/444367/972464/?version=1&lang=e>.

Performance is affected by ash resistivity and for combustion plant using low sulphur fuels it is possible to maintain abatement performance by controlled injection of sulphur trioxide upstream of the precipitator.

Electrostatic precipitators are used in both solid and liquid fuelled combustion plants and are available for small and large-scale combustion plant.

Fabric Filters

Bag (fabric) filters are proven and when correctly operated and maintained provide reliable abatement to below 10mg/m³ and are likely to be BAT for many applications. Although they cannot generally be used at temperatures over 250°C.

In oil fired plant, they have been used successfully in a number of installations using a pre-coat on the bags of lime or ash to adsorb any oil carryover. Bags in oil fired plant need to be cleaned less often than with other fuels and fresh coating material must be injected to coincide with cleaning cycles. The use of filters in this way must also be done in conjunction with maintaining good combustion control.

The benefits of moving to bag filter technology are:

- positive, high integrity, membrane separation of process and environment
- many filter fabrics can achieve better than 10 mg/m³
- less susceptible to variations in load

- better removal of sub-micron fume
- permits the more effective use of alkali injection for acid gas abatement and activated carbon for the abatement of dioxins, if required, on smaller scale combustion plant

Good temperature control is required to prevent thermal damage to bags and blinding by the condensation of moisture.

Ceramic filters

Ceramic filters are available for small combustion plant and are being developed for larger plant. They can normally achieve reliable levels below 10 mg/m³, which can be guaranteed at that level and have low maintenance requirements. Ceramic filters are able to withstand high temperatures, around 800-900°C compared with 120-270°C for fabric filters depending on the fabric. Operating temperatures are usually limited by the housing rather than the filter media.

Indicative BAT requirements for the abatement of emissions of particulate matter

1. For coal and oil-fired plant above 100 MWth, electrostatic precipitators are required. At smaller scale plant, other methods may be acceptable to meet emission limits.
2. For 'opted in' plant: FGD is BAT, and therefore particulate abatement is FGD + EP
3. For large (>100 MW) existing plant and where FGD is not required (not 'opted in') EP is BAT.
4. Where low sulphur fuel is used with plant fitted EPs, sulphur trioxide injection should be used to improve particulate control.

2.2.5 Other releases

Abatement of carbon dioxide (CO₂), carbon monoxide (CO) and volatile organic compounds (VOC)

All measures to reduce fuel use will also reduce CO₂ emissions. The selection, when possible, of raw materials with low organic matter content and fuel with a low ratio of carbon content to calorific value reduces CO₂ emissions.

Carbon dioxide removal is under development and there are significant research and demonstration projects worldwide. However, disposal of CO₂ from energy-generating plants is not considered to be an available technique at present. Nonetheless, conceivable future options in the UK include use in enhanced oil recovery and disposal in exhausted gas and oil reservoirs.

Elevated CO and VOC emissions are indicative of poorly controlled combustion and may be indicative of elevated releases of other pollutants. Accordingly good combustion conditions are required to minimize releases.

Some techniques employed to reduce NO_x emissions, such as combustion with lower excess air or strong air staging, may increase carbon monoxide and VOC emissions. In these circumstances particular attention is needed to the effective control of fuel and air in the combustion system.

Where necessary, the use of catalytic oxidation in the exhaust gas stream will enable carbon monoxide emissions to be reduced to low levels (< 100 mg/m³).

Abatement of metals and their compounds

The largest proportion of metals and compounds released to air are included in the composition of particulates released to air. Their release to air is therefore best controlled by minimizing particulate release levels and by selecting residual fuel oils with a low ash

content. Mercury and boron have a significant proportion of their emission in the vapour phase.

For oil and oil emulsion fuels, releases of nickel and vanadium may be highly significant, whilst a number of other metals and compounds may also be released. For coal, releases of arsenic, barium, boron, cadmium, chromium, copper, lead, manganese, mercury, molybdenum, nickel, selenium, vanadium and zinc may be significant. Note that some fuels may contain other metals such as antimony, cobalt, iron, tin, thallium and silver. It should be noted that vapour phase mercury and other heavy metals will be partially removed from flue gases during flue gas desulphurisation when using a wet scrubbing system.

The BREF on Water & Waste Gas Treatment provides a detailed overview the most commonly used control techniques to reduce emissions of metals.

Abatement of halogen emissions

Hydrogen chloride and hydrogen fluoride are produced during the combustion of coal and oil and some biofuels and waste derived fuels. Abatement techniques designed to remove sulphur dioxide will also result in much lower emissions of these gases. UK coal contains 0.1-0.6% chloride and therefore emissions of hydrogen chloride will be significant from larger unabated combustion plant. The BREF on Water & Waste Gas Treatment provides a detailed overview of techniques applied for the reduction of halogen emissions.

Abatement of PAH emissions

Total PAH (unspecified) emissions for large coal and oil fired combustion plant are of the order of 10-100 ng.m⁻³ in the flue gas. Some PAH is associated with particles and thus particulate removal equipment will reduce emissions to air, although the ash and dust may be contaminated.

Abatement of dioxin emissions

Polychlorinated dibenzo-p-dioxins (PCDD) and polychlorinated dibenzofurans (PCDF), together referred to as "dioxins", from combustion processes can potentially be formed from the combustion of any carbon containing fuel in the presence of trace quantities of chloride.

Dioxins are usually present in both the particulate and vapour phases and accordingly measures to reduce particulate matter emissions will also significantly reduce emissions of these compounds. FGD systems can enhance dioxin removal as can some SCR systems employed for NO_x reduction. These systems should not be employed as primary measures to abate dioxins which should be at concentrations of below or close to the limits of current measurement and analysis techniques.

Control of visible plumes

Plume visibility is largely dependent upon particle size, reflectivity and lighting, visible plumes may be possible even if BAT emission benchmarks are being met. Visible particulate plumes would not be expected from new plant, however.

Visible nitrogen dioxide plumes should not be permitted from new plant. However, plume visibility from the presence of NO₂ can be dependent on the plume dispersion and viewing position and visible plumes may still be possible even if BAT emission benchmarks are being met.

The need to minimize water vapour plumes should be considered. High moisture contents can also adversely affect plume dispersion therefore where practicable, water content of the exhaust stream should be reduced. Ideally the exhaust should be discharged at a temperature and moisture content sufficient to avoid saturation under a wide range of meteorological conditions, including cold damp weather.

The use of primary energy to reduce plume visibility is not considered BAT. However, it may be appropriate to use waste or recovered heat for this purpose. In these circumstances the BAT assessment should consider the benefits of this approach against the impacts.

Indicative BAT requirements for the control of point-source emissions to air

1 VOC and dioxins

These should be minimised through good combustion control.

2 The benchmark values for point source emissions to air listed in [Section 3.2.1](#) should be achieved unless alternative values are justified and agreed with the Regulator.

3 The main chemical constituents of the emissions should be identified, including VOC speciation where practicable.

4 Vent and chimney heights should be assessed for dispersion capability and an assessment made of the fate of the substances emitted to the environment (see [Section 4](#)).

Control of visible particulate plumes

5 Even where particulate benchmarks are already met, the aim should be to avoid visible emissions. However, because plume visibility is extremely dependent on the particle size and reflectivity, the angle of the light, and the sky background, it is accepted that, even when BAT is employed and very low emissions are being achieved, some plumes may still be visible under particular conditions.

Control of visible condensed water plumes

6 The need to minimise water vapour plumes should always be considered as, in addition to possible local visual amenity issues, in severe cases, plumes can cause loss of light, fogging, icing of roads, etc. High moisture content can also adversely affect plume dispersion so, where practicable, water content of the exhaust stream should be reduced. Ideally, the exhaust should be discharged at conditions of temperature and moisture content that avoid saturation under a wide range of meteorological conditions, including cold damp conditions.

7 The use of **primary energy** to reduce a plume simply because it is visible is not considered BAT. However, it may be appropriate to use **waste or recovered heat**, for example, heat in a gas stream prior to wet scrubbing can be used for re-heating the exhaust stream after scrubbing by means of a gas-gas heat exchanger. The use of energy for exhaust gas re-heat should be balanced against the benefits gained.

8 For cooling towers, plume abatement may be achieved by combining conductive heat exchange and evaporative cooling in the design of the tower. The degree of abatement required will depend upon local conditions and the distance from the towers to the nearest sensitive area. Any visible (condensed) plume should not ground beyond the boundary fence nor reach areas of habitation at a height that will cause significant loss of light.

2.2.6 Point source emissions to surface water and sewer

The nature and source of the emissions to surface water or sewer expected from each activity is given in previous sections and the inventory of emissions should be confirmed in detail in the Application.

As noted before, the primary consideration should always be to prevent releases of harmful substances to the aquatic environment, whether releases are direct or via a sewage treatment works, and only where prevention is not practicable should the release be minimised or reduced to the point where the emission is incapable of causing significant harm.

A wide variety of techniques is available for the control of releases to water or sewer, and the BREF on Common Waste Water and Waste Gas Treatment/ Management Systems in the Chemical Sector should be consulted as these generic techniques are considered

applicable to the combustion sector. Section 3.3 of the BREF has details of available water treatment techniques and Section 4.3.1 contains recommendations on what might constitute BAT for a variety of treatment techniques for releases to water.

In addition to the BREF and the techniques noted below, guidance on cost-effective effluent treatment techniques can be found in [Releases to water references](#). This includes IPC Technical Guidance Note A4 which summarises techniques of particular relevance .

Waste water can arise from the process, rain-water run-off where there is the potential for contamination, from storm water, from cooling water, from treating accidental releases of raw materials, products or waste materials, and from fire-fighting - and, where not insignificant, these should all be taken into account in the Application and in the Permit.

Where surface water and sewer control is needed, reference should be made to the General Sector Guidance.

The degree of on-site treatment required will normally vary depending on whether the discharge is to sewer or direct to a watercourse.

Process waters, site drainage waters, emergency fire water and chemically contaminated waters should, where appropriate, be contained and where necessary treated before release to controlled waters or sewer.

Areas where spillages are most likely, such as storage tanks and sampling points, should be banded. Bunds should:

- be impermeable;
- have no outlet and drain to a sump;
- contain all parts of the tank;
- be hydraulically tested on a regular basis;
- have a capacity at least 110% of the largest tank;
- where not frequently inspected, be fitted with a high level probe and an alarm as appropriate;
- have the fill points within the bund where possible.

The composition of any wastes collected should be checked prior to treatment or disposal. Rainwater collected from oil tank bunds should be discharged via an oil separator. Water from bunds of tanks containing other chemicals should not be disposed of via surface water drains or soakaways.

Tanks should have level gauges visible from the filling point. Pipework should preferably be overground. Where it must be underground it should be protected in a sleeve or a duct.

Releases to water may be direct, for example process effluent or cooling water, or indirect, for example, from plant surface water drains. In either case the water may contain relatively low concentrations of certain substances, but if large volumes of water are involved, the mass releases can be substantial. The following general principles should be applied in sequence to control releases to water:

- any use of water should be minimised, thereby minimising the amount of contaminated water to be dealt with;
- methods of avoiding or reducing contamination, or risk thereof, of process or surface water should be considered;
- water should be re-cycled within the process from which it issues, by treating it first if necessary. Where that is not practicable it should be re-cycled to another part of the process which has a lower water quality requirement;
- ultimately, surplus water is likely to need treatment. Generally any physico-chemical treatment will be more efficient on the more concentrated individual or similar effluent streams than treating the whole mixed effluent. However, the inherent properties of dissimilar waste streams can be usefully employed to avoid adding further chemicals, for example by balancing waste acid and alkaline streams to control the resultant pH. An exception to the preference for treating waste streams individually would be when biological treatment is proposed and

treatment of the whole mixed effluent overcomes an inhibitory effect of any individual waste stream.

For sites with large boilers and furnaces the following are the sources of waste streams to water which are likely to be the most significant:

Fuel storage and handling

Oil storage

Oil storage tanks should be bunded to provide at least 110% of the capacity of the largest tank. Road and rail tanker discharging areas should be hard surfaced and slope towards a drain leading to an interceptor with facilities for the removal of the oil. Oil tanks should normally be fitted with a high level alarm.

Decanted water from oil storage tanks and storm water from bunded areas should be drained to a water treatment plant, or directed to an appropriate disposal facility. Liquid effluents generated during periodic tank cleaning should be dealt with in a similar manner.

Water contaminated with oil should pass through oil removal facilities such as partition chambers or plate separators.

Coal storage

Leachate from coal stacks is governed by the coal composition. In particular the presence of pyrite (iron sulphide) in combination with a low pH can cause pollution of water courses. Acidic conditions may cause increased mobility of trace metals which may contribute to the polluting effect of the leachate. Where there is a significant risk of pollution of water or groundwater, leachate should be collected and treated .

Water treatment

De-ionisation effluent

Water de-ionisation plant regeneration effluent will usually be produced as an acid stream and an alkali stream which are mixed together and pH adjusted for disposal. This effluent contains effectively all the dissolved solids in the original water supply and any undissolved solids which may be present, particularly where river or estuary water is used. Soluble sulphates are also likely to be present where sulphuric acid is used for regeneration of the ion exchange material. The presence of salts in the release should be considered. All these liquors should be neutralised before discharge.

Boiler blowdown

During normal operations boilers are blown down to control the composition of the boiler water. This blowdown is a concentration of the small amounts of solids remaining in the boiler feed water from the water de-ionisation plant, plus chemicals used for the water treatment. These substances are mainly phosphates with possibly small amounts of alkalis, hydrazine, ammonia etc, used for pH control, de-aeration etc.

Process water (eg wet scrubbing)

The effluent from wet scrubbing will need chemical treatment, neutralisation and settlement before discharge. The acidity of the water can be adjusted by the addition of lime or other alkali. Treatment methods for removing cadmium and mercury include precipitating the metals either as hydroxides or sulphides followed by appropriate solids separation. This can remove up to 90% of most heavy metals but probably less than 70% of cadmium and nickel. Mercury is also difficult to remove in the presence of excess chloride but the use of activated carbon can remove up to 99%. The solids content, where necessary, should be controlled by settlement or filtration techniques. Sedimentation may suffice for easily settled solids, but filtration will almost certainly be necessary for separation of fine precipitates. Organics, including dioxins, furans and PAHs should be quantified in the treated effluent. At low levels they are normally most effectively treated in a biological plant, normally by the Sewerage Undertaker.

Discharge volumes for Sea Water Scrubbing make most treatment impracticable. Since contaminants are likely to be present in very low concentrations, effort should focus on minimising mass releases where practicable

Ash handling

Ashes should be handled in a solid state. Hydraulic transport of ashes produces a waste water stream, likely to contain metal salts and organic compounds. Where a market is available for the ash, appropriate handling techniques should be used.

Cleaning liquids

Wash waters and cleaning-out solutions containing organic acids, alkalis, alkali phosphates, iron oxides in suspension, complex corrosion inhibitors, hydrochloric, or hydrofluoric acid may be generated by boiler plant during maintenance. These liquors should be neutralised or treated to produce an acceptable waste before discharge or disposal. Controlled evaporative firing in the boiler has been used to limit the environmental impact of some of these wastes. However, this technique has not been applied widely and is still being developed.

Boilers require periodic cleaning to remove residual sediment and scale. Inspectors should satisfy themselves that the disposal of wastes produced is by an acceptable route.

Site drainage including rainwater

Site surface water from rain and deliberate washing down of surfaces, fire practices etc needs to be considered. Such water may be contaminated to a varying degree by oil and should go through an efficient oil/water separation/interceptor system. In some cases some or all may need further treatment to remove dissolved hydrocarbons.

Direct discharge to controlled waters should only be allowed where discharges will meet discharge requirements under all conditions which might reasonably be expected to occur.

Waste water treatment

Many sites will have on-site wastewater treatment plants for treating domestic wastes and suitable other streams. The effluent stream will need to meet discharge requirements as a minimum standard.

Cooling tower purge

Where evaporative cooling towers are used, biocides, most frequently chlorine or bromine based, lead to releases of prescribed substances to both air and water and their use should be minimised by optimising the dosing regime, (eg intermittent shock dosing or only dosing at critical times of the year). Chemical treatment of the main cooling water circuit may allow reduced use of chemical control.

The engineering of the biocide system should prevent accidental overdoses of biocide being released to the environment. This would involve monitoring of levels in the outgoing water and automatic operation of the final discharge valves, as well as bunding of storage vessels and adequate procedures.

Timber used in cooling towers is usually treated with CCA (copper sulphate, potassium dichromate, arsenic pentoxide), most of which remains well bound to the timber over its operating life, but initial surface residues can lead to significant levels in the purge water. Specifications for treated timber should include the requirement for controlled washing at the treatment site.

Indicative BAT requirements for the effluent treatment and the control of emissions to water
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1 The following general principles should be applied in sequence to control emissions to water:

- | |
|---|
| <ul style="list-style-type: none">• water use should be minimised and wastewater reused or recycled (see Section 2.4.3)• contamination risk of process or surface water should be minimised (see Section 2.2.6)• wherever possible, for small plant closed loop cooling systems should be used with procedures in place to ensure blow down is minimised. |
|---|

- In an integrated approach to cooling an industrial process, both the direct and indirect use of energy are taken into account. In terms of the overall energy efficiency of an installation, the use of once-through systems is BAT, in particular for processes requiring large cooling capacities (e.g. > 10 MWth). In the case of rivers and/or estuaries once-through can be acceptable if also:
 - extension of heat plume in the surface water leaves passage for fish migration;
 - cooling water intake is designed aiming at reduced fish entrainment;
 - heat load does not interfere with other users of receiving surface water.
 - where any potentially harmful materials are used measures should be taken to prevent them entering the water circuit

Consideration should be given to the use of filtration/osmosis or other techniques which allow the Effluent water to be cleaned for release or, preferably, for return to the process. Particular Consideration should be given to the fate of the concentrated residues of such techniques. These can often be returned to furnaces, evaporated, solidified, sent for incineration etc. Tankering of such residues off the site as waste, simply transfers the problem to another place unless they are sent to a facility with the genuine ability to recycle the materials.

2 If the pollutants in the wastewater are all readily biodegradable or the effluent contains only materials which are naturally occurring in much larger quantities in the receiving water, there may be justification for filtration/osmosis or similar techniques not being considered appropriate.

3 Where prevention is not possible, the emissions benchmarks given in [Section 3](#), should be achieved.

Where effluent is treated off-site at a sewage treatment works the above factors still apply. In particular, it should be demonstrated:

The treatment provided at the sewage treatment works is as good as would be achieved if the emission were treated on-site, based on reduction of load (not concentration) of each substance to the receiving water. (The [IPPC Environmental Assessments for BAT](#) software tool will assist in making this assessment.)

- that action plans are appropriate to prevent direct discharge of the waste-waters in the event of sewer bypass, via storm/emergency overflows or at intermediate sewage pumping stations - for example, knowing when bypass is occurring, rescheduling activities such as cleaning or even shutting down when bypass is occurring.
- that a suitable monitoring programme is in place for emissions to sewer.

5 There must be an understanding of the main chemical constituents of the treated effluent (including the make-up of the COD and the presence of any substances of particular concern to the aqueous environment). The fate of these chemicals in the environment should be assessed.

As a minimum, all emissions should be controlled to avoid a breach of water quality standards (see [Section 3.2](#) and [Section 4.1](#)), but where another technique can deliver better results at reasonable cost it will be considered BAT and should be used (see [Section 1.1](#)). Unless self-evident, calculations and/or modelling to demonstrate this should be carried out as part of the Application (in response to its Section 4.1 questions).

2.2.7 Point source emissions to groundwater

The Groundwater Regulations for the UK came into force on 1 April 1999, and an IPPC Permit will be subject to the following requirements under these Regulations.

- (i) The Permit shall not be granted at all if it would allow the direct discharge of a List I substance (Regulation 4(1)) - except in very limited circumstances (see Notes 1 and 2, below).

- (ii) If the Permit allows the disposal of a List I substance or any activity that might lead to an indirect discharge of a List I substance then prior investigation (as defined in Regulation 7) is required and the Permit shall not be granted if this reveals that indirect discharges of List I substances would occur. In any event, conditions to secure the prevention of such discharges must be imposed (Regulation 4(2) and (3)).
- (iii) In the case of List II substances, Permits allowing direct discharges or possible indirect discharges, cannot be granted unless there has been a prior investigation and conditions must be imposed to prevent groundwater pollution (Regulation 5).
- (iv) The Regulations contain further detailed provisions covering surveillance of groundwater (Regulation 8); conditions required when direct discharges are permitted (Regulation 9); when indirect discharges are permitted (Regulation 10); and review periods and compliance (Regulation 11).

The principles, powers and responsibilities for groundwater protection in England and Wales, together with the Environment Agency's policies on this, are outlined in the Environment Agency's document *Policy and Practice for the Protection of Groundwater*. This outlines the concepts of vulnerability and risk and the likely acceptability from the Regulator's viewpoint of certain activities within groundwater protection zones. These are categorised as:

(A) Prior investigation of the potential effect on groundwater of on-site disposal activities or discharges to groundwater. Such investigations will vary from case to case, but the Regulator is likely to require a map of the proposed disposal area; a description of the underlying geology, hydrogeology and soil type, including the depth of saturated zone and quality of groundwater; the proximity of the site to any surface waters and abstraction points, and the relationship between ground and surface waters; and the composition and volume of waste to be disposed of; and the rate of planned disposal.

The Environment Agency has produced a series of maps for England and Wales, which provide a guide to potential groundwater vulnerability. Source Protection Zones are intended to aid protection by defining annular zones around each major potable source, including springs, boreholes and wells, based on travel times.

(B) Surveillance - This will also vary from case to case, but will include monitoring of groundwater quality and ensuring the necessary precautions to prevent groundwater pollution are being undertaken.

Note 1 The Regulations state that, subject to certain conditions, the discharges of List I substances to groundwater may be authorised if the groundwater is "permanently unsuitable for other uses". Advice must be sought from the Regulator where this is being considered as a justification for such discharges.

Note 2 List I and List II refer to the list in the Groundwater Regulations and should not be confused with the similar lists in the Dangerous Substances Directive

Indicative BAT requirements for point source emissions to groundwater
1 In general, there should be no permitted releases to groundwater of either a direct or indirect nature.
2 If there are releases to groundwater and they are to continue, the requirements of the Regulations, as summarised above, must be complied with.

2.2.8 Control of fugitive emissions to air

On many installations fugitive or diffuse emissions may be more significant than point source emissions, and common examples of sources and causes are given in the BAT box below.

As part of the Application the Operator should identify and, where possible quantify, significant fugitive emissions to air from all the specific relevant sources listed above, estimating the proportion of total emissions that are attributable to fugitive releases for each substance. Where there are opportunities for reductions, the Permit may require the updated inventory of fugitive emissions to be submitted.

Indicative BAT requirements for fugitive emissions to air
<p>1. Dust - The following general techniques should be employed where appropriate:</p> <ul style="list-style-type: none">• Covering of skips and vessels• Avoidance of outdoor or uncovered stockpiles (where possible, particular consideration should be given to the nature and location of the stockpile in relation to sensitive receptors)• Where dust creation is unavoidable, use of sprays, binders, stockpile management techniques, windbreaks and so on• Regular wheel and road cleaning (avoiding transfer of pollution to water and wind blow)• Closed conveyors, pneumatic or screw conveying (noting the higher energy needs), minimising drops. Filters on the conveyors to clean the transport air prior to release• Regular housekeeping• Enclosed silos (for storage of bulk powder materials) vented to fabric filters. The recycling of collected material should be considered under Section 2.6. <p>Enclosed containers or sealed bags used for smaller quantities of fine materials</p> <p>Further options may include the appropriate combination of:</p> <ul style="list-style-type: none">• orientation of long stockpiles in the direction of the prevailing wind• installing wind barriers or using natural terrain to provide shelter• controlling the moisture content of the material delivered• careful attention to procedures to avoid unnecessary handling of materials and long unenclosed drops• adequate containment on conveyors and in hoppers, etc• rigorous maintenance standards for equipment• high standards of housekeeping, in particular the cleaning and damping of roads• use of mobile and stationary vacuum cleaning equipment dust suppression or dust extraction• and bag filter cleaning plant to abate sources of significant dust generation. <p>Where the material being conveyed, such as stock and ash, may lead to significant dust releases, transfer points, vibrating screens, crushers, hoppers and the like should, where necessary be totally enclosed and extracted to a bag filter plant. Central or local vacuum cleaning systems are preferable to washing down for removal of spillage, since the effects are restricted to one medium and recycling of spilt material is simplified.</p> <p>In order to prevent the spread of dust, windbreaks should where necessary be created by natural terrain, banks of earth or planting of long grass and evergreen trees in open areas. This not only has aesthetic benefits, but such vegetation is able to capture and absorb dust without suffering long-term harm. Generally, the technique of hydro-seeding can rapidly establish grass or other appropriate vegetation on waste tips, slag heaps or other apparently infertile ground.</p> <p>Routes used by site vehicles should be planned, where practicable. Points of access from the public highways should be minimised and wheel-cleaning equipment should be employed where necessary to prevent the carry-over of mud and dust on to public roads. Site roads should be to minimise the generation of dust clouds and vehicles should be restricted to these designated routes by fences, ditches or other means wherever practicable. Water-filled troughs should be used to slow trucks, wash wheels and keep roadways damp. Alternatively, dusty routes can be kept damp with water</p>

sprays,

2. VOCs

- When transferring volatile liquids, the following techniques should be employed – subsurface filling via (anti-syphon) filling pipes extended to the bottom of the container, the use of vapour balance lines that transfer the vapour from the container being filled to the one being emptied, or an enclosed system with extraction to suitable abatement plant.
- Vent systems should be chosen to minimise breathing emissions (for example pressure/vacuum valves) and, where relevant, should be fitted with knock-out pots and appropriate abatement equipment.
- Maintenance of bulk storage temperatures as low as practicable, taking into account changes due to solar heating etc.
- The following techniques should be used (together or in any combination) to reduce losses from storage tanks at atmospheric pressure:
 - Tank paint with low solar absorbency
 - Temperature control
 - Tank insulation
 - Inventory management
 - Floating roof tanks
 - Bladder roof tanks
 - Pressure/vacuum valves, where tanks are designed to withstand pressure fluctuations
 - Specific release treatment (such as adsorption condensation)

3. For Information on Odour, see [Section 2.2.6](#) .

4. VOC emissions are unlikely in this sector. In the event that VOCs control is needed, reference should be made to the General Sector Guidance.

2.2.9 Fugitive emissions to surface water, sewer and groundwater

As part of the Application, the Operator should identify and, where possible, quantify significant fugitive emissions to water, sewer or ground from all relevant sources, and estimate the proportion of total emissions that are attributable to fugitive releases for each of the main substances releases.

Some common examples of sources of fugitive releases to waters and their preventive measures are given in the BAT box below.

Indicative BAT requirements for fugitive emissions to water

1 For **subsurface structures**:

- establish and record the routing of all installation drains and subsurface pipework;
- identify all sub-surface sumps and storage vessels;
- engineer systems to minimise leakages from pipes and ensure swift detection if they do occur, particularly where hazardous (ie. Groundwater-listed) substances are involved;
- provide secondary containment and/or leakage detection for sub-surface pipework, sumps and storage vessels;
- establish an inspection and maintenance programme for all subsurface structures, eg. Pressure tests, leak tests, material thickness checks or CCTV

All sumps should:

- be impermeable and resistant to stored materials;
- be subject to regular visual inspection and any contents pumped out or otherwise removed after checking for contamination;
- where not frequently inspected, be fitted with a high level probe and alarm, as appropriate;
- be subject to programmed engineering inspection (normally visual, but extending to water testing where structural integrity is in doubt).

2 For **surfacing**:

- design appropriate surfacing and containment or drainage facilities for all operational areas, taking into consideration collection capacities, surface thicknesses, strength/reinforcement; falls, materials of construction, permeability, resistance to chemical attack, and inspection and maintenance procedures;
- have an inspection and maintenance programme for impervious surfaces and containment facilities;
- unless the risk is negligible, have improvement plans in place where operational areas have not been equipped with:
 - an impervious surface
 - spill containment kerbs
 - sealed construction joints
 - connection to a sealed drainage system

3 All **above-ground tanks** containing liquids whose spillage could be harmful to the environment should be banded. For further information on bund sizing and design, see the [Releases to water references](#).

Bunds should:

- be impermeable and resistant to the stored materials;
- have no outlet (that is, no drains or taps) and drain to a blind collection point;
- have pipework routed within banded areas with no penetration of contained surfaces;
- be designed to catch leaks from tanks or fittings;
- have a capacity greater than 110 percent of the largest tank or 25 percent of the total tankage, whichever is the larger;
- be subject to regular visual inspection and any contents pumped out or otherwise removed under manual control after checking for contamination;
- where not frequently inspected, be fitted with a high-level probe and an alarm, as appropriate;
- where possible, have tanker connection points within the bund, otherwise provide adequate containment; be subject to programmed engineering inspection (normally visual, but extending to water testing where structural integrity is in doubt).

4 **Storage areas for IBCs, drums, bags, etc**, should be designed and operated to minimise the risk of releases to the environment. In particular:

- Storage areas should be located away from watercourses and sensitive boundaries, (e.g.. those with public access) and should be protected against vandalism.
- Storage areas should have appropriate signs and notices and be clearly marked-out, and all containers and packages should be clearly labelled.
- The maximum storage capacity of storage areas should be stated and not exceeded, and the maximum storage period for containers should be specified and adhered to.
- Appropriate storage facilities should be provided for substances with special requirements (e.g. flammable, sensitive to heat or light) and formal arrangements should be in hand to keep separate packages containing incompatible substances (both "pure" and waste).
- Containers should be stored with lids, caps and valves secured and in place - and this also applies to emptied containers.
- All stocks of containers, drums and small packages should be regularly inspected (at least weekly).
- Procedures should be in place to deal with damaged or leaking containers.

2.2.10 Odour

The level of detail supplied should be in keeping with the risk of causing odour-related annoyance at sensitive receptors.

Where an installation poses no risk of odour-related environmental impact because the activities undertaken are inherently non-odorous, this should be justified and no further information relating to odour need normally be supplied.

Where odour could be a problem, the Operator will be required in the Application to supply the information as indicated below:

- Information relating to sensitive receptors, in particular the type of receptor, location relative to the odour sources and an assessment of the impact of odorous emissions on the receptors. Where detailed information is required the Operator may be able to secure an agreement to supply this as part of an Improvement Programme.
- An overview of any complaints received, what they relate to (source/operation) and remedial action taken. The types and source of odorous substances used or generated, intentional and fugitive (unintentional) release points and monitoring undertaken.
- Actions taken to prevent or minimise
 - A description of the actions taken to prevent and/or minimise odour annoyance or each odour source.
 - A demonstration that the indicative BAT requirements are being complied with.
 - Identification of any circumstances or conditions which might compromise the ability to prevent or minimise odour annoyance, and a description of the actions that will be taken to minimise the impact.

There may be a requirement placed upon the Operator to provide some or all of this information in the form of an odour management statement. See the [Odour management statement](#) for a typical log book.

Indicative BAT requirements for odour control
<p>1 The requirements for odour control will be installation-specific and depend on the sources and nature of the potential odour. In general:</p>
<p>2 Where odour can be contained, for example within buildings, the Operator should maintain the containment and manage the operations to prevent its release at all times.</p>
<p>3 Where odour releases are expected to be acknowledged in the Permit, (i.e. contained and treated prior to discharge or discharged for atmospheric dispersion):</p> <ul style="list-style-type: none">• For existing installations, the releases should be modelled to demonstrate the odour impact at sensitive receptors. The target should be to minimise the frequency of exposure to ground level concentrations that are likely to cause annoyance.• For new installations, or for significant changes, the releases should be modelled and it is expected that the Operator will achieve the highest level of protection that is achievable with BAT from the outset.• Where there is no history of odour problems then modelling may not be required although it should be remembered that there can still be an underlying level of annoyance without complaints being made.• Where, despite all reasonable steps in the design of the plant, extreme weather or other incidents are liable, in the view of the Regulator, to increase the odour impact at receptors, the Operator should take appropriate and timely action, as agreed with the Regulator, to prevent further annoyance (these agreed actions will be defined either in the Permit or in an odour management statement).
<p>4 Where odour generating activities take place in the open, (or potentially odorous materials are stored outside) a high level of management control and use of best practice will be expected.</p>
<p>5 Where an installation releases odours but has a low environmental impact by virtue of its remoteness from sensitive receptors, it is expected that the Operator will work towards achieving the standards described in this Note, but the timescales allowed to achieve this might be adjusted according to the perceived risk.</p>

2.3 MANAGEMENT

Within IPPC, an effective system of management is a key technique for ensuring that all appropriate pollution prevention and control techniques are delivered reliably and on an integrated basis.

The Regulators strongly support the operation of formal environmental management systems (EMSs). An Operator with such a system will not only find it easier to meet the BAT requirements for management of the installation but also many of the technical/regulatory requirements listed in other Sections of this Guidance.

The benefits of public environmental statements are recognised and their use is encouraged.

The Regulators recommend either certification to the ISO 14001 standard or registration under EMAS (EC Eco Management and Audit Scheme) (OJ L114, 24/04/01). Both certification and registration provide independent verification that the EMS conforms to an auditable standard. EMAS now incorporates ISO 14001 as the specification for the EMS element, and the Regulators consider that overall EMAS has a number of other benefits over ISO14001 - including a greater focus on environmental performance, a greater emphasis on legal compliance, and a public environmental statement. For further details about ISO 14001 and EMAS contact British Standards Institute (BSI) or the Institute of Environmental Management and Assessment (IEMA), respectively.

Whilst an effective EMS will help the Operator to maintain compliance with specific regulatory requirements and manage all significant environmental impacts, this section of the Guidance identifies only those EMS requirements that are not specifically covered elsewhere in the document. This Section should not, therefore, be taken to describe all of the elements of an effective environmental management system. The requirements below are considered to be BAT for IPPC, but they are the same techniques required by a formal EMS and so should be capable of delivering wide environmental benefits.

The European Commission has also set out its views on BAT and Environmental Management Systems in the form of standard text which will be included in all new and updated BREFs.

The Regulators are of the view that environmental management systems help to improve the management of environmental risks from an installation or activity. In England and Wales an EMS reduces the EP OPRA profile which is reflected in charging and compliance assessment planning.

Indicative BAT requirements for management techniques

Operations and maintenance

1 Effective operational and maintenance systems should be employed on all aspects of the process whose failure could impact on the environment, in particular there should be:

- demonstration of top management's commitment to, and role in, such systems
- documented procedures to control operations that may have an adverse impact on the environment
- a defined procedure for identifying, reviewing and prioritising items of plant for which a preventative maintenance regime is appropriate
- documented procedures for monitoring emissions or impacts
- a preventative maintenance programme covering all plant, whose failure could lead to impact on the environment, including regular inspection of major 'non productive' items such as tanks, pipework, retaining walls, bunds ducts and filters

2 The maintenance system should include auditing of performance against requirements arising from the above and reporting the result of audits to top management.

Competence and training

3 Training systems, covering the following items, should be in place for all relevant staff which cover:

- awareness of the regulatory implications of the Permit for the activity and their work activities;
- awareness of all potential environmental effects from operation under normal and abnormal circumstances
- awareness of the need to report deviation from the Permit
- prevention of accidental emissions and action to be taken when accidental emissions occur

4 The skills and competencies necessary for key posts should be documented and records of training needs and training received for these post maintained.

5 The key posts should include contractors and those purchasing equipment and materials;

6 The potential environmental risks posed by the work of contractors should be assessed and instructions provided to contractors about protecting the environment while working on site.

7 Where industry standards or codes of practice for training exist (e.g. WAMITAB) they should be complied with.

Accidents/incidents/non-conformance

8 There should be an accident plan as described in [Section 2.8](#) which:

- identifies the likelihood and consequence of accidents
- identifies actions to prevent accidents and mitigate any consequences

9 There should be written procedures for handling, investigating, communicating and reporting actual or potential non-compliance with operating procedures or emission limits.

10 There should be written procedures for handling, investigating, communicating and reporting environmental complaints and implementation of appropriate actions.

11 There should be written procedures for investigating incidents, (and near misses) including identifying suitable corrective action and following up

Organisation

The following are indicators of good performance which may impact on the Regulator's resources, but not all will necessarily be insisted upon as Permit conditions:

12 The company should adopt an environmental policy and programme which:

- includes a commitment to continual improvement and prevention of pollution;
- includes a commitment to comply with relevant legislation and other requirements to which the organisation subscribes; and
- identifies, sets, monitors and reviews environmental objectives and key performance indicators independently of the Permit.

13 The company should have demonstrable procedures (eg. written instructions) which incorporate environmental considerations into the following areas:

- the control of process and engineering change on the installation;
- design, construction and review of new facilities and other capital projects (including provision for their decommissioning);
- capital approval; and
- purchasing policy.

14 The company should conduct audits, at least annually, to check that all activities are being carried out in conformity with the above requirements. Preferably, these should be independent.

15 The company should report annually on environmental performance, objectives and targets, and future planned improvements. Preferably, these should be published environmental statements.

16 The company should operate a formal Environmental Management System. Preferably, this should be a registered or certified EMAS/ISO 14001 system (issued and audited by an accredited certification body).

17 The company should have a clear and logical system for keeping records of, amongst others:

- policies
- roles and responsibilities
- targets
- procedures
- results of audits
- results of reviews

2.4 RAW MATERIALS

This section covers the use of raw materials and water, and the techniques for both minimising their use and minimising their impact by selection. (Energy and fuels are covered under [Section 2.7](#), Energy).

As a general principle, the Operator will need to demonstrate the measures taken to:

- reduce the usage of all raw materials and intermediates ([Section 2.4.2](#))
- substitute less harmful materials, or those which can be more readily abated and when abated lead to substances that are more readily dealt with
- understand the fate of by-products and contaminants and their environmental impact ([Section 2.4.2](#))

2.4.1 Raw materials selection

This section looks at the selection and substitution of raw materials and [Section 2.4.2](#) describes the techniques to minimise their use.

It should be recognised that the process of selecting raw materials can present an opportunity to control emissions at source. In this regard it is suggested that Operators closely examine the range of possible raw material options available to them with a view to reducing the key impacts, identified as: SO₂, NO_x, Particulates, CO₂, Air Trace substances (dioxins/heavy metals).

The Operator should supply in the Application a list of the materials used which have potential for significant environmental impact, together with the following associated information:

- the chemical composition of the materials, where relevant;
- the quantities used;
- the fate of the material in the installation (ie. approximate percentages to each environmental medium and to the products);
- the environmental impact potential, where known (eg. degradability, bioaccumulation potential, toxicity to relevant species);
- any reasonably practicable alternative raw materials that may have a lower environmental impact (including, but not limited to any alternatives described in the BAT requirements below) on the substitution principle;
- and justification for the continued use of any substance for which there is a less hazardous alternative (eg. on the basis of impact on product quality) to show that the proposed raw materials are therefore BAT.

Indicative BAT requirements for material selection
1 The Operator should maintain a list of raw materials and their properties as noted above.
2 The Operator should have procedures for the regular review of new developments in raw materials and for the implementation of any suitable ones with an improved environmental profile.
3 The Operator should have quality-assurance procedures for controlling the impurity content of raw materials.
4 The Operator should complete any longer-term studies needed into the less

polluting options and should make any material substitutions identified.

2.4.2 Waste minimisation audit (minimising the use of raw materials)

The options for waste recovery and recycling are covered in [Section 2.6](#). Waste avoidance/minimisation, and the use of clean technologies, is a theme which runs throughout [Section 2.1](#) and [Section 2.2](#). This section deals with the systematic approach to look for other opportunities.

Waste minimisation can be defined simply as: *“a systematic approach to the reduction of waste at source, by understanding and changing processes and activities to prevent and reduce waste”*.

A variety of techniques can be classified under the term waste minimisation, from basic housekeeping through statistical measurement, to application of clean technologies.

In the context of waste minimisation and this Guidance, waste relates to the inefficient use of raw materials and other substances at an installation. A consequence of waste minimisation will be the reduction of gaseous, liquid and solid emissions.

Key operational features of waste minimisation will be:

- the ongoing identification and implementation of waste prevention opportunities
- the active participation and commitment of staff at all levels including, for example staff suggestion schemes
- monitoring of materials' usage and reporting against key performance measures

For the primary inputs to activities which are themselves waste activities, eg. incineration, the requirements of this section may have been met “upstream” of the installation. However, there may still be arisings that are relevant.

See the [Waste minimisation support references](#) for detailed information, guides and case studies on waste minimisation techniques.

Indicative BAT requirements for waste minimisation audits

1 The Operator should carry out a waste minimisation audit at least every 4 years. If an audit has not been carried out in the 2 years prior to submission of the application and the details made known at the time of the application, then the first audit shall take place within 2 years of the issue of the Permit. The methodology used and an action plan for reducing the use of raw materials should be submitted to the Regulator within 2 months of completion of the audit. The audit should be carried out as follows:

2 The Operator should analyse the use of raw materials, assess the opportunities for reductions and provide an action plan for improvements using the following three essential steps

- process mapping
- materials mass balance
- action plan

3 The use and fate of raw materials and other materials, including by-products, solvents and other support materials, such as fuels, catalysts and abatement agents, should be mapped onto a process flow diagram (see the [Waste minimisation support references](#)). This should be achieved by using data from the raw materials inventory and other company data as appropriate. Data should be incorporated for each principal stage of the operation in order to construct a mass balance for the installation.

4 Using this information, opportunities for improved efficiency, changes in process and waste reduction should be generated and assessed. An action plan should then be prepared for implementing improvements to a timescale approved by the Regulator.

2.4.3 Water use

Water use should be minimised within the BAT criteria for the prevention or reduction of emissions and be commensurate with the prudent use of water as a natural resource. Reducing water use is usually a valid environmental (and economic) aim in itself, but any water passing through an industrial process is degraded by the addition of pollutants so there is generally an increase in pollutant load. The benefits to be gained from reducing water input include:

- reducing the size of (a new) treatment plant, thereby supporting the BAT cost-benefit justification of better treatment;
- cost savings where water is purchased from or disposed of to another party;
- associated benefits within the process such as reduced energy requirements for heating and pumping, and reduced dissolution of pollutants leading in turn to reduced sludge generation in the effluent treatment plant (and consequent disposal costs).

The use of a simple mass balance for water use should help to reveal where reductions can be made.

Advice on cost-effective measures for minimising water can be found in the [Water efficiency references](#).

For cooling systems, refer to [Section 2.2.6](#).

Indicative BAT requirements for minimisation of water use
<p>1 The Operator should carry out a regular review of water use (water efficiency audit) at least every 4 years. If an audit has not been carried out in the 2 years prior to submission of the application and the details made known at the time of the application, then the first audit should take place within 2 years of the issue of the Permit.</p> <ul style="list-style-type: none">• Flow diagrams and water mass balances for the activities should be produced.• Water-efficiency objectives should be established, with constraints on reducing water use beyond a certain level being identified (which usually will be usually installation-specific).• Water pinch techniques should be used in the more complex situations such as chemical plant, to identify the opportunities for maximising reuse and minimising use of water (see the Water efficiency references). <p>Within 2 months of completion of the audit, the methodology used should be submitted to the Regulator, together with proposals for a time-tabled plan for implementing water reduction Improvements for approval by the Regulator.</p>
<p>2 The following general principles should be applied in sequence to reduce emissions to water:</p> <ul style="list-style-type: none">• Water-efficient techniques should be used at source where possible• Water should be recycled within the process from which it issues, by treating it first if necessary. Where this is not practicable, it should be recycled to another part of the process that has a lower water-quality requirement• In particular, if uncontaminated roof and surface water cannot be used in the process, it should be kept separate from other discharge streams, at least until after the contaminated streams have been treated in an effluent treatment system and been subject to final monitoring.
<p>3 Measures should be in place to minimise the risk of contamination of surface waters or groundwater by fugitive releases of liquids or solids (see Section 2.2.6).</p>

4 The water-quality requirements associated with each use should be established, and the scope for substituting water from recycled sources identified and input into the improvement plan.

Less contaminated water streams, such as cooling waters, should be kept separate from more contaminated streams where there is scope for reuse - though possibly after some form of treatment.

Most wastewater streams will however need some form of treatment (see [Section 2.2.6](#) for techniques) but for many applications, the best conventional effluent treatment can produce a water that is usable in the process directly or when mixed with fresh water. Though treated effluent quality can vary, it can often be recycled selectively - used when the quality is adequate, discharged when the quality falls below that which the system can tolerate.

5 In particular, the cost of membrane technology continues to reduce, and they can be applied to individual process streams or to the final effluent from the effluent treatment plant, as appropriate. In some applications in some Sectors, they can supplement (or possibly completely replace) the ETP plant so that most water is recyclable and there is a greatly reduced effluent volume. Where the remaining, possibly concentrated, effluent stream is sufficiently small – and particularly where waste heat is available - further treatment by evaporation can lead to zero aqueous effluent. Where appropriate, the Operator should assess the costs and benefits of using membrane techniques to minimise water usage and effluent discharge.

6 Water usage for cleaning and washing down should be minimised by:

- vacuuming, scraping or mopping in preference to hosing down;
- reusing wash water (or recycled water) where practicable;
- using trigger controls on all hoses, hand lances and washing equipment.

7 Fresh water consumption should be directly measured and recorded regularly at every significant usage point - ideally on a daily basis.

2.5 WASTE HANDLING

The Operator should list in detail the nature and source of the significant waste from each activity as the response to the emissions inventory requirement of the Application - though where there are a very large number of relatively small streams, some aggregation of similar and relatively insignificant waste streams may be appropriate.

Indicative BAT requirements for waste handling

Characterisation and quantification of each waste stream, and description of measures for waste management, storage and handling.

1 A system should be in place and maintained which records the quantity, nature and origin of any waste that is disposed of or recovered - and also, where relevant, the destination, frequency of collection, mode of transport and treatment method for those wastes.

2 Wastes should be segregated wherever practicable, and the disposal routes identified. Disposal should be as near to the point of generation as is practicable.

3 Records should be maintained of any waste sent off-site (Duty of Care).

4 All appropriate steps should be taken to prevent emissions from waste storage or handling (eg. liquid or solid spillage, dust or VOC emission, and odour).

5. Bottom ash and fly ash should be stored separately to provide flexibility to re-use the different ash fractions.

6. Where scale allows, ash fractions and Air Pollution Control residues (filters etc) should be stored in closed silos fitted with high level alarms and fabric filters.
7. All ash transport containers should be sealed or covered, unless by its nature there is no release caused by its transportation.
8. Other solid waste streams shall be collected in containers which are managed in a way to prevent the release of waste, dust or leachate

2.6 WASTE RECOVERY OR DISPOSAL

The Regulations require the Regulator, in setting Permit conditions, to take account of certain general principles, including that the installation in question should be operated in such a way that “waste production is avoided in accordance with Council Directive 75/442/EEC on waste; and where waste is produced it is recovered, or where this is technically or economically impossible it is disposed of, while avoiding or reducing the impact on the environment”. The objectives of the National Waste Strategies should also be considered.

Waste avoidance (minimisation) at source is addressed in detail in [Section 2.1](#) and related issues are addressed in the sections on abatement techniques (see [Section 2](#)). The specific requirement for a waste minimisation audit is noted in [Section 2.4.2](#).

To meet these requirements, Operators should provide the Regulator with the information requested in point 2 below.

Indicative BAT requirements for waste recovery or disposal
<p>Description of the way each waste stream is recovered or disposed of.</p> <ol style="list-style-type: none">1 Waste should be recovered, unless it is technically or economically impractical to do so.2 Where waste must be disposed of, the Operator should provide a detailed assessment identifying the best environmental options for waste disposal - unless the Regulator agrees that this is unnecessary. For existing disposal activities, this assessment may be carried out as an improvement condition to a timescale to be approved by the Regulator.3. For installations burning solid and some liquid fuels, ash will often be the major waste produced. Accordingly the Operator should consider alternative technically and economically feasible uses, for these. For example bottom ash can be used as an aggregate and PFA can be used in cement manufacture and for other construction products. Other by-product streams, such as FGD gypsum manufacture can also be used in the construction sector.4. Where disposal occurs, the Operator should justify why recovery is technically or economically not feasible.5. The Operator shall regularly audit the waste disposal /recovery routes to ensure that their waste is being properly handled and dealt with.7. Residues from the gasification of coal and oil are often in the form of a fused slags, which may be suitable as a construction material or for treatment to recover some of their metal content. In either case the fused form of the residues makes them less subject to leaching if landfilled and is to be preferred. Markets for fused slag residues should be considered.8. Gypsum, produced by desulphurisation with lime or limestone, may be saleable, depending on the process and operating conditions. However, where the gypsum is contaminated, for example, with excess reagent, other additives or ash, this is unlikely.9. Leachate from coal stocks should be collected and treated.10. Whether recycling is possible will depend on site-specific factors such as the particular fuels, raw materials, products and methods of operation. For example, partially reacted lime may be recycled in the absorption of SO₂. The Operator should evaluate the opportunities for recycling.11. Ion exchange resins, reverse osmosis membranes, molecular sieves and catalysts should be regenerated and rinsed on-site, where practicable, to minimise the frequency of, and amounts for, disposal. The methods used should be compatible with good air and water pollution control. Where onsite regeneration or rinsing is not possible, they should be returned to the supplier or a third party for regeneration. Only when opportunities for rinsing and regeneration are not technically or economically practicable should disposal be considered.12. Sludges and solid waste arising from wet scrubbing of flue gases, water filtration and treatment, effluent treatment, spillage containment and from periodic cleaning of oil storage tanks, heaters and ancillary equipment, such as cooling towers, should be recycled and recovered wherever possible. Only when recovery is technically or economically impractical should they be directed to a suitably licensed waste disposal facility, where options may include one, or a combination, of the following, as justified by the operator:<ul style="list-style-type: none">– incineration– solidification– encapsulation– landfill

14. Solid wastes may be saleable (e.g. sulphur, gypsum, certain categories of ash), or acceptable at a licensed waste disposal site. Outlets should be sought and used by the operator wherever practicable, for the productive disposal of ash produced during running and maintenance, for example, in the construction or road building industries. The construction and use of conventional ash lagoons on new plant should be justified by the operator. Quenching into smaller tanks with scraper conveyors should be used for bottom ash.
15. Fly ash, etc collected in dry arrestment plant should be transferred to silo storage for transport off site in closed tankers or direct to any process using it as feedstock.
16. Ash and process residues should be stored until sufficient quantities are available for disposal to an appropriate facility where not subject to a PPC landfill permit.
17. There may be solid wastes which arise from water filtration and treatment. These should be directed to an appropriate facility.
18. Small quantities of material collected on filters or resulting from spillage should be collected and contained until reasonable quantities are available for disposal in the manner described above.
19. Most coal-fired power stations employ some form of on-site tipping, this may be subject to a PPC permit. The disposal of ash is either as a sludge in lagoons or as ash in landfills and on-site voids. Ash is generally regarded as non-hazardous and inert. However, consideration should be given to the possibility of leaching when siting ash dumps. The Regulator's responsibilities include on-site waste disposal to land.
20. On-site landfills may also contain a large amount of timber from cooling towers that have been treated with wood preservatives.
21. Spent catalyst from SCR plant should be returned to the manufacturer where possible.
22. Substances for disposal to land may include: various forms of ash and clinker; gypsum and partially reacted lime and limestone; low-value catalysts; and in the case of oil combustion, soots containing polyaromatic hydrocarbons, vanadium and nickel. Other substances may include building materials, scrap metal and wood, maintenance items, etc.
23. Wastes should be sampled and characterised, which may include a detailed analysis, at appropriate frequency, to ensure that they may be accepted at the waste disposal facility and so that the relevant information can be made available to the next holder as required by the Duty of Care Regulations.
- Markets for pulverised fuel ash should be explored.
 - Recovery of metals, e.g. vanadium and nickel, should be considered.

2.7 ENERGY

The requirement to address energy efficiency under the PPC Regulations will be satisfied provided the Operator meets the following conditions:

either

- the Operator meets the basic energy requirements in Section 2.7.1 and Section 2.7.2 below and is a participant to a Climate Change Agreement (CCA) or a Direct Participant Agreement (DPA) within the Emissions Trading Scheme.

or

- the Operator meets the basic energy requirements in Section 2.7.1 and Section 2.7.2 below and the further sector-specific energy requirements in Section 2.7.3 below.

Note that even where a Climate Change Agreement or Direct Participant Agreement is in place, this does not preclude the consideration of energy efficiency (including those

identified in Section 2.7.3) as part of an integrated assessment of BAT where they impact on other emissions, e.g. where:

- the choice of fuel impacts upon emissions other than carbon, e.g. sulphur in fuel
- the minimisation of waste by waste-to-energy does not maximise energy efficiency, e.g. by Combined Heat and Power (CHP)
- the most energy-intensive abatement leads to the greatest reduction in other emissions

Further guidance is given in the guidance note [H2 Energy efficiency for IPPC](#).

2.7.1 Basic energy requirements (1)

The requirements of this section are basic low-cost energy standards that apply whether or not a CCA or DPA is in force for the installation.

Indicative requirements for basic energy requirements (1): Breakdown of the energy consumption and generation by source and the associated environmental emissions
<p>1 The Operator should provide annually the energy consumption information, shown in the table below, in terms of delivered energy and also, in the case of electricity, converted to primary energy consumption. For the public electricity supply, a conversion factor of 2.6 should be used. Where applicable, the use of factors derived from on-site heat and/or power generation, or from direct (non-grid) suppliers should be used. In the latter cases, the Operator should provide details of such factors. Where energy is exported from the installation, the Operator should also provide this information. In the application this information should be submitted in the inventory in the H1 software tool and should also supplement this with energy flow information (such as “Sankey” diagrams or energy balances) showing how the energy is used throughout the process.</p> <p>2 The Operator should provide the following Specific Energy Consumption (SEC) information. Define and calculate the SEC of the activity (or activities) based on primary energy consumption for the products or raw material inputs that most closely match the main purpose or production capacity of the installation. Provide a comparison of SEC against any relevant benchmarks available for the sector. (See BREF and Energy Efficiency Guidance). See Table 2.1 below.</p> <p>3 The Operator should provide associated environmental emissions. This is dealt with in the Operator’s response to the emissions inventory using the H1 software tool.</p>

Table 2.1: Example breakdown of delivered and primary energy consumption

Energy source	Energy consumption		
	Delivered, MWh	Primary, MWh	% of total
Electricity*			
Gas			
Oil			
Other (Operator to specify)			

* specify source.

2.7.2 Basic energy requirements (2)

The requirements of this section are basic low-cost energy standards that apply whether or not a CCA or DPA is in force for the installation.

Indicative requirements for basic energy requirements (2):
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Measures for improvement of energy efficiency					
<p>1 Operating, maintenance and housekeeping measures should be in place in the following areas, where relevant and which have a significant impact on the efficient use of energy at the installation: (Indicative checklists of appropriate measures are provided in Appendix 2 of the guidance note H2 Energy efficiency for IPPC.)</p> <ul style="list-style-type: none"> • air conditioning, process refrigeration and cooling systems (leaks, seals, temperature control, evaporator/condenser maintenance) • operation of motors and drives • compressed gas systems (leaks, procedures for use) • condenser and cooling systems • feedwater heating systems • steam distribution and utilisation systems (turbines, leaks, traps, insulation) • heat recovery systems • space heating and hot-water systems • lubrication to avoid high-friction losses • boiler operation and maintenance, e.g. optimising excess air • gas turbine/engine operation • other maintenance relevant to the activities within the installation 					
<p>2 Basic low-cost physical techniques should be in place to avoid gross inefficiencies. These should include insulation, containment methods, (such as seals and self-closing doors), and avoidance of unnecessary discharge of heated water or air (e.g. by fitting simple control systems such as timers and sensors).</p>					
<p>3 Energy-efficient building services should be in place to deliver the requirements of the Building Services section of the guidance note H2 Energy efficiency for IPPC. For energy intensive industries these issues may be of minor impact and should not distract effort from the major energy issues, but they should nonetheless find a place in the programme, particularly where they constitute more than 5 percent of the total energy consumption.</p>					
<p>4 Energy management techniques should be in place, according to the requirements of Section 2.3 noting, in particular, the need for monitoring of energy flows and targeting of areas for reductions.</p>					
<p>5 An energy efficiency plan should be provided that:</p> <ul style="list-style-type: none"> • identifies all techniques relevant to the installation, including those listed above and in Section 2.7.3, that are applicable to the installation • estimates the CO₂ savings that would be achieved by each measure over its lifetime • and, in the case where the activities are NOT covered by a CCA or DPA; provides information on the equivalent annual costs of implementation of the technique, the costs per tonne of CO₂ saved and the priority for implementation. A procedure is given in the Energy Efficiency Guidance Note. 					
<p>6 An example format of the energy efficiency plan is shown in Table 2.2.</p>					

Table 2.2: Example format for energy efficiency plan

ALL APPLICANTS			ONLY APPLICANTS WITHOUT CCA		
Energy efficiency measure	CO ₂ savings (tonnes)		Equivalent Annual Cost (EAC) £k	EAC/CO ₂ saved £/tonne	Date for implementation
	Annual	Lifetime			

The Energy Efficiency Guidance Note provides an appraisal methodology. If Operators use other appraisal methodologies they should state the method in the Application, and

provide evidence that appropriate discount rates, asset life and expenditure (£/t) criteria have been employed.

The energy efficiency plan is required to ensure that the Operator has considered all relevant techniques. However, where a CCA or DPA is in place the Regulator will only enforce implementation of those measures in categories 1-3 above.

2.7.3 Further energy-efficiency requirements

Indicative requirements for further energy-efficiency requirements

The following techniques should be implemented where they are judged to be appropriate based on a cost/benefit appraisal according to the methodology provided in Appendix 4 of the Guidance Note [H2 Energy efficiency for IPPC](#).

Energy supply techniques

1. Operators should demonstrate that they have considered alternative, more efficient forms of generating electricity and heat. The following techniques should be considered where applicable:

- use of Combined Heat and Power (CHP)
- generation of energy from waste, including the combustion or other thermal conversion of on-site generated wastes. Co-incineration with other fuels and joint schemes with other local operators should also be considered.
- use of less polluting fuels, such as biomass and the feasibility of using other renewable energy sources

2. The Operator should provide justification that the proposed or current situation represents BAT, irrespective of whether or not a CCA or DPA is in place, where there are other BAT considerations involved, e.g.:

- the choice of fuel impacts upon emissions other than carbon dioxide, e.g. sulphur dioxide;
- the potential for practical energy recovery from waste conflicts with energy efficiency requirements.

3. For power generating cycles, the maximum theoretical (thermodynamic) efficiency is obtained by maximising the working temperature difference. This implies high combustion temperatures and minimising the temperature at which heat is rejected from the cycle.

Boilers and furnaces

4. The Operator should conduct regular checks to minimize leakage of air into units operating below atmospheric pressure.

5. Fuel should be combusted as completely as possible and the heat generated should be transferred efficiently to the working medium, usually water in the case of boilers.

6. Good design, operation and maintenance of burners is required.

7. In addition to efficient boiler heat transfer design, further efficiency improvements may be obtained by optimal heat recovery through combustion air preheating and feedwater heating. Practical limits are reached by the tendency for increased NO_x formation with high air preheating and by the risk of condensation and corrosion by overcooled stack gases.

8. There should be evidence that the above factors have been taken into account in the design.

Steam turbines

9. The replacement of existing turbines by more efficient turbines may be justified.

10. Cycle efficiency may be increased by measures such as reheating steam between stages and improving the vacuum on condensers. The use of very high, including supercritical,

pressures increases the working temperature difference and increases cycle efficiency .Such factors should be considered in any application or relevant review.

11. Steam may also be taken between stages or from a back-pressure exhaust for use in, for example, process or building heating. Such use of combined heat and power (CHP) can radically improve the overall thermal efficiency of the installation and is favoured in all applications and relevant reviews.

Gas turbines

12. Thermal efficiency can vary widely between types and models. Some lose efficiency substantially when part loaded and, in large installations, it may be preferable to install more than one smaller turbine to allow efficient load following.

13. The thermal efficiency of a gas turbine is improved by increasing the combustion temperature, but this is limited by the materials of construction, and large amounts of excess air are needed to moderate temperatures.

14. Higher combustion temperatures tend to generate more NO_x and to make low NO_x combustion design more difficult.

15. Improved efficiency can be achieved by using concentric shafts to connect different stages of compression and expansion - this is common in aero derivative machines.

16. Further efficiency can be gained by intercooling between stages of air compression and reheating between stages of expansion. Such features are normally incorporated at the design stage and may not be relevant to retrofits.

17. The exhaust from even the most efficient gas turbines contains large amounts of heat that should be recovered, and used for process or building heating (CHP), or steam may be fed to a steam turbine to provide additional power in a combined cycle (CCGT) Supplementary fuel may also be fired in the heat recovery boiler to meet the heat demands. The design of the system needs to optimize the characteristics of the turbines and boiler to achieve the best overall performance.

Reciprocating engines

18. Engine efficiency can be improved by measures such as turbocharging and air intercooling and consideration should be given to these techniques to maximize efficiency. However, some sacrifice of efficiency may have to be made to help moderate emissions of NO_x.

19. The exhaust contains substantial heat at a temperature that permits its recovery for process or building heating or absorption chilling.

20. Lower-grade heat may be recovered from engine coolants.

21. Where additional heat is required, supplementary fuel may be fired into the boiler, although this can be complicated by the pulsating exhaust and size limitations.

These features are usually incorporated at the design stage. The Operator should justify any proposal that does not include combined heat and power.

2.8 ACCIDENTS

This section covers accidents and their consequences. It is not limited to major accidents but includes spills and abnormal operation.

Some installations will also be subject to the Control of Major Accident Hazards Regulations 1999 (COMAH) (see [Appendix 2](#) for equivalent legislation in Scotland and Northern

Ireland). IPPC and COMAH can sometimes overlap, and some systems and information may be usable for either regime.

The COMAH regime applies to major hazards, and for accident scenarios covered by COMAH, Operators may refer in the Application to any COMAH reports already held by the Regulator. However, the accident provisions under IPPC also cover those which are below the classification threshold for major accidents under COMAH, so Operators need to consider smaller accidents and abnormal operation scenarios as well. Guidance prepared in support of the COMAH Regulations (see the *COMAH guides*), may also help IPPC Operators in considering ways to reduce the risks and consequences of accidents - whether or not they are covered by the COMAH regime.

General management requirements are covered in *Section 2.3*. For accident management, there are three particular components:

- identification of the hazards posed by the installation/activity
- assessment of the risks (hazard x probability) of accidents and their possible consequences
- implementation of measures to reduce the risks of accidents, and contingency plans for any accidents that do occur

Indicative requirements for accidents and abnormal operations

1 A formal structured accident management plan should be in place which covers the following aspects:

A - Identification of the hazards to the environment posed by the installation using a methodology akin to a Hazop study. Areas to consider should include, but should not be limited to, the following:

- transfer of substances (e.g. filling or emptying of vessels);
- overfilling of vessels;
- emissions from plant or equipment (e.g.. leakage from joints, over-pressurisation of vessels, blocked drains);
- failure of containment (e.g. physical failure or overfilling of bunds or drainage sumps);
- failure to contain firewaters;
- wrong connections made in drains or other systems;
- incompatible substances allowed to come into contact;
- unexpected reactions or runaway reactions;
- release of an effluent before adequate checking of its composition;
- failure of main services (e.g. power, steam, cooling water);
- operator error;
- vandalism.

B - Assessment of the risks. The hazards having been identified, the process of assessing

the risks should address six basic questions:

- how likely is the particular event to occur (source frequency)?
- what substances are released and how much of each (risk evaluation of the event)?
- where do the released substances end up (emission prediction - what are the pathways and receptors)?
- what are the consequences (consequence assessment – what are the effects on the receptors)?
- what are the overall risks (determination of overall risk and its significance to the environment)?
- what can prevent or reduce the risk (risk management – measures to prevent accidents and/or reduce their environmental consequences)?

The depth and type of assessment will depend on the characteristics of the installation and its Location. The main factors to take into account are:

- the scale and nature of the accident hazard presented by the installation and the activities
- the risks to areas of population and the environment (receptors)
- the nature of the installation and complexity of the activities and the relative difficulty in

deciding and justifying the adequacy of the risk-control techniques

C - identification of the techniques necessary to reduce the risks. The following techniques are relevant to most installations:

- there should be an up-to-date inventory of substances, present or likely to be present, which could have environmental consequences if they escape. This should include apparently innocuous substances that can be environmentally damaging if they escape (for example, a tanker of milk spilled into a watercourse can destroy its ecosystem). The Permit will require the Regulator to be notified of any significant changes to the inventory.
- procedures should be in place for checking and handling raw materials and wastes to ensure compatibility with other substances with which they may accidentally come into contact.
- storage arrangements for raw materials, products and wastes should be designed and operated to minimise risks to the environment.
- there should be automatic process controls backed-up by manual supervision, both to minimise the frequency of emergency situations and to maintain control during emergency situations. Instrumentation will include, where appropriate, microprocessor control, trips and process interlocks, coupled with independent level, temperature, flow and pressure metering and high or low alarms.
- physical protection should be in place where appropriate (e.g.. barriers to prevent damage to equipment from the movement of vehicles).
- there should be appropriate secondary containment (e.g. bunds, catchpots, building containment).
- techniques and procedures should be in place to prevent overfilling of tanks - liquid or powder (e.g. level measurement displayed both locally and at the central control point, independent high-level alarms, high-level cut-off, and batch metering).
- where the installation is situated in a floodplain, consideration should be given to techniques which will minimise the risk of the flooding causing a pollution incident or making one worse.
- security systems to prevent unauthorised access should be provided where appropriate.
- there should be formal systems for the logging and recording of all incidents, near-misses, abnormal events, changes to procedures and significant findings of maintenance inspections.
- there should be procedures for responding to and learning from incidents, near-misses, etc.
- the roles and responsibilities of personnel involved in incident management should be formally specified.
- clear guidance should be available on how each accident scenario might best be managed (eg. containment or dispersion, to extinguish fires or to let them burn).
- procedures should be in place to avoid incidents occurring as a result of poor communications between staff at shift change or during maintenance or other engineering work.
- safe shutdown procedures should be in place.
- communication channels with emergency services and other relevant authorities should be established, and available for use in the event of an incident. Procedures should include the assessment of harm following an incident and the steps needed to redress this
- appropriate control techniques should be in place to limit the consequences of an accident, such as isolation of drains, provision of oil spillage equipment, alerting of relevant authorities and evacuation procedures.
- personnel training requirements should be identified and training provided.
- the systems for the prevention of fugitive emissions are generally relevant ([Section 2.2.8](#) and [Section 2.2.9](#)) and in addition, for drainage systems:
 - procedures should be in place to ensure that the composition of the contents of a bund sump, or sump connected to a drainage system, are checked before treatment or disposal;
 - drainage sumps should be equipped with a high-level alarm or with a sensor and automatic pump to storage (not to discharge);
 - there should be a system in place to ensure that sump levels are kept to a minimum at all times;
 - high-level alarms and similar back-up instruments should not be used as the primary method of level control:
 - duplicate or standby plant should be provided where necessary, with maintenance and testing to the same standards as the main plant;

- spill contingency procedures should be in place to minimise accidental release of raw materials, products and waste materials and then to prevent their entry into water;
- process waters, potentially contaminated site drainage waters, emergency firewater, chemically-contaminated waters and spillages of chemicals should be contained and, where necessary, routed to the effluent system and treated before emission to controlled waters or sewer. Sufficient storage should be provided to ensure that this can be achieved. Any emergency firewater collection system should take account of the additional firewater flows and fire-fighting foams, and emergency storage lagoons may be needed to prevent contaminated firewater reaching controlled waters (see the [Releases to water references](#)).
- consideration should be given to the possibility of containment or abatement of accidental emissions from vents and safety relief valves/bursting discs. Where this may be inadvisable on safety grounds, attention should be focused on reducing the probability of the emission.

2.9 NOISE

Within this section “noise” should be taken to refer to “noise and/or vibration” as appropriate, detectable beyond the site boundary.

Where noise issues are likely to be relevant, the Operator will be required, in the Application, to provide information on the following: (for more details see [H3 Part 1 Noise](#))

- the main sources of noise and vibration that will fall within the IPPC installation and also on Infrequent sources of noise and vibration
- the nearest noise-sensitive sites
- conditions/limits imposed under other regimes
- the local noise environment
- any environmental noise measurement surveys, modelling or any other noise measurements any specific local issues and proposals for improvements.

The level of detail supplied should be in keeping with the risk of causing noise-related annoyance at sensitive receptors.

Where an installation poses no risk of noise-related environmental impact because the activities undertaken are inherently quiet, this should be justified and no further information relating to noise need normally be supplied. It should, however, be remembered that there can still be an underlying level of annoyance without complaints being made.

The PPC Regulations require installations to be operated in such a way that “all the appropriate preventative measures are taken against pollution, in particular through the application of BAT”. The definition of pollution includes “emissions that may be harmful to human health or the quality of the environment, cause offence to human senses or impair or interfere with amenities and other legitimate uses of the environment”. BAT is therefore likely to be similar, in practice, to the requirements of the statutory nuisance legislation, which requires the use of “best practicable means” to prevent or minimise noise nuisance.

In the case of noise, “offence to any human senses” can normally be judged by the likelihood of complaints, but in some cases it may be possible to reduce noise emissions still further at reasonable costs, and this may exceptionally therefore be BAT for noise emissions.

For advice on how noise and/or vibration related limits and conditions will be determined see [H3 Part 1 Noise](#)

Indicative BAT requirements for noise and vibration

Identification of the main sources of noise and vibration (including infrequent sources), the nearest noise-sensitive locations and relevant environmental surveys which have been undertaken, and the techniques and measures used for the control of noise.

1 The Operator should employ basic good practice measures for the control of noise, including adequate maintenance of any parts of plant or equipment whose deterioration may give rise to increases in noise (for example, maintenance of bearings, air handling plant, the building fabric as well as specific noise attenuation measures associated with plant, equipment or machinery).

2 The Operator should also employ such other noise control techniques to ensure that the noise from the installation does not give rise to reasonable cause for annoyance, in the view of the Regulator and, in particular, should justify where either Rating Levels ($LA_{eq,T}$) from the installation exceed the numerical value of the Background Sound Level ($LA_{90,T}$).

3 Further justification will be required should the resulting field rating level ($L_{AR,TR}$) exceed 50 dB by day and a facade rating level exceed 45 dB by night, with day being defined as 07:00 to 23:00 and night 23:00 to 07:00.

4 In some circumstances "creeping background" may be an issue. Where this has been identified in pre application discussions or in previous discussions with the local authority, the Operator should employ such noise control techniques as are considered appropriate to minimise problems to an acceptable level within the BAT criteria.

Noise surveys, measurement, investigation (which can involve detailed assessment of sound power levels for individual items of plant) or modelling may be necessary for either new or existing installations depending upon the potential for noise problems. Operators may have a noise management plan as part of their management system.

2.10 MONITORING

This section describes monitoring and reporting requirements for emissions to all environmental media. Guidance is provided for selecting the appropriate monitoring methodologies, frequency of monitoring, compliance-assessment criteria and environmental monitoring.

2.10.1 Emissions monitoring

Indicative requirements for emissions monitoring (Sheet 1 of 2)

Describe the proposed measures for monitoring emissions, including any environmental monitoring, and the frequency, measurement methodology and evaluation procedure proposed.

1 Monitoring should generally be undertaken during all phases of operation (i.e. commissioning, start-up, normal operation and shutting-down) unless the Regulator agrees that it is inappropriate.

2 Continuous monitoring (or at least sampling in the case of water) and recording are likely to be required under the following circumstances:

- Where the potential environmental impact is significant or the concentration of substance varies widely.
- Where a substance is abated continuous monitoring of the substance is required to show the performance of the abatement plant. For example continuous monitoring of dust is needed after a fabric filter to show the effectiveness of the filter and indicate when maintenance is needed, or sampling BOD from an effluent treatment plant.
- Where other control measures are required to achieve satisfactory levels of emission (e.g. material selection).

3 Where effective surrogates are available, they may be used to minimise monitoring costs.

4 Where monitoring shows that substances are not emitted in significant quantities, it may

be possible to reduce monitoring frequency.

5 For analysis techniques and compliance criteria see [Appendix 1](#).

Monitoring and reporting of emissions to air

6 Where appropriate, periodic visual and olfactory assessment of releases should be undertaken to ensure that all final releases to air should be essentially colourless, free from persistent trailing mist or fume and free from droplets.

7 Many plants in this sector will be subject to the detailed monitoring requirements of Annex VIII of the Large Combustion Plant Directive (LCPD). For plants co-incinerating waste, the provisions of Articles 10, 11 and Annexes II and III of the Waste Incineration Directive (WID) should also apply.

The LCPD requires that for existing plant using continuous emission monitors the emission limit values shall be regarded as having been complied with if the evaluation of the results indicates, for operating hours within a calendar year, that:

(a) none of the calendar monthly mean values exceeds the emission limit values; and

(b) in the case of:

- (i) sulphur dioxide and dust: 97 % of all the 48 hourly mean values do not exceed 110 % of the emission limit values,
- (ii) nitrogen oxides: 95 % of all the 48 hourly mean values do not exceed 110 % of the emission limit values.

Start-up and shut-down periods shall be disregarded.

For new plants emission limit values shall be regarded, for operating hours within a calendar year, as complied with if:

- (a) no validated daily average value exceeds the relevant figures set out in part B of Annexes III to VII, and
- (b) 95 % of all the validated hourly average values over the year do not exceed 200 % of the relevant figures set out in part B of Annexes III to VII.

For both existing and new plants, start-up and shut-down periods shall be disregarded.

The monitoring requirements of the LCPD and WID are considered to represent BAT for this sector and should be referred to in respect of their detailed requirements.

Installations that do not fall within the scope of the WID or LCPD should meet the standards expected of plants except where the Operator can clearly demonstrate that this is not BAT.

The Regulator may require an Operator to monitor and report releases more frequently than required by the WID or LCPD where it is considered BAT to do so.

The readouts from continuous emission monitors should be processed using software that reports monitoring compliance information to enable direct comparison with the emission limit values specified in relevant European legislation and in this guidance (**see Section 3**).

In order to relate emission concentrations to mass releases, it will be necessary to measure or otherwise determine the stack gas flow rate. In order to relate measurements to reference conditions, temperature and pressure will need to be determined. Determination of oxygen or water vapour content may also be required. All such measurements should be recorded.

The Environment Agency has established its Monitoring Certification Scheme (MCERTS) to deliver quality environmental measurements. MCERTS provides for the product certification of monitoring systems (for example, instruments, analysers and equipment), the competency certification of personnel and the accreditation of laboratories under the requirements of European and international standards. MCERTS brings together relevant standards into a scheme that can be easily accessed by key stakeholders, such as manufacturers, operators, regulators and test houses. Eventually, MCERTS will be extended to include all regulatory monitoring activities. TGNs M1 and M2 are key reference documents underpinning MCERTS for stack-emission monitoring.

Quality Assurance of automated emissions monitoring devices is also addressed by EN14181 (2004), which specifies three Quality Assurance levels covering:

- The fitness for purpose of an instrument for the process as determined from its performance characteristics
- In-situ 'calibration' of the instruments by means of parallel measurements carried out by a UKAS accredited test laboratory using standard reference methods based on manual sampling. The operator is required to perform a weekly check that measured data fall within the valid calibration range.
- Ongoing performance checks based on regular zero and span drift assessments and an Annual Surveillance Test that requires the laboratory to make additional parallel measurements in order to verify the validity of 'calibration'.

The provisions of EN 14181 are wide ranging and must be adopted under the scope of the LCPD and WID, which also define availability targets for emissions monitoring equipment.

Monitoring and reporting of emissions to water and sewer

8 For combustion plants co-incinerating waste and operating air pollution control equipment with an aqueous discharge, Operators should comply with Article 8 and Annexes III and IV of the Waste Incineration Directive² (WID).

9 The Operator should also have a fuller analysis carried out covering a broad spectrum of substances to establish that all relevant substances have been taken into account when setting the release limits. This should cover the substances listed in Schedule 5 of the Regulations unless it is agreed with the Regulator that they are not applicable. The need to repeat such a test will depend upon the potential variability in the process and, for example, the potential for contamination of raw materials. Where there is such potential, tests may be appropriate.

10 Any substances found to be of concern, or any other individual substances to which the local environment may be susceptible and upon which the operations may impact, should also be monitored more regularly. This would particularly apply to the common pesticides and heavy metals. Using composite samples is the technique most likely to be appropriate where the concentration does not vary excessively.

11 In some sectors there may be releases of substances that are more difficult to measure and whose capacity for harm is uncertain, particularly when combined with other substances. "Whole effluent toxicity" monitoring techniques can therefore be appropriate to provide direct measurements of harm, for example, direct toxicity assessment. See [Section 2.2.6](#). However, due to the nature of effluent arising in this sector, DTA is unlikely to be applicable.

Monitoring and reporting of waste emissions

12 For waste emissions, the following should be monitored and recorded:

- the physical and chemical composition of the waste
- its hazard characteristics

² Directive 2000/76/EC of the European Parliament and of the Council of 4 December 2000 on the incineration of waste. Official Journal of the European Communities 28.12.2000 L332/91.

- handling precautions and substances with which it cannot be mixed

2.10.2 Environmental monitoring (beyond installation)

Specific environmental monitoring requirements which may be appropriate for this sector:

To water:

- effluent treatment plant discharges to controlled waters
- cooling water discharges

To air:

Where there is a significant public concern/record of complaint:

- 24 hour time/date coded CCTV/video recordings of chimney stack emissions should be kept for those sites
- plants should record wind speed and direction data to assist with complaint investigation.

To land:

Monitoring surveys may need to be established where sensitive soil systems or terrestrial ecosystems are at risk from deposition of air borne pollutants or direct impacts of any on site waste storage and treatment operations.

Indicative requirements for environmental monitoring (beyond installation)

Describe the proposed measures for monitoring emissions, including any environmental monitoring, and the frequency, measurement methodology and evaluation procedure proposed.

1 The Operator should consider the need for environmental monitoring to assess the effects of emissions to controlled water, groundwater, air or land, or emissions of noise or odour.

2 Environmental monitoring may be required, for example, when:

- there are vulnerable receptors
- the emissions are a significant contributor to an Environmental Quality Standard (EQS) that may be at risk
- the Operator is looking for departures from standards based on lack of effect on the environment;
- to validate modelling work
- to inform operating conditions through direct linking of ambient monitoring station real time outputs to the plant control room e.g. to inform the choice of fuel/switching to low sulphur fuels when weather conditions and monitoring indicates that an EQS may be at risk

3 The need should be considered for:

- groundwater, where it should be designed to characterise both quality and flow and take into account short- and long-term variations in both. Monitoring will need to take place both up-gradient and down-gradient of the site
- surface water, where consideration will be needed for sampling, analysis and reporting for upstream and downstream quality of the controlled water
- air, including odour
- land contamination, including vegetation, and agricultural products
- assessment of health impacts
- noise

4 Where environmental monitoring is needed, the following should be considered in

drawing up proposals:

- determinands to be monitored, standard reference methods, sampling protocols
- monitoring strategy, selection of monitoring points, optimisation of monitoring approach
- determination of background levels contributed by other sources
- uncertainty for the employed methodologies and the resultant overall uncertainty of measurement
- quality assurance (QA) and quality control (QC) protocols, equipment calibration and maintenance, sample storage and chain of custody/audit trail
- reporting procedures, data storage, interpretation and review of results, reporting format for the provision of information for the Regulation

5 Guidance on air quality monitoring strategies and methodologies can be found in [Monitoring Guidance](#).

2.10.3 Monitoring of process variables

Indicative requirements for monitoring of process variables

Describe the proposed measures for monitoring emissions, including any environmental monitoring, and the frequency, measurement methodology and evaluation procedure proposed.

1 The operator should cross reference installation-specific operational procedures to ensure that emissions monitoring is robust, this may include some process variables which may affect the environment. Examples might be:

- for solid and liquid fuel fired plants, fuel feedstock should be sampled and analysed at a frequency and manner appropriate to the type of plant concerned.
- Differential pressure across abatement equipment which can indicate removal efficiency, filter failures, etc..
- Potential difference across EP plates
- Reagent injection or feed rates
- Oxygen content of flue gas

2.10.4 Monitoring standards (Standard Reference Methods)

The Environment Agency has introduced its Monitoring Certification Scheme (MCERTS) to improve the quality of monitoring data and to ensure that the instrumentation and methodologies employed for monitoring are fit for purpose. Performance standards have been published for continuous emissions monitoring systems (CEMs), ambient air quality monitoring systems (CAMs), chemical testing of soils, water monitoring instrumentation and manual stack emissions monitoring. Other MCERTS standards are under development to cover portable emissions monitoring equipment, data acquisition and Operators' own arrangements, such as installation, calibration and maintenance of monitoring equipment, position of sampling ports and provision of safe access for manual stack monitoring.

The following should be described in the application, indicating which monitoring provisions comply with MCERTS requirements or where other arrangements have been made:

- monitoring methods and procedures (selection of Standard Reference Methods)
- justification for continuous monitoring or spot sampling
- reference conditions and averaging periods
- measurement uncertainty of the proposed methods and the resultant overall uncertainty criteria for the assessment of non-compliance with Permit limits and
- details of monitoring strategy aimed at demonstration of compliance
- reporting procedures and data storage of monitoring results,
- record keeping and reporting intervals for the provision of information to the Regulator
- procedures for monitoring during start-up and shut-down and abnormal process conditions
- drift correction calibration intervals and methods
- the accreditation held by samplers and laboratories or details of the people used and the training/competencies

Indicative requirements for monitoring standards (Standard Reference Methods)

Describe the proposed measures for monitoring emissions, including any environmental monitoring, and the frequency, measurement methodology and evaluation procedure proposed.

1 As far as possible, Operators should ensure their monitoring arrangements comply with the requirements of MCERTS where available, for example using certified instruments and equipment, and using a stack testing organisation accredited to MCERTS standards. Where the monitoring arrangements are not in accordance with MCERTS requirements, the Operator should provide justification and describe the monitoring provisions in detail. See [MCERTS approved equipment](#) for future information on MCERTS and a listing of MCERTS equipment.

Sampling and analysis standards

2 The analytical methods given in [Appendix 1](#) should be used. If other substances need to be monitored the standard should be selected in the order of priority as given in the IPPC Bureau's Reference Document on the General Principles of Monitoring. This order is:

- Comitee Europeen de Normalisation (CEN)
- International Standardisation Organisation (ISO)

If the substance cannot be monitored using CEN or ISO standards then a method can be Selected from any one of the following

- American Society for Testing and Materials (ASTM)
- Association Française de Normalisation (AFNOR)
- British Standards Institution (BSI)
- Deutsches Institute fur Normung (DIN)
- United States Environmental Protection Agency (US EPA)
- Verein Deustcher Ingenieure (VDI)

If the substance cannot be monitored using any of the standards above then other methods may be adapted for use, following the requirements for validation in ISO 17025. For stack emission monitoring the following occupational methods may be adapted:

- Methods for the Determination of Hazardous Substances (MHDS) series published by the

Health and Safety Executive (HSE)

- National Institute for Occupational Safety and Health (NIOSH)
- Occupational Safety and Health Administration (OSHA)

The intended application of the standard method must always be taken into account. For example, a CEN method may be less suitable than another less-rigorously validated standard method if the application is not one for which the CEN method was developed.

Operators should be expected to be able to demonstrate compliance with the above hierarchy and validate use of non-standard methods, in-house designed/developed methods, standard methods used outside their intended scope and modifications of standard methods to confirm that these methods are fit for purpose. These procedures will be formalised under forthcoming European standards.

3 Further guidance on standards for monitoring gaseous releases relevant to IPC/IPPC is given in the [Monitoring Guidance](#). A series of updated Guidance Notes covering this subject is being prepared. This guidance specifies manual methods of sampling and analysis that will also be suitable for calibration of continuous emission monitoring instruments. Further guidance relevant to water and waste is available from the publications of the Standing Committee of Analysts.

If in doubt the Operator should consult the Regulator.

2.11 CLOSURE

The PPC Regulations require an Applicant to submit a site report, describing the condition of the site, as part of the application. **Guidance on this is in [H7 Application Site Report and Site Protection and Monitoring Programme or Guidance for SEPA Staff On Land and Groundwater Considerations for PPC Part A Installations \(Scotland\)](#) (see [PPC Part A Installations: Guide for Applicants \(Scotland\)](#))**. Please note that the Environment Agency has recently consulted on H8 on the Protection of Land under the PPC Regime: Surrender Site Report and Template

Indicative requirements for closure (Sheet 1 of 2)

Describe the proposed measures, upon definitive cessation of activities, to avoid any pollution risk and return the site of operation to a satisfactory state (including where appropriate, measures relating to the design and construction of the installation).

1 Operations during the IPPC Permit

Operations during the life of the IPPC Permit should not lead to any deterioration of the site if the requirements of the other sections of this and the specific-sector notes are adhered to. Should any instances arise which have, or might have, impacted on the state of the site, the Operator should record them along with any further investigation or ameliorating work carried out. This will ensure that there is a coherent record of the state of the site throughout the period of the IPPC Permit. This is as important for the protection of the Operator as it is for the protection of the environment. Any changes to this record should be submitted to the Regulator.

2 Steps to be taken at the design-and-build stage of the activities

Care should be taken at the design stage to minimise risks during decommissioning. For existing installations, where potential problems are identified, a programme of improvements should be put in place to a timescale agreed with the Regulator. Designs should ensure that:

- underground tanks and pipework are avoided where possible (unless protected by secondary containment or a suitable monitoring programme)
- there is provision for the draining and clean-out of vessels and pipework prior to dismantling
- lagoons and landfills are designed with a view to their eventual clean-up or surrender
- insulation is provided that is readily dismantled without dust or hazard

- materials used are recyclable (having regard for operational or other environmental objectives)

3 The site-closure plan

A site closure plan should be maintained to demonstrate that, in its current state, the installation can be decommissioned to avoid any pollution risk and return the site of operation to a satisfactory state. The plan should be kept updated as material changes occur. Common sense should be used in the level of detail, since the circumstances at closure will affect the final plans. However, even at an early stage, the closure plan should include:

- either the removal or the flushing out of pipelines and vessels where appropriate and their complete emptying of any potentially harmful contents
- plans of all underground pipes and vessels
- the method and resource necessary for the clearing of lagoons
- the method of ensuring that any on-site landfills can meet the equivalent of surrender conditions
- the removal of asbestos or other potentially harmful materials unless agreed that it is reasonable to leave such liabilities to future owners
- methods of dismantling buildings and other structures, see [Closure references](#) which gives guidance on the protection of surface and groundwater at construction and demolition-sites testing of the soil to ascertain the degree of any pollution caused by the activities and the need for any remediation to return the site to a satisfactory state as defined by the initial site report

4 For existing activities, the Operator should complete any detailed studies, and submit the site closure plan as an improvement condition to a timescale to be agreed with the Regulator but in any case within the timescale given in [Section 1.1](#) (Note that radioactive sources are not covered by this legislation, but decommissioning plans should be co-ordinated with responsibilities under the Radioactive Substances Act 1993.)

2.12 INSTALLATION ISSUES

In some cases it is possible that actions that benefit the environmental performance of the overall installation will increase the emissions from one Permit-holder's activities. For example, taking treated effluent as a raw water supply will probably slightly increase emissions from that activity, but could dramatically cut the total emissions from the whole installation.

Where the Applicant is not the only Operator of the installation, they should describe the proposed techniques and measures (including those to be taken jointly by themselves and other Operators) for ensuring the satisfactory operation of the whole installation

Indicative BAT requirements for installation wide issues

Where you are not the only Operator of the installation, describe the proposed techniques and measures (including those to be taken by yourself and other Operators) for ensuring the satisfactory operation of the whole installation.

1 The Operator should consider possibilities for minimising environmental impact to the environment as a whole, by operating together with other Permit holders. Possibilities include:

- Communication procedures between the various Permit-holders; in particular those needed to ensure that the risk of environmental incidents is minimised.
- Benefiting from the economies of scale to justify the installation of a CHP plant.
- The combining of combustible wastes to justify a combined waste-to-energy/CHP plant.
- The waste from one activity being a possible feedstock for another.
- The treated effluent from one activity being of adequate quality to be the raw water feed for another activity.
- The combining of effluent to justify a combined or upgraded effluent-treatment plant.
- The avoidance of accidents from one activity that may have a detrimental knock-on effect on the neighbouring activity.
- Land contamination from one activity affecting another – or the possibility that one

Operator owns the land on which the other is situated.

3 Emissions

3.1 EMISSIONS INVENTORY

The Regulations require the Applicant to describe the nature, quantities and sources of foreseeable emissions into each medium. This may be done by completing the inventory of emission and consumption in the [H1 software tool](#). The information required is as follows.

Provide a table of significant emissions of substances (except noise, vibration, odour and heat which are covered in their respective sections) that will result from the proposals and should include, preferably in order of significance:

- substance (where the substance is a mixture, for example, VOCs or COD, separate identification of the main constituents or inclusion of an improvement proposal to identify them)
- source, including height, location and efflux velocity
- media to which it is released
- any relevant EQS or other obligations
- benchmark
- proposed emissions normal/max expressed, as appropriate for:
 - mass/unit time
 - concentration
 - annual mass emissions
- statistical basis (average, percentile etc.)
- notes covering the Operator's confidence in his ability to meet the benchmark values
- if intermittent, the appropriate frequencies
- plant loads at which the data is applicable
- whether measured or calculated (the method of calculation should be provided)

The response should clearly state whether the emissions are current emission rates or those planned following improvements, and should cover emissions under both normal and abnormal conditions for:

- point-source emissions to surface water, groundwater and sewer
- waste emissions
- point-source emissions to air
- significant fugitive emissions to all media, identifying the proportion of each substance released that is due to fugitives rather than point-source releases
- abnormal emissions from emergency relief vents, flares and the like
- indirect and direct emission of carbon dioxide associated with energy consumed or generated

Emissions of carbon dioxide associated with energy use should be broken down by energy type and, in the case of electricity, by source, for example, public supply, direct supply or on-site generation. Where energy is generated on-site, or from a direct (non-public) supplier, the Operator should specify and use the appropriate factor. Standard factors for carbon dioxide emissions are provided in the guidance note [H2 Energy efficiency for IPPC](#).

Where VOCs are released, the main chemical constituents of the emissions should be identified.

For waste, emissions relate to any wastes removed from the installation, or disposed of at the installation under the conditions of the Permit, for example, landfill. Each waste should have its composition determined and the amounts expressed in terms of cubic metres or tonnes per month. A suitable table on which to record this information is provided in the electronic version of this Guidance Note.

Indicative BAT requirements for emission benchmarks

Describe the nature, quantities and sources of foreseeable emissions into each medium (which will result from the techniques proposed in Section 2).

- 1 The Operator should compare the emissions with the benchmark values given in the remainder of this Section.
- 2 Where the benchmarks are not met, the Operator should revisit the responses made in Section 2 as appropriate and make proposals for improvements or justify not doing so as part of the BAT assessment.

3.2 EMISSION BENCHMARKS

Guidance is given below on release concentrations or mass release rates achievable for key substances using the best combination of techniques. These BAT-based benchmarks are not mandatory release limits and reference should be made to Section 1 and the Guide for Applicants regarding their use.

3.2.1 Emissions to air associated with BAT

The emissions quoted below are daily averages based upon continuous monitoring during the period of operation. See [Section 3.2.6](#) for the standard conditions that should be applied. Care should always be taken to convert benchmark and proposed releases to the same reference conditions for comparison. To convert measured values to reference conditions, see the [Monitoring Guidance](#) for more information. The benchmarks given do not take sampling, analytical errors, or uncertainties into account. This needs to be considered when setting an ELV for a Permit.

Limits in Permits may be set for mean or median values over long or short periods. The periods and limits selected should reflect:

- the manner in which the emission may impact upon the environment
- likely variations which will arise during operation within BAT
- possible failure modes and their consequences
- the capabilities of the monitoring and testing system employed

Where emissions are expressed in terms of concentrations and where continuous monitors are employed, it is recommended that limits are defined such that:

New plants

- No daily average value exceeds the benchmark value
- 95% of all hourly averages over a defined period, eg a calendar year do not exceed 200% of the benchmark value

Retrofit plant

- No monthly average value (where defined in table 3.1) exceeds the benchmark value
- For SO₂ and dust 97% of the 48 hour average values do not exceed 110% of the benchmark value
- For NO_x 95% of the 48 hour average values do not exceed 110% of the benchmark value

Where spot tests are employed:

- it may be necessary to set periodic limits taking account of sampling times practical for the spot test method involved
- and continuous and spot test sampling periods are compatible, the mean of three consecutive tests taken during a calendar year shall not exceed the relevant continuous monitoring benchmark value by more than 10%

Note that processes which come under the provisions of the Large Combustion Plant Directive or the Waste Incineration Directive will also need to address the specific requirements of these directives.

Table 3.1 - Summary of achievable releases to air (normal font - daily averages, underline font - monthly average see S3.2.1)

Note ¹ where FGD used

Note ² LS coal will produce typically 100mgm⁻³ per 0.1% Cl in coal. DSI will reduce this by up to 90%

Note ³ Where straw or other higher Cl containing biomass material are used, HCl concentrations may be up to 300mgm⁻³

Note ⁴ Upper end of range applies where higher moisture content biomass is BAT.

Fuels and processes	Size	Process	Ref % O ₂	Achievable concentrations, mgm ⁻³ , dry at 0°C, 101.3 kPa (at ref O ₂)					
				PM	SO ₂	NO _x	N ₂ O	CO	HCl
Coal	50-100 MW _{th}	New Grates/PC	6	20	400	300	10	150	10 ^{1&2}
		New CFBC and PFBC		20	400	300	30-120	150	30
		New BFBC		20	400	300	30-120	100	5
		Retrofit PC	6	100	1300	<u>600</u>	2-10	400	400 ²
		Retrofit CFBC and PFBC		100	1300	<u>600</u>	30-120	150	30
		Retrofit BFBC		100	1300	<u>600</u>	30-120	100	1-5
	100-300 MW _{th}	New PC	6	20	200	200	2-10	150	10 ^{1&2}
		New CFBC and PFBC		20	200	200	30-120	150	30
		New BFBC		20	200	200	30-120	100	1-5
		Retrofit PC		<u>100</u>	<u>400</u>	<u>600</u>	2-10	400	400 ²
		Retrofit CFBC and PFBC		<u>100</u>	<u>400</u>	<u>600</u>	30-120	100	30
		Retrofit BFBC		<u>100</u>	<u>400</u>	<u>600</u>	30-120	100	1-5
	>300 MW _{th}	New PC	6	10	150	150	2-10	150	10
		New CFBC and PFBC		10	200	200	30-120	150	30
		New BFBC		10	200	150	30-120	100	1-5
		Retrofit PC with FGD & OFA	6	<u>25</u>	<u>400</u>	<u>500</u>	2-10	400	0 ¹
		... with OFA		<u>50</u>	<u>2,000</u>	<u>500</u>	2-10	400	400 ²
		Retrofit CFBC and PFBC		<u>100-50</u>	<u>100-200</u>	<u>500</u>	30-120	100	30
		Retrofit BFBC		<u>100-50</u>	<u>1200-400</u>	<u>500</u>	30-120	100	1-5
	>500 MW _{th}	Retrofit PC with FGD & OFA	6	<u>25</u>	<u>400</u>	<u>500</u>		400	40 ¹
		...with OFA		<u>50</u>	<u>2000</u>	<u>500</u>		400	400 ²
Biomass	50-100	New PF/Grates	6	20	300	300		100-250 ⁴	25 ³
		New FBC				250		100-150 ⁴	

Fuels and processes	Size	Process	Ref % O ₂	Achievable concentrations, mgm ⁻³ , dry at 0°C, 101.3 kPa (at ref O ₂)					
				PM	SO ₂	NO _x	N ₂ O	CO	HCl
	MW _{th}								
		Retrofit PF/Grates Retrofit FBC	6	50	300	300		100-250 ⁴ 100-150 ⁴	25 ³
	100-300 MW _{th}	New PF/Grates New FBC	6	20	300	300 250		100-250 ⁴ 100-150 ⁴	25 ³
		Retrofit PF/Grates Retrofit FBC	6	50	300	300 250		100-250 ⁴ 100-150 ⁴	25 ³
	>300 MW _{th}	New PF/Grates New FBC	6	20	200	150		100-250 ⁴ 100-150 ⁴	25 ³
		Retrofit PF/Grates Retrofit FBC	6	50	200	200		100-250 ⁴ 100-150 ⁴	25 ³
Liquid fuels	50-100 MW _{th}	New	3	15	350(175 post 2008)	300		150	1-5
		Retrofit 1%S 1%S + DSI	3	<u>50</u>	<u>1700</u> <u>685</u>	<u>450</u>		30-50	1-5
	100-300 MW _{th}	New	3	15	200	150		150	1-5
		Retrofit 1% S 1%S + DSI	3	<u>50</u>	1700 400	<u>450</u>		30-50	1-5
	>300 MW _{th}	New	3	15	150	100		150	1-5
		Retrofit opt out opt in	3	<u>50</u>	<u>1700</u> <u>400</u>	<u>1400</u> <u>450-400</u> <u>(300-500MW)</u>		30-50	1-5
Liquid fuels		Engines CI	15	50	112 66 from 2008	150		150	
		Gas Turbines	15		112	<u>125</u>		100	

Fuels and processes	Size	Process	Ref % O ₂	Achievable concentrations, mgm ⁻³ , dry at 0°C, 101.3 kPa (at ref O ₂)					
				PM	SO ₂	NO _x	N ₂ O	CO	HCl
					66 from 2008				
Natural gas		New Gas Turbines (incl CCGT)	15	5	10	20 - 50		100	
		Existing GTs (incl CCGT) DLN water or Steam injection	15	5	10	75 110		100	
		Engines CI (dual fuel) SCR	15	20	50	100		450	
		Engines CI (dual fuel) Lean burn	15	20	50	150		150	
		Engines SI SCR	5			250		400	
		Engines SI Lean Burn pre 2005	5			250 500		400 1000	
		New Boilers (<100MW / >100MW)	3	5	10	<u>300</u> / 100		30-50	
		Existing Boilers (<500MW / >500MW)	3	5	10	<u>300</u> / <u>200</u>		50	
Industrial gas		All combustion plant	3 or 15	BAT is gas cleaning to remove fuel S and fuel PM	BAT is gas cleaning to remove fuel S and fuel PM	50		50	
Smokeless Fuels									

Fuels and processes	Size	Process	Ref % O ₂	Achievable concentrations, mgm ⁻³ , dry at 0°C, 101.3 kPa (at ref O ₂)					
				PM	SO ₂	NO _x	N ₂ O	CO	HCl
Combustor/Incinerator/Battery/Boiler Flue Gases				25		300		150	
Dryer Vents				25		300			
Battery Abatement				25					
Dryer Vents				25		300			
Screen Abatement				25					
Coal/oil liquor handling				25					
Carbon Black									
Boiler/CHP flue gases			10%	25	2300	500		150	
Dryer Flue Gases			10%	25	2300	500		150	
Process/Purge/dust filters			10%	10					
Other Processes	(Corrected to 3% O ₂ Liquid & Gas, 6% O ₂ solid fuels)								
Combustion process release points						300		150	
Other Release points									
Gasification		Liquid and gas	3% v/v	BAT is gas cleaning to remove S and PM 10-25	BAT is desulphurisation to remove S 97-99.8%	Use of low NO _x technology in heating burners 200		200	
		Solid fuels	6% v/v						
		GT oper'n	15% v/v						
GCC			15%	1mg/MJ	1	45		20	

General Note Releases values shown are for consolidated but not agglomerated units and NOx releases values under LCPD are 'not opted out' >2000 hr 5 yr rolling average

3.2.2 Emissions to water associated with the use of BAT

Guidance is given below on release concentrations (or mass release rates) achievable at the time of writing for key substances using the best combination of techniques for new processes. Refer to [Section 1.1](#) with regard to their use.

The Levels given below are achievable levels and are not emission limits. They are subject to the Environment Agency's assessment of BAT when framing conditions in a permit. Notwithstanding the existence of any discharge consents or agreements there is a requirement to use BAT to prevent or minimise the release of prescribed substances to controlled waters. Concomitant controls apply to releases to public sewers. Process water may contain relatively small levels of polluting substances, but because it may be used in large quantities the mass emissions of pollutants can be substantial. A policy of recirculating water within the process where practicable should be followed, supplemented with appropriate treatment prior to discharge.

The releases which are significant include water treatment plant, boiler plant, ash handling and transport, and cooling towers. Where releases to water are necessary then, by using techniques which are available to constrain releases, the flow weighted monthly average concentration in a final effluent under most circumstances will not exceed the achievable levels given below in [Table 3.2](#). The Regulator should set an annual mass emission limit for cadmium and mercury.

As an initial guide to the criteria for rendering harmless, continuous compliance with the Agency's conditions should be considered.

Limits in Permits may be set for mean or median values over long or short periods. The periods and limits selected should reflect:

- the manner in which the emission may impact upon the environment
- likely variations which will arise during operation within BAT
- possible failure modes and their consequences
- the capabilities of the monitoring and testing system employed

Consideration should be given to:

- Fuel type & composition
- Type of fuel & chemical storage facilities
- Type of fuel preparation
- Type of combustion process
- Type of cooling systems and water treatment
- Raw water quality
- Type of flue gas treatment systems
- Nature of combustion products

Where automatic sampling systems are employed, limits may be defined such that:

- not more than 5% of samples shall exceed the benchmark value

Where spot samples are taken:

- no spot sample shall exceed the benchmark value by more than 50%

Note that where water is abstracted from a non-mains supply, the limits should be set to limit any additional increase in emission concentration for a given substance over the background level. This may take the form:

Limit = (intake concentration)*(multiplicative factor) + (additive factor)

Table 3.2 Achievable releases to water in final effluent

Substance	Releases achievable by application of BAT ⁽¹⁾
Suspended solids	1-10 mg/l ⁽²⁾
Ammoniacal nitrogen	5 mg/l
Chloride, sulphate	
Cadmium	10 µg/l (0.01 mg/l) ⁽³⁾
Mercury	5 µg/l (0.005 mg/l) ⁽³⁾
Other heavy metals	95% removal
COD	⁽⁴⁾
pH	Typically 5-9. ⁽⁵⁾

Note 1: The above levels represent a flow weighted monthly average concentration. .

Note 2: Some processes release only very low levels of suspended solids, other releases maybe reduced to 10 mg/m³ or less using settling, flocculation and filtration techniques as appropriate.

Note 3: By precipitation and filtration which can be expected to achieve 70% reduction. Subsequent treatment in the biological treatment plant of the sewage treatment works will reduce this to below the limit of detection

Note 4: COD would be expected to be low. The actual levels permitted to be discharged will be a function of the sewage treatment plant and the receiving water. The operator should be able to identify the major contributors to the composition of any COD.

Note 5: May vary, depending in specific situation

3.2.3 Standards and obligations

In addition to meeting the requirements of BAT, there are other national and international standards and obligations that must either be safeguarded through the IPPC Permit or, at least, taken into account in setting Permit conditions. This is particularly the case for any EC-based EQSs.

EC-based EQ standards

IPPC: A Practical Guide explains how these should be taken into account and contains an annex listing the relevant standards. (See [Appendix 2](#) for equivalent legislation in Scotland and Northern Ireland). They can be summarised as follows:

Air quality

- Statutory Instrument 2000 No.928, Air Quality (England) Regulations 2000 gives air quality objectives to be achieved by:
 - 2005 for nitrogen dioxide
 - 2004 for SO₂ and PM₁₀
 - 2003 for CO, 1,3-butadiene and benzene
 - in two stages for lead by 2004 and 2008 respectively
- Statutory Instrument 2002 No. 3043 The Air Quality (England) (Amendment) Regulations 2002, which sets a tighter objective for CO and a longer-term objective for benzene to be achieved by 2010.

Water quality

- Directive 76/464/EEC on Pollution Caused by Dangerous Substances Discharged to Water contains two lists of substances. List I relates to the most dangerous, and standards are set out in various daughter Directives. List II substances must also be controlled. Annual mean concentration limits for receiving waters for List I substances can be found in SI 1989/2286 and SI 1992/337 the Surface Water (Dangerous Substances Classification) Regulations. Values for List II substances are contained in SI 1997/2560 and SI 1998/389. Daughter Directives cover EQS values for mercury, cadmium, hexachlorocyclohexane, DDT, carbon tetrachloride, pentachlorophenol, aldrin, dieldrin, endrin, isodrin, hexachlorobenzene, hexachlorobutadiene, chloroform, 1,2-dichloroethane, trichloroethane, perchloroethane and trichlorobenzene.

Other waters with specific uses have water quality concentration limits for certain substances. These are covered by the following Regulations:– SI 1991/1597 Bathing Waters (Classification) Regulations– SI 1992/1331 and Direction 1997 Surface Waters (Fishlife) (Classification) Regulations– SI 1997/1332 Surface Waters (Shellfish)

(Classification) Regulations– SI 1996/3001 The Surface Waters (Abstraction and Drinking Water) (Classification) Regulations

Future likely changes include:

Some air quality and water quality standards may be replaced by new ones in the near future.

The SED on the limitation of emissions of VOCs due to the use of organic solvents in certain activities and installations.

Other standards and obligations

Those most frequently applicable to most sectors are:

- Hazardous Waste Incineration Directive
- Waste Incineration Directive
- Large Combustion Plant Directive
- Reducing Emissions of VOCs and Levels of Ground Level Ozone: a UK Strategy (published by the Department of the Environment in October 1993. It sets out how the Government expects to meet its obligations under the UNECE VOCs Protocol to reduce its emissions by 30% (based on 1988 levels) by 1999, including the reductions projected for the major industrial sectors)
- Water Quality Objectives – assigned water quality objectives to inland rivers and water courses (ref. Surface (Rivers Ecosystem) Classification).
- The UNECE convention on long-range transboundary air pollution (negotiations are now underway which could lead to a requirement further to reduce emissions of NOx and VOCs. A requirement to further reduce SO₂ emissions from all sources has been agreed. The second Sulphur protocol (Oslo, 1994) obliges the UK to reduce SO₂ emissions by 80% (based on 1980 levels) by 2010).
- The Montreal Protocol
- The Habitats Directive (see [Section 4.3](#))
- Sulphur Content of Certain Liquid Fuels Directive 1999/32/EC (from 1 January 2003, the sulphur content of heavy fuel oil must not exceed 1% except when it is burnt in plants fitted with SO₂ abatement equipment. Sulphur levels in gas oil must not exceed 0.2% from 1 July 2000, and 0.1% from the start of 2008.)
- National Emission Ceilings Directive
- Emission Trading Directive

3.2.4 Units for benchmarks and setting limits in permits

Releases can be expressed in terms of:

- **“concentration”** (for example mg/l or mg/m³), which is a useful day-to-day measure of the effectiveness of any abatement plant and is usually measurable and enforceable. The total flow must be measured/controlled as well
- **“specific mass release”** (for example, kg/ product or input or other appropriate parameter), which is a measure of the overall environmental performance of the plant (including the abatement plant) compared with similar plants elsewhere
- **“absolute mass release”** (for example, kg/hr, t/yr), which relates directly to environmental impact

When endeavouring to reduce the environmental impact of an installation, its performance against each of these levels should be considered, as appropriate to the circumstances, in assessing where improvements can best be made.

When setting limits in Permits, the most appropriate measure will depend on the purpose of the limit. It may also be appropriate to use surrogate parameters, which reflect optimum environmental performance of plant as the routine measurement, supported by less frequent check-analyses on the final concentration. Examples of surrogate measures would be the continuous measurement of conductivity (after ion-exchange treatment) or total carbon (before a guard-column in activated carbon treatment) to indicate when regeneration or replacement is required.

The emission level figures given in this chapter are based on average figures, not on maximum, short term peak values, which could be expected to be higher. The emission levels given are based on a typical averaging period of not less than 30 minutes and generally not greater than 24 hours (water emission levels may have a longer averaging period).

3.2.5 Statistical basis for benchmarks and limits in permits

Conditions in Permits can be set with percentile, mean or median values over annual, monthly or daily periods, which reflect probable variation in performance. In addition, absolute maximum can be set.

Where there are known failure modes, which will occur even when applying BAT, limits in Permits may be specifically distilled, but with commensurate requirements to notify the Regulator and to take specific remedial action.

For water: UK benchmarks or limits are most frequently 95 percentile concentrations or absolute concentrations, (with flow limited on a daily average or maximum basis).

For air: benchmarks or limits are most frequently expressed as daily averages or, typically 95 percent of hourly averages.

3.2.6 Reference conditions for releases to air

The reference conditions of substances in releases to air from point-sources are:

Note: Authorisations should be drafted in terms of releases in mg/m³, g/hr, g/MJ or g/tonne of fuel as appropriate.

- For combustion gases:
 - dry
 - temperature 273K (0°C)
 - pressure 101.3kPa (1 atmosphere)and adjusted to oxygen content of
 - 3% v/v, dry for liquid and gaseous fuels burned at large boilers and furnaces, and
 - 15% v/v, dry for liquid and gaseous fuels burned at CI engines and gas turbines, and
 - 6% v/v, dry for solid fuels burned at large boilers and furnaces
- For non-combustion gases:
 - no correction for water vapour or oxygen content,
 - temperature 273K (0°C)
 - pressure 101.3kPa (1 atmosphere)

To convert measured values to reference conditions, see the **Monitoring Guidance** for more information.

4. Impact

4.1 IMPACT ASSESSMENT

The Operator should assess that the emissions resulting from the proposals for the activities/installation will provide a high level of protection for the environment as a whole, in particular having regard to EQS etc, revisiting the techniques in Section 2 as necessary. The use of **IPPC Environmental Assessments for BAT**, and the IPPC Environmental Assessments for BAT software tool, and the other tools on the Application CD, will lead the Applicant through the process.

The depth to which the impact assessment should go should be discussed with the Regulator. For some low risk sites the requirements may be reduced.

Indicative requirements for impact assessment
Provide an assessment of the potential significant environmental effects (including trans-boundary effects) of the foreseeable emissions.
<ol style="list-style-type: none">1. Provide a description, including maps as appropriate, of the receiving environment to identify the receptors of pollution. The extent of the area may cover the local, national and international (for example, transboundary effects) environment as appropriate.2. Identify important receptors, which may include: areas of human population including noise or odour-sensitive areas, flora and fauna (that is, Special Areas of Conservation (and including Sites of Community Importance or candidate Special Areas of Conservation) and Special Protection Areas (collectively known as "European sites") Sites of Special Scientific Interest (SSSI or in Northern Ireland ASSI) or other sensitive areas, soil, water, that is groundwater (water below the surface of the ground in the saturation zone and in direct contact with the ground and subsoil) and watercourses (for example, ditches, streams, brooks, rivers), air, including the upper atmosphere, landscape, material assets and the cultural heritage.3. Identify the pathways by which the receptors will be exposed (where not self-evident).4. Carry out an assessment of the potential impact of the total emissions from the activities on these receptors. IPPC Environmental Assessments for BAT provides a systematic method for doing this and will also identify where modelling needs to be carried out, to air or water, to improve the understanding of the dispersion of the emissions. The assessment will include comparison (see IPPC: A Practical Guide) with:<ul style="list-style-type: none">• community EQS levels• other statutory obligations• non-statutory obligations• environmental action levels (EALs) and the other environmental and regulatory parameters defined in IPPC Environmental Assessments for BAT5. In particular it will be necessary to demonstrate that an appropriate assessment of vent and chimney heights has been made to ensure that there is adequate dispersion of the minimised emission(s) to avoid exceeding local ground-level pollution thresholds and limit national and transboundary pollution impacts, based on the most sensitive receptor, be it human health, soil or terrestrial ecosystems.

Indicative requirements for impact assessment

Provide an assessment of the potential significant environmental effects (including trans-boundary effects) of the foreseeable emissions.

6. Where appropriate, the Operator should also recognise the chimney or vent as an emergency emission point and understand the likely behaviour. Process upsets or equipment failure giving rise to abnormally high emission levels over short periods should be assessed. Even if the Applicant can demonstrate a very low probability of occurrence, the height of the chimney or vent should nevertheless be set to avoid any significant risk to health. The impact of fugitive emissions can also be assessed in many cases.

7. Consider whether the responses to Sections 2 and 3 and this assessment adequately demonstrate that the necessary measures have been taken against pollution, in particular by the application of BAT, and that no significant pollution will be caused. Where there is uncertainty about this, the measures in Section 2 should be revisited as appropriate to make further improvements.

8. Where the same pollutants are being emitted by more than one permitted activity on the installation, the Operator should assess the impact both with and without the neighbouring emissions.

4.2 WASTE MANAGEMENT LICENSING REGULATIONS

Indicative requirements for waste management licensing regulations

Explain how the information provided in other parts of the application also demonstrates that the requirements of the relevant objectives of the Waste Management Licensing Regulations 1994 have been addressed, or provide additional information in this respect.

1. In relation to activities involving the disposal or recovery of waste, the Regulators are required to exercise their functions for the purpose of achieving the relevant objectives as set out in Schedule 4 of the Waste Management Licensing Regulations 1994. (For the equivalent Regulations in Scotland and Northern Ireland, see Appendix 2.)

2. The 'relevant objectives', contained in paragraph 4, Schedule 4 of the Waste Management Licensing Regulations 1994 (SI 1994/1056 as amended), are as follows:

ensuring the waste is recovered or disposed of without endangering human health and without using processes or methods which could harm the environment and in particular without:

risk to water, air, soil, plants or animals, or

causing nuisance through noise or odours, or

adversely affecting the countryside or places of special interest;

implementing, so far as material, any plan made under the plan-making provisions.

3. The application of BAT is likely to already address risks to water, air, soil, plants or animals, odour nuisance and some aspects of effects on the countryside. It will, however, be necessary for the Operator briefly to consider each of these objectives individually and provide a comment on how they are being addressed by your proposals. It is also necessary to ensure that any places of special concern that could be affected, such as SSSIs, are identified and commented upon although, again, these may have been addressed in your assessment for BAT, in which case a cross-reference may suffice.

Operators should identify any development plans made by the local planning authority, including any local waste plan and Waste Strategy 2000, and comment on the extent to which the proposals accord with the contents of any such plan (see also Section 2.6).

4.3 THE HABITATS REGULATIONS

Indicative requirements for the habitats regulations

Provide an assessment of whether the installation is likely to have a significant effect on a European site in the UK and, if it is, provide an assessment of the implications of the installation for that site, for the purpose of the Conservation (Natural Habitats etc.) Regulations 1994 (SI 1994/2716) and the Conservation (Natural Habitats etc.) Regulations (Northern Ireland) 1995.

1. An application for an IPPC Permit will be regarded as a new plan or project for the purposes of the Habitats Regulations (for the equivalent Regulations in Northern Ireland see Appendix 2). Therefore, Operators should provide an initial assessment of whether the installation is likely to have a significant effect on any European site in the UK (either alone or in combination with other relevant plans or projects) and, if so, an initial assessment of the implications of the installation for any such site. The application of BAT is likely to have gone some way towards addressing the potential impact of the installation on European sites and putting into place techniques to avoid any significant effects. The Operator should provide a description of how the BAT assessment has specifically taken these matters into account, bearing in mind the conservation objectives of any such site.

2. European sites are defined in Regulation 10 of the Habitats Regulations to include Special Areas of Conservation (SACs); sites of community importance (sites that have been selected as candidate SACs by member states and adopted by the European Commission, but which are not yet formally classified); and Special Protection Areas (SPAs). It is also Government policy (set out in PPG 9 on nature conservation) that potential SPAs and candidate SACs should be considered to be European sites for the purposes of Regulation 10.

3. Information on the location of European sites and their conservation objectives is available from:

- English Nature (01733 455000), www.english-nature.org.uk
- Countryside Council for Wales (01248 385620), www.ccw.gov.uk
- Scottish Natural Heritage (0131 447 4784), www.snh.gov.uk
- Joint Nature Conservation Committee (01733 562626), www.jncc.gov.uk
- Environment and Heritage Service, Northern Ireland (02890254754), www.ehsni.gov.uk

4. The Regulator will need to consider the Operator's initial assessment. If it concludes that the installation is likely to have a significant effect on a European site, then the Regulator will need to carry out an "appropriate assessment" of the implications of the installation in view of that site's conservation objectives. The Regulations impose a duty on the Regulator to carry out these assessments, so it cannot rely on the Operator's initial assessments. Therefore the Regulator must be provided with any relevant information upon which the Operator's assessment is based.

5. Note that in many cases the impact of the Habitats Regulations will have been considered at the planning application stage, in which case the Regulator should be advised of the details.

References

For a full list of available Technical Guidance see Appendix A of the Guide for Applicants or visit the Environment Agency Website <http://www.environment-agency.gov.uk>. Many of the references below are being made available free of charge for viewing or download on the Website. The same information can also be accessed via the SEPA web site <http://www.sepa.org.uk>, or the NIEHS web site www.ehsni.gov.uk. Most titles will also be available in hard copy from The Stationary Office (TSO). Some existing titles are not yet available on the Website but can be obtained from TSO

Ref. 1 *IPPC Reference Document on Best Available Techniques in the Textile Industry* European Commission <http://eippcb.jrc.es>

Ref. 2 *The Pollution Prevention and Control Act* (1999) (www.hmsso.gov.uk)

Ref. 3 *The Pollution Prevention and Control Regulations* (SI 2000 No . 1973) (www.hmsso.gov.uk)

Ref. 4 *IPPC: A Practical Guide* (for England and Wales) (or equivalents in Scotland and Northern Ireland) www.defra.gov.uk/environment/ppc/ippcguide/index.htm

Ref. 5 Guidance for applicants

= IPPC Part A (1) Installations: Guide for Applicants (England and Wales) (includes Preparation of a Site Report in a Permit Application) (**EA website**) .

=PPC Part A Installations: Guide for Applicants (Scotland) (Guidance for SEPA staff on land and groundwater considerations) **Guidance for SEPA staff on land and groundwater considerations**

- IPPC Regulatory Guidance Series No 5 – Interpretation of “Installation” in the PPC Regulations www.environment-agency.gov.uk

Ref. 6 Assessment methodologies:

- *E1 BPEO Assessment Methodology for IPC*
- *IPPC Environmental Assessments for BAT H1*

Ref. 7 Waste minimisation support references

- *Environment Agency web site*. Waste minimisation information accessible via: www.environment-agency.gov.uk/subjects/waste/131528
- *Waste Minimisation –an environmental good practice guide for industry* (helps industry to minimise waste and achieve national environmental goals). Available free to companies who intend to undertake a waste reduction programme (tel. 0345 33 77 00)
- *Waste minimisation Interactive Tools (WIMIT)*. Produced in association with Envirowise and BOC Foundation (a software tool designed for small and medium businesses). Available free from The Environmental Helpline (tel.: 0800 585794)
- *ENVIROWISE*. A joint DTI/DEFRA programme, with over 200 separate case studies, good practice guides, leaflets, flyers, software tools and videos covering 12 industry sectors, packaging, solvents and the generic areas of waste minimisation and cleaner technology.

ENVIROWISE is accessible via a FREE and confidential Helpline (tel. 0800 585794) or via the web site www.envirowise.gov.uk

- *Increased Profit Through Improved Materials Additions: Management/Technical Guide*, ENVIROWISE, GG194/195
- *Waste management Information Bureau*. The UK's national referral centre for help on the full range of waste management issues. It produces a database called Waste Info, which is available for on-line searching and on CD-ROM. Short enquiries are free (tel.: 01235 463162)
- *Waste Minimisation* – Institution of Chemical Engineers Training Package E07. Basic course which contains guide, video, slides, OHPs etc (tel.: 01788 578214)
- *BIO – WISE – profiting through industrial biotechnology*. A DTI programme providing free advice and information about how biotechnology can be used within manufacturing industry. Case studies, guides website and Helpline 0800 4321000.
Dti.gov.uk/biowise (leather guide GG237 and case study 11)

Ref. 8 Water efficiency references

- *Simple measures restrict water costs*, ENVIROWISE, GC22
- *Effluent costs eliminated by water treatment*, ENVIROWISE, GC 24
- *Saving money through waste minimisation: Reducing water use*, ENVIROWISE, GG26
- *ENVIROWISE Helpline 0800 585 794*
- *Optimum use of water for industry and agriculture dependent on direct abstraction: Best practice manual*. R&D technical report W157, Environment Agency (1998), WRc Dissemination Centre, Swindon (tel.: 01793 865012)
- *Cost-effective Water Saving Devices and Practices* ENVIROWISE GG067
- *Water and Cost Savings from Improved Process Control* ENVIROWISE GC110
- *Tracking Water Use to Cut Costs* ENVIROWISE GG152

Ref. 9 Releases to air references:

- BREF on Waste Water and Waste Gas Treatment
- A3 Pollution abatement technology for particulate and trace gas removal, 1994, £5.00, 0-11-752983-4
- Part B PG1/3 Boilers and Furnaces 20-50 MW net thermal input (ISBN 0-11-753146-4-7)
- Part B PG1/4 Gas Turbines 20-50 MW net thermal input (ISBN 0-11-753147-2)

Ref. 10 Releases to water references

- BREF on Waste Water and Waste Gas Treatment
- *A4 Effluent Treatment Techniques*, TGN A4, Environment Agency. ISBN 0-11-310127-9 (**EA website**)
- *Construction of bunds for oil storage tanks*, Mason, P. A Amies, H. J Sangrapillai, G. Rose. Construction Industry Research and Information Association (CIRIA), Report 163, 1997, CIRIA, 6 Storey's Gate, Westminster, London SW1P 3AU. Abbreviated versions are also available for masonry and concrete bunds (www.ciria.org.uk on-line purchase)
- *Policy and Practices for the Protection of Groundwater* (PPPG) (**EA website**)
- *Choosing Cost-effective Pollution Control* ENVIROWISE GG109

- *Cost-effective Separation Technologies for Minimising Wastes and Effluents* ENVIROWISE GG037
- *Cost-effective Membrane Technologies for Minimising: Wastes and Effluents* ENVIROWISE GG044

Ref. 11 Waste management references

- *Investigation of the criteria for, and guidance on, the landspreading of industrial wastes* – final report to the DEFRA, the Environment Agency and MAFF, May 1998

Ref. 12 Energy references

- *(Interim) Energy Efficiency Guidance*, (available as draft Horizontal Guidance Note IPPC H2) (www.environment-agency.gov.uk)

Ref. 13 COMAH guides

- *A Guide to the Control of Major Accident Hazards Regulations 1999*, Health and Safety Executive (HSE) Books L111, 1999, ISBN 0 07176 1604 5
- *Preparing Safety Reports: Control of Major Accident Hazards Regulations 1999*, HSE Books HS(G)190, 1999
- *Emergency Planning for Major Accidents: Control of Major Accident Hazards Regulations 1999* HSE Books HS(G) 191, 1999
- *Guidance on the Environmental Risk Assessment Aspects of COMAH Safety Reports*, Environment Agency, 1999 (**EA website**)
- *Guidance on the Interpretation of Major Accidents to the Environment for the Purposes of the COMAH Regulations*, DEFRA, 1999, ISBN 753501 X, available from the Stationary Office

Ref. 14 Monitoring Guidance

- = *MCERTS approved equipment* link via **www.mcerts.net**
- = *Technical Guidance Note M1 – Sampling requirements for monitoring stack emissions to air from industrial installations*, Version 2, Environment Agency 2002. www.environment-agency.gov.uk
- = *Technical Guidance Note M2 – Monitoring of stack emissions to air*, Version 2, Environment Agency, 2003. www.environment-agency.gov.uk
- = *Technical Guidance Note M18 – Monitoring of discharges to water*, Version 1, Environment Agency, 2004. www.environment-agency.gov.uk
- *Direct Toxicity Assessment for Effluent Control* Technical Guidance (2000), UKWIR 00/TX/02/07

Ref. 15 Noise References:

- = *H3 Horizontal Guidance for Noise Part 1 Regulation and Permitting*
- *H3 Horizontal Guidance for Noise Part 2 Assessment and Control*

Ref. 16 Closure references

- *Working at Construction and Demolition-sites (PPG 6)* (**EA website**)

Ref. 17 Air Dispersion

- *Guidelines on Discharge Stack Heights for Polluting Emissions*, HMIP Technical Guidance Note (Dispersion) D1, 1993, ISBN 0-11-752794-7 www.tso.co.uk/bookshop: (or www.environment-agency.gov.uk for summary only)

Ref. 18 Fire Fighting

= *BS 5908: Code of Practice for Fire Precautions in the Chemical Allied Industries*

- *PPG 18 – Managing Fire-water and major spillages*, Environment Agency Pollution Prevention Guidance Note (see Ref. 10)

Ref. 19 Volatile Organic Compounds

- *The Categorisation of Volatile Organic Compounds*, 1995 HMIP Report No DOE/HMIP/RR/95/009 (www.environment-agency.gov.uk)

Abbreviations

BAT	Best Available Techniques see IPPC A Practical Guide or the Regulations for further definition
BAT criteria	The criteria to be taken into account when assessing BAT, given in Schedule 2 of the PPC Regulations
BOD	Biochemical Oxygen Demand
BREF	BAT Reference Document
CEM	Continuous Emissions Monitoring
CHP	Combined heat and power plant
COD	Chemical Oxygen Demand
ELV	Emission Limit Value
EMS	Environmental Management System
EQS	Environmental Quality Standard
ETP	Effluent treatment plant
FOG	Fat Oil Grease
ITEQ	International Toxicity Equivalents
MCERTS	Monitoring Certification Scheme
NIEHS	Northern Ireland Environment and Heritage Service
SAC	Special Areas of Conservation
SECp	Specific Energy consumption
SEPA	Scottish Environment Protection Agency
SPA	Special Protection Area
TSS	Suspended solids
TOC	Total Organic Carbon
VOC	Volatile organic compounds

Appendix 1: Some common monitoring and sampling methods

The Agency's Technical Guidance Notes (Monitoring) M1, Sampling Requirements for Monitoring Stack Emissions to Air from Industrial Installations, and M2, Monitoring of Stack Emissions to Air, are available via the "Search Site" facility on the Agency's web page, <http://www.environment-agency.gov.uk/>, entering M1 or M2 as the keyword. These documents provide key references as regards more detailed insight into different approaches to monitoring stack emissions, sampling strategies and choice of technique, method and equipment. Relative advantages and disadvantages of continuous versus periodic measurements are summarised in Part 2 of M2. Situations where continuous monitoring (continuous emissions monitoring systems – CEMs) may be more appropriate are discussed further in Section 5 of this note. Manual sampling and analysis methods are used to meet periodic or intermittent regulatory monitoring requirements and in some cases for validation and calibration of CEMs.

Measurement methods for common substances to water

DETERMINAND	Method	Detection limit Uncertainty	Valid for range mg/l	Standard
Suspended solids	Filtration through glass fibre filters	1 mg/l 20%	10-40	ISO 11929: 1997, EN872 – Determination of suspended solids
COD	Oxidation with di-chromate	12 mg/l 20%	50-400	ISO 6060: 1989, Water Quality – Determination of chemical oxygen demand
BOD5	Seeding with micro-organisms and measurement of oxygen content	2mg/l 20%	5-30	ISO 5815: 1989, Water Quality Determination of BOD after 5 days, dilution and seeding method EN 1899 (BOD 2 Parts)
AOX	Adsorption on activated carbon and combustion	-- 20%	0.4-1.0	ISO 9562: 1998 EN1485 – Determination of absorbable organically bound halogens
Tot P				BS 6068: Section 2.28 1997, Determination of phosphorus-ammonium molybdate spectrometric method
Tot N				BS 6068: Section 2.62 1998, Determination of nitrogen Part 1 Method using oxidative digestion with peroxydisulphate BS EN ISO 11905
pH				SCA The measurement of electric conductivity and the determination of pH ISBN 0117514284
Turbidity				SCA Colour and turbidity of waters 1981, ISBN 0117519553\EN 27027: 1999
Flow rate	Mechanical ultrasonic or electromagnetic gauges			SCA Estimation of Flow and Load, ISBN 011752364X
Temperature				
TOC				SCA The Instrumental

				Determination of Total Organic Carbon and Related Determinants 1995, ISBN 0117529796 EN 1484: 1997
Fatty Acids				Determination of Volatile Fatty Acids in Sewage Sludge 1979 ISBN 0117514624
Metals				BS 6068: Section 2.60 1998, Determination of 33 elements by inductively coupled plasma atomic emission spectroscopy
Chlorine				BS6068: Section 2.27 1990, Method for the determination of total chlorine: iodometric titration method
Chloroform Bromoform				BS 6068: Section 2.58, Determination of highly volatile halogenated hydrocarbons – Gas chromatographic methods
Dispersants Surfactants Anionic Cationic Non-ionic				SCA Analysis of Surfactants in Waters, Wastewaters and Sludges ISBN 01176058 EN 903:1993 (Used for anionic surfactants)
Pentachloro-Phenol				BS5666 Part 6 1983, Wood preservative and treated timber quantitative analysis of wood preservatives containing pentachlorophenol EN 12673: 1997 (used for chlorophenol and polychlorinated phenols)
Formaldehyde				SCA The determination of formaldehyde, other volatile aldehydes and alcohols in water
Phosphates and nitrates				BS 6068: Section 2.53 1997, Determination of dissolved ions by liquid chromatography
Sulphites and sulphates				BS 6068: Section 2.53 1997, Determination of dissolved ions by liquid chromatography
Ammonia				BS 6068: Section 2.11 1987, method for the determination of ammonium: automated spectrometric method
Grease and oils	IR absorption	0.06mg/kg		SCA The determination of hydrocarbon oils in waters by solvent extraction IR absorption and gravimetry ISBN 011751 7283

Measurement methods for air emissions

DETERMINAND	Method	Averaging time Detection limit Uncertainty	Compliance criterion	Standard
Formaldehyde	Impingement in 2,4 dinitro-phenyl-Hydrazine HPLC`	1 Hour 1mg/m ³ 30%	Average of 3 consecutive samples below specified limit	US EPA Method 316 Method specific to formaldehyde
Ammonia	FTIR or Ion Chromatography	1 hour 0.5mg/m ³ 25%		US EPA Method 320 for extractive instruments. US EPA Method 26 for wet chemistry
VOCs	Speciated-Adsorption Thermal Desorption GCMS	1 hour 0.1 mg/m ³ 30 %		BS EN 1076: 1997 Workplace atmospheres. Pumped sorbent tubes for the determination of gases and vapours. Requirements and test methods
	Total Organic Carbon	1 hour 0.4 mg/m ³ calculated	Continuous or spot check	BS EN 12619: 1999. Determination of the mass concentration of total gaseous organic carbon at low concentrations in flue gases continuous flame ionisation method 3
Chloroform	Absorption on activated carbon solvent extraction GC analysis	1 hour 1mg/m ³ 20%	Average of 3 consecutive samples below specified average	MDHS 28 Chlorinated hydrocarbon solvent vapours in air (modified)
Oxides of Sulphur	UV fluorescence Automatic analyser	1 hour 1ppm 10%	95% of hourly averages over a year below specified limit	BS6069 Section 4.4: 1993 (ISO 7935) Stationary source emissions- determination of mass concentrations of sulphur dioxide
	Wet sampling train Ion chromatography	1 hour 1mg/m ³ 25%	Average of 3 consecutive samples below specified limit	BS6069 Section 4.1: 1998 (ISO 7934) Method for the determination of the mass concentration of sulphur dioxide-hydrogen peroxide/barium perchlorate method
Hydrogen Chloride	Wet sampling 3 analytical methods	30 minute minimum 0.2mg/m ³ calculated	One test	BS EN 1911: Parts 1-3: 1998 Manual method of determination of HCL
Particulate matter	Extractive – sample train	3 minutes per point 5mg/m ³ 10%	One test	BS EN 13284-1: 2002 Determination of low range mass concentration of dust – Part 1: Manual gravimetric method

	Continuous – Automatic analyser	Continuous N/A 10%	Continuos	BS ISO 10155: 1995 Automated Monitoring of mass concentrations of particles – performance characteristics, test methods and specifications
PCDD/F	Extractive – Sample train GC/MS	4 hour minimum 8 hour maximum 0.1 ng l – TEQ/m ³ calculated		BS EN 1948: 1997 determination of the mass concentration of PCDD/F

Measurement uncertainty is defined as total expanded uncertainty at 95% confidence limit calculated in accordance with the Guide to the Expression of Uncertainty in Measurement, ISBN 92-67-10188-9 1st Ed., Geneva, Switzerland, ISO 1993.

See also **Monitoring Guidance**

Appendix 2: Equivalent legislation in Scotland & Northern Ireland

The legislation referred to in the text is that for England. The following are the equivalents for Scotland, Wales and Northern Ireland.

Equivalent Legislation

ENGLAND	WALES	SCOTLAND	N. IRELAND
PPC Regulations (England and Wales) 2000, SI 2000 No 273 (as amended)	As England	PPC (Scotland) Regulations 2000, SSI 2000 No 323 (as amended)	PPC (NI) Regulations 2003, SR 2003 No. 323
SI: 1994 1056: Waste Management Licensing Regulations	As England	As England	SR 2003 No 493: The Waste Management and Licensing Regulations (NI) 2003
The Water Resources Act 1991	As England	COPA 1974 (S30A-30E equiv. to Part III WRA91): Natural Heritage (Scotland) Act 1991 (Part II equiv. to Part I WRA 91)	The Water (NI) Order 1999
SI 1989 No. 317: Clean Air, The Air Quality Standards Regulations 1989 SI 1995 No. 3146: The Air Quality Standards (Amendments) Regulations 1995 SI 2002 No. 3043 The Air Quality (England) (Amendment) Regulations 2002	As England SI 2002 No. 3182 (W.298) The Air Quality (Amendment) (Wales) Regulations 2002	As England SSI 2002 No. 297 The Air Quality (Scotland) Amendment Regulations 2002	SR 1990 No. 145: The Air Quality Standards Regulations (Northern Ireland) 1990 SR 1996 No.23: The Air Quality Standards (Amendments) Regulations (Northern Ireland) 1996
SI 2000 No. 928: The Air Quality (England) Regulations 2000 SI 2002 No. 3117 The Air Quality Limit Values (Amendment) Regulations 2002	SI 2000 No. 1940 (W.138): The Air Quality (Wales) Regulations 2000 SI 2002 No 3183 (W.299) The Air Quality Limit Values (Wales) Regulations 2002	SSI 2000/97: The Air Quality (Scotland) Regulations SSI 2002 No. 566 The Air Quality Limit Values (Scotland) Amendment Regulations 2002	No NI equivalent
SI 2001 No 2315: The Air Quality Limit Values Regulations 2001	SI 2001 No. 2683 (W.224): The Air Quality Limit Values (Wales) Regulations 2001	SSI 2001 No 224: The Air Quality Limit Values (Scotland) Regulations 2001	SI 2002 No 94: The Air Quality Limit Values (Northern Ireland) Regulations 2002
SI 1989 No 2286 and 1998 No 389: The Surface Water (Dangerous Substances Classification) Regulations. (Values for List II substances	As England	SI 1990/126: Surface Water (Dangerous Substances) (Classification) (Scotland) Regulations	Surface Waters (Dangerous Substances) (Classification) Regulations 1998. Statutory Rules of Northern Ireland 1998

are contained in SI 1997/2560 and SI 1998-389)			No 397
SI 1991 No 1597: Bathing Waters (Classification) Regulations 1991	As England	SI 1991 No. 1609: Bathing Waters (Classification) (Scotland) Regulations 1991	The Quality of Bathing Water Regulations (NI) 1993
SI 1997 No. 1331: The Surface Waters (Fishlife) (Classification) Regulations 1997	As England	SI 1997 No. 2471 (S.163): The Surface Waters (Fishlife) (Classification) (Scotland) regulations 1997	The Surface Water (Fish-life) (Classification) Regulations (NI) 1997
SI 1997 No. 1332: The Surface Waters (Shellfish) (Classification) Regulations 1997	As England	SI 1997 No. 2470 (S.162): The Surface Waters (Shellfish) (Classification) (Scotland) Regulations 1997	The Surface Water (Shellfish) (Classification) Regulations (NI) 1997
SI 1994 No. 2716: The Conservation (Natural Habitats, etc) Regulations	As England	As England	Conservation (Natural Habitats etc) Regulations (Northern Ireland) 1995
SI 1999 No. 743: Control of Major Accident Hazards regulations (COMAH) 1999	As England	As England	SR 2000 No. 93: Control of Major Accident Hazards Regulations (Northern Ireland) 2000
SI 1998 No. 2746: The Groundwater Regulations 1998	As England	As England	SR 1998 No 401. The Groundwater Regulations (Northern Ireland) 1998
SI 2002 No. 2980: The Waste Incineration (England and Wales) Regulations 2002	As England	SSI 2003 No. 170: The Waste Incineration (Scotland) Regulations 2003	SR 2003 No 390: The Waste Incineration Regulations (Northern Ireland) 2003

Appendix 3: Groundwater Regulations 1998 Schedule of listed substances and recommendations for List 1 (DEFRA)

List I

1. -(1) Subject to the sub paragraph below, a substance is in List I if it belongs to one of the following families or groups of substances:

- (a) organohalogen compounds and substances that may form such compounds in the aquatic environment
- (b) organotin compounds
- (c) substances that possess carcinogenic, mutagenic or teratogenic properties in or via the aquatic environment (including substances that have those properties that would otherwise be in List II)
- (d) mercury and its compounds
- (e) cadmium and its compounds
- (f) mineral oils and hydrocarbons
- (g) cyanides

1. -(2) A substance is not in List I if it has been determined by the Regulator to be inappropriate to List I on the basis of a low risk toxicity, persistence and bioaccumulation.

List II

2. -(1) A substance is in List II if it could have a harmful effect on groundwater and it belongs to one of these families or groups of substances

- (a) the following metalloids and metals and their compounds:

zinc	tin	copper
barium	nickel	beryllium
chromium	boron	lead
uranium	selenium	vanadium
arsenic	cobalt	antimony
thallium	molybdenum	tellurium
titanium	silver	

- (b) biocides and their derivatives not appearing in List I
- (c) substances that have a harmful effect on the taste or odour of groundwater, and compounds liable to cause the formation of such substances in such water and to render it unfit for human consumption
- (d) toxic or persistent organic compounds of silicon, and substances that may cause the formation of such compounds in water, excluding those which are biologically harmless or are rapidly converted in water into harmless substances
- (e) inorganic compounds of phosphorus and elemental phosphorus
- (f) fluorides
- (g) ammonia and nitrates.

2.-(2) A substance is also in List II if:

- (a) it belongs to one of the families or groups of substances set out in paragraph 1(1) above
- (b) it has been determined by the Regulator to be inappropriate to List I under paragraph 1(2): and
- (c) it has been determined by the Regulator to be inappropriate to List II having regard to toxicity, persistence and bioaccumulation

3.-(1) The Secretary of State or Scottish Ministers may review any decision of the Regulator in relation to the exercise of its powers under the paragraphs above.

3.-(2) The Secretary of State or Scottish Ministers shall notify the Regulator of his decision following a review under List I sub paragraph 1 above and it shall be the duty of the Regulator to give effect to that decision.

4.- The Regulator shall from time to time publish a summary of the effect of its determinations under the Schedule in such manner as it considers appropriate and shall make copies of any such summary available to the public free of charge.

List of substances recommended to be confirmed as List I

- as recommended by the Joint Agency Groundwater Directive Advisory Group.

Aldrin	Diuron
Atrazine	Endosulfan
Azinphos-ethyl	Fenitrothion
Bromoxynil (as Bromoxynil-phenol)	Fenthion
Bromoxynil octanoate	Heptachlor

Cadmium	Hexachlorobenzene
2-Chloroaniline	Hexachlorobutadiene (HCBD)
Chlorobenzene	Hexachlorocyclohexane
Chlordane	Hexachloroethane
Chloro-2, 4-dinitrobenzene	Hexachloronorborene
Chlorfenvinphos	Hexaconazole
4-Chloro-3-methylphenol	3-Iodo-2-propionyl n-butyl carbamate (IPBC)
Chloro-2-nitrobenzene	Linuron
Chloro-3-nitrobenzene	Malathion
Chloro-4-nitrobenzene	Mercury
2-Chlorophenol	Mevinphos
Chlorothalonil	Oxydemeton-methyl
2-Chlorotoluene	Parathion
a-Chlorotoluene	Parathion-methyl
Chlorpyrifos	Pentachlorobenzene
Coumaphos	Pentachloroethane
Cypermethrin	Pentachlorophenol (PCP)
DDT	Permethrin
Demeton	Propanil
Diazinon	Simazine
Dibutyl bis(oxylauroyl)tin	Tetrabutyltin
Dichlofluanid	1,2,4,5 – Tetrachlorobenzene
Dichloroaniline	Tetrachloroethylene
1,2-Dichlorobenzene	Triazophos
1,3-Dichlorobenzene	Tributyl tin oxide (TBTO)
1,4-Dichlorobenzene	Tributyl-phosphate
Dichloronitrobenzene (all isomers)	Trichlorfon
2,4-Dichlorophenol	1,2,4-Trichlorobenzene

1,3-Dichloropropene	Trichloroethylene
Dichloroprop	Trichlorophenol (all isomers)
Dichlorvos	Trifluralin
Dicofol	Triphenyl tin oxide (TPTO)
Dieldrin	Triphenyl-phosphate
Dimethoate	

Appendix 4: List of Changes

Table 4.4: List of Changes

Change	Reason	Author	Authorised by	Date