Efficiency and emissions monitoring and reporting

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Abstract

As concern about emissions and the environmental footprint of energy production grows, it is increasingly evident that more accurate information on emissions of CO_2, SO_2, NOx and trace pollutants from fossil fuel power plants will be needed. Since the determining factors for these emissions are coal characteristics and power plant efficiency, it is also necessary to be able to assess the performance of a coal plant. Power plant efficiency data are calculated at most plants in developed countries but are often considered commercially sensitive. Accurate information for plants in developing countries is not systematically obtained. There are several different methods available to estimate power plant efficiency and this lack of standardisation is proving a barrier to allowing direct comparison between plants. Benchmarking has been tried in countries such as the Netherlands in a move towards determining the best performing plants and to set a target level for less-efficient plants.

In developed nations and in an increasing number of emerging economies, power plant emissions must be measured and maintained below legislated limits. Although there are basic principles used in any system designed to monitor emissions such as CO_2, SO_2 or mercury, the actual techniques and equipment used can vary significantly. This, and variation in the way these monitoring systems are applied, means that there is, as yet, no internationally standardised approach to measuring pollutant emissions.

This report summarises the techniques and equipment used to determine efficiency and pollutant emissions at coal-fired plants and discusses how the data from these systems are used to comply with the various permits, legislation and action plans that apply to coal-fired power plants in different countries.

Abbreviations

AAS	atomic absorption spectroscopy
AMS	automated monitoring system (CEM)
APEC	Asia-Pacific Economic Cooperation
ARP	Acid Rain Program, USA
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
BACT	best available control technology, USA
BAT	best available technology, EU
BREF	best available technology reference document, EU
Btu	British thermal unit
CAA	Clean Air Act, USA
CAMR	Clean Air Mercury Rule
CCS	carbon capture and storage
CEM	continuous emissions monitor
CEN	Comité Européan de Normalisation (European Standards Committee)
CIAB	Coal Industry Advisory Board
CCME	Canadian Council of Ministers for the Environment
CFR	Code of Federal Regulations, USA
COE	corrected operational efficiencies
CO_2-e	CO_2 equivalent
CS	country specific
CV	calorific value
CVAF	cold vapour atomic fluorescence (spectroscopy)
CWS	Canada-Wide Standard
DAHS	data acquisition and handling systems
DOAS	differential optical absorption spectroscopy
EC	European Commission
ECD	electron capture detection
EF	emission factor
ELV	emission limit value
E-PRTR	European Pollutant Release and Transfer Register
ESP	electrostatic precipitator
ETS	emissions trading scheme, EU
EU	European Union
FASB	Financial Accounting Standards Board, USA
FID	flame ionisation detection
FGD	flue gas desulphurisation
FTIR	Fourier transform infrared (spectroscopy)
GC	gas chromatography
e-GGRT	electronic greenhouse gas reporting tool, US EPA
GCV	gross calorific value
GES	Generator Efficiency Standards, Australia
GGRS	Greenhouse Gas Reduction Scheme, Australia
GHG	greenhouse gas
GHGRP	Greenhouse Gas Reporting Program, US EPA
HHV	higher heating value
HR	heat rate
IASB	International Accounts Standards Board
IEA	International Energy Agency
IED	Industrial Emissions Directive, EU

IPCC	Intergovernmental Panel on Climate Change
IPPC	Integrated Pollution Prevention and Control, EU
IR	infrared (spectroscopy)
ISO	International Standards Organisation
LCPD	Large Combustion Plant Directive, EU
LHV	lower heating value
LLD	limited life derogation
LME	low mass emitter
LOI	loss on ignition
LRTAP	Long Range Transboundary Air Pollution
MACT	maximum achievable control technique/technology
MCERTS	monitoring certification scheme, UK
MEP	Ministry for Environmental Protection, China
MS	mass spectrometry
MSG	minimum stable generation
NBTP	NOx Budget Trading Program, USA
NCV	net calorific value
NDIR	non-dispersive infrared (spectroscopy)
NDUV	non-dispersive ultraviolet (spectroscopy)
NECD	National Emissions Ceilings Directive, EU
NEI	National Emission Inventory, USA
NERP	National Emission Reduction Plan, EU
NESCAUM	Northeast States for Coordinated Air Use Management, USA
NPI	National Pollutant Inventory, Australia
NSPS	New Source Performance Standards, USA
NSR	New Source Review, USA
NSW	New South Wales, Australia
OECD	Organisation for Economic Cooperation and Development
OP	operating permit, USA
PAH	polycyclic aromatic hydrocarbons
PCDD	polychlorinated dibenzo dioxin
PCDF	polychlorinated dibenzo furan
PEM	predictive emissions monitoring
PM	particulate matter
PPC	pollution prevention and control, UK
PRTR	pollutant release and transfer register, UK
PS	performance specification
QA/QC	quality assurance and quality control
SFV	specific flue gas volume
SHR	station heat rate
SRM	standard reference method
STAC	Source Testing Accreditation Council
SUSD	start-up and shut-down
TDL	tunable diode laser
TEOM	tapered element oscillating microbalance
TJ	terrajoule
TRI	Toxics Release Inventory, USA
TÜV	Technical Inspection Association, Germany
UHR	unit heat rate
UK EA	UK Environment Agency
US EIA	US Energy Information Administration
US EPA	US Environmental Protection Agency
UV	ultraviolet
VDI	Verein Deutscher Ingenieure (German Standards Organisation)

VOC	volatile organic compound
WBCSD	World Business Council on Sustainable Development
WBG	World Bank Group
WCI	World Coal Institute
WRI	World Resources Institute
WT	world’s top (performing power plants)

Contents

1 Introduction

Pollution control and reduction requires the accurate quantification of emissions from target sources, including coal-fired power plants. As shown in Figure 1, there is a hierarchy between the environmental objective of any pollution control strategy and monitoring and compliance at the target sources. Most legislation to reduce emissions is in the form of either maximum emission limits or target emission reduction values (Sloss, 2003). In order for this legislation to be effective, the emissions must be accurately quantified and reported to the regulatory authority and action must be taken to ensure compliance. Reporting requirements vary throughout the world according to local, national and international legislation and action plans. In most situations, the methods for measuring and monitoring emissions use either commercially-based automated monitoring systems or manual methodologies which are based on empirical assumptions. However, despite this, different requirements and methodologies have been developed independently around the world. This report reviews the different methods and technologies that are used to ensure that coal-fired power plants comply with applicable emission legislation and related performance requirements.

There are two major approaches to determining emissions: estimation (based on emission factors) and measurement (based on actual monitoring of emissions at the source). National and international emission inventories are commonly based on the use of emission factors, as discussed in a previous report by Sloss (2009b). Compliance monitoring, on the other hand, tends to be a real-time continuous measurement approach with the methods being applied to ensure that emissions do not exceed the specified limit at any time. Since the emission factors used for inventories are produced and modified with emission measurement data, the two approaches always overlap. This current report concentrates on methods used for compliance monitoring. The interested reader is referred to the 2009 report for more information on inventory calculations.

There are several types of monitoring and reporting carried out at most coal-fired power plants. Efficiency monitoring or estimation is required to ensure that a plant is working under optimum conditions so that energy production is maximised and fuel costs minimised. Efficiency improvements also result in decreased pollutant emissions. Improving plant efficiency is therefore potentially a

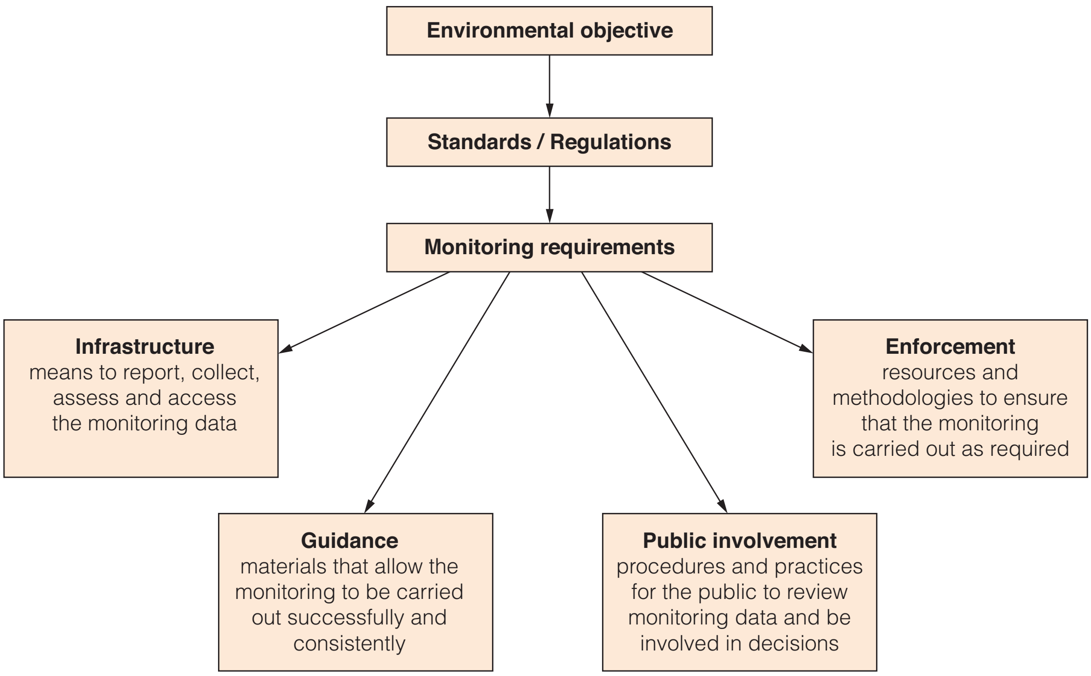

Figure 1 Environmental monitoring framework (APEC, 2008)

significant method for emission reduction. Chapter 2 explains the different ways plants can either measure or estimate their operating efficiency.

As mentioned above, there are several different ways power plants can report emissions, from simply estimating emissions based on emission factors to more plant-specific and real-time data produced online with continuous emissions monitoring systems. These options are discussed in Chapter 3.

The major atmospheric pollutants, such as particulates, SO_2 and NOx, are now controlled, or soon will be, at most plants in the developed world. Chapter 4 reviews the different automatic and manual options for monitoring these species. Details for measuring or estimating CO_2 emissions and emissions of trace pollutants such as halogens and trace elements are also summarised in Chapter 4. Although the methodologies for pollution monitoring are based on empirical calculations or techniques, there are often different approaches which are defined as the standard method in different regions of the world. Chapter 5 summarises the differences in approaches and legislative basis for emissions monitoring internationally.

2 Measurement and estimation of plant efficiency

Plant efficiency is arguably the major focus for any utility or plant operator. There are obvious and significant advantages to improving the efficiency of power generating systems (CIAB, 2010):

- prolonging the life of coal reserves and resources by reducing consumption;
- increasing power output;
- potentially reduced operating costs;
- reducing emissions of CO_2 and conventional pollutants.

The first three items on the list are prioritised by the plant in order to keep costs down and income up. Previous reports by the IEA Clean Coal Centre dealt with the methods to improve the efficiencies of coal-fired plants in developing countries (Henderson, 2003) and good practice for industrial boilers (Kessels, 2009). The interested reader is referred to these documents for more information.

It is the last item on the above list – the issue of pollutant emissions – that is the focus of this report. Plant efficiency is one of the key factors in determining and controlling emissions – the more efficiently a plant operates, the less fuel it requires and the less pollution it emits. It has been estimated that 1.7 $GtCO_2$ could be saved annually by improving the efficiency of existing plants worldwide. In a report by Henderson (2003) it was estimated that improving the net efficiency of plants in China by 4% (on a lower heating value, LHV basis and considering over 150 GWe) could reduce SO_2 emissions by 1129 kt/y and NOx emissions by 459 kt/y. Similarly, a 4–5% net efficiency improvement on 53 GWe of capacity in India could reduce SO_2 emissions by 790 kt/y (taking coal washing into account) and NOx emissions by 178 kt/y. Although it may not be possible in practice to achieve this, monitoring the efficiency of plants, and targeting those that perform poorly for upgrading or closure, could be an important way of reducing greenhouse gas (GHG) emissions (CIAB, 2010). Kaupp (2005) has published an interesting article on how to calculate the financial attractiveness of investments in efficiency improvements on plants in India and the interested reader is referred to the original paper for further information.

The potential for improvements in plant efficiency to be used as a means of reducing emissions is being recognised in some countries as a potential basis for possible regulatory action. For example, at the end of 2010 the US Environmental Protection Agency (US EPA) released a guidance document under the Clean Air Act (CAA) recommending that air regulators strongly emphasise the role of energy efficiency in GHG emissions control (Holly, 2010). Similarly, the World Bank Group guidelines on environmental, health and safety guidelines for thermal power plants include a section on the importance of energy efficiency in reducing GHG emissions (WBG, 2008). The WBG recommend that new facilities aim to attain the performance of the top quartile (25%) of the country/region average of the same fuel type and power plant size. They also recommend that existing facilities be rehabilitated to achieve significant improvements in efficiency.

According to Peltier (2010), the average coal-fired plant in the USA has a thermal efficiency of 32.5% (based on the higher heating value, HHV). It is recognised that this value, quoted by the US Energy Information Administration (US EIA), has an undetermined uncertainty because of 'disparate data sources'. It is clear that there is a significant lack of reported information on actual plant efficiency, even in developed countries. The World Coal Institute (WCI) estimates an average global efficiency of 28% for coal-fired plants worldwide. However without a universal standard for determining plant efficiencies, these numbers will remain 'best guesses'.

One of the main problems with comparing plant efficiency is that there is some confusion over how best to measure efficiency in practice. As stressed by Garwood and Jones (2008), efficiency is generally simple to define in theory but can be difficult to measure with accuracy and repeatability. Also, several alternative types of efficiency exist which can lead to confusion.

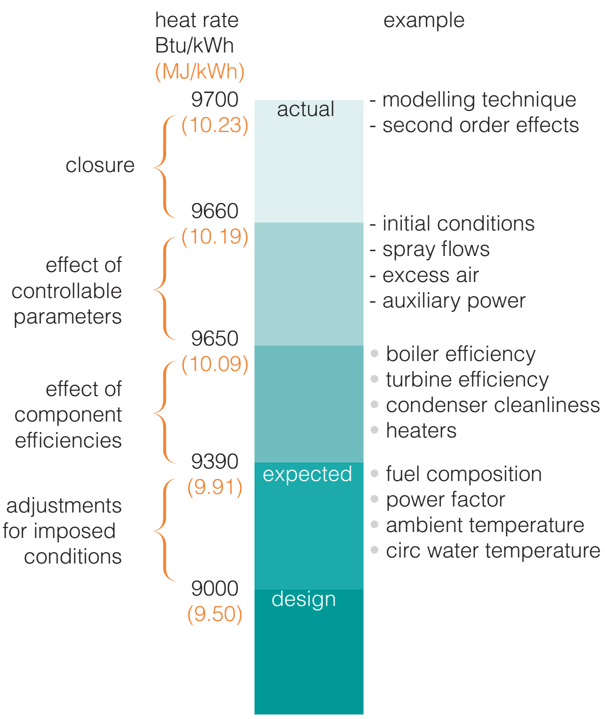

Figure 2 Departure of power plant performance from the original design (Wong and Takashi, 1994)

When discussing the efficiency of a plant or boiler, operators may give data based on gross power ratings, thermal efficiencies based on the calorific value of the coal, or simply cite the design efficiency – that is, the efficiency the boiler was designed to run at when it was first installed. However, the operational net electric efficiency of a power plant is not equal to the design efficiency. Figure 2 shows the factors which can cause a plant to perform below the design efficiency. It is beyond the scope of this report to discuss these different factors in detail. However, the following sections will provide some basic information of how these factors can be taken into account, where possible, to help determine the actual performance efficiency of a coal-fired power plant.

Before discussing the issues with standardising the reporting of power plant efficiency, it is important to understand the definitions and factors involved and then to look at the different calculations which are routinely used to estimate different forms of efficiency.

2.1 Definitions and factors

In the simplest of terms, the efficiency of a power station, η, should be defined as follows (Roth, 2005):

$$\eta = \text{electricity produced/energy input}$$

The basis for the data quoted most often on plant efficiency is, as mentioned before, the design efficiency. This is a value quoted by the equipment supplier on the basis of a specified fuel or fuel property range, and a 'maximum continuous rating'. This rating is equal to the performance test value for a new plant during a controlled period using the design fuel after the plant has stabilised at its nominal full output (IEA, 2007).

However, part of the confusion with determining plant efficiency is that there are several definitions and forms of efficiency (CAIB, 2010; IEA 2007; Roth, 2005), where equations for these definitions are available, these are given in Appendix 1:
Design efficiency: the efficiency at which new plant are designed to run, as discussed above.
Economic efficiency: the specific cost of producing useful output. This is usually the main driver behind shaping process plant design and operation.
Thermal efficiency: is the useful output energy for a given quantity of gross input heat energy, thermal input/thermal or electrical output
Energy efficiency: a measure of the useful energy from a process relative to the energy input – the energy conversion efficiency. This is also known as the 'input-output efficiency', the gross output, the gross efficiency or the total process output. In a utility, this is often referred to as 'generated power', although it does not take into account any plant losses, as with the operational efficiency.
Operational efficiency: also known as the capacity factor or load factor. This measures the actual

output from a process compared to the potential maximum output. This takes factors such as partial load operation, fuel quality effects and condenser temperature into account. This is commonly lower than the design efficiency although the difference is small for new or well-maintained plants operating at high capacity. This is also known as the net output/net efficiency – total process output minus the proportion energy used by the process itself. In a utility, this is often referred to as 'sent- out' power or 'gross-net'. If there are several units at a plant then the output may be referred to as 'gross-net-net' or 'station net export'.

2.2 Units and calculations

Appendix 1 summarises the common equations used to calculate power plant performance and efficiency. The Appendix also includes the calculations used to determine the capacity and load factors of the plant as well as the economic, operational and net efficiencies of the plant. The heat rate of the plant is calculated from the energy supplied by the fuel relative to the electricity output. The gross calorific value (GCV) of a fuel, also known as the higher heating value (HHV), is a measure of its heat of combustion assuming that all the water in the flue gas is condensed. The net calorific value (NCV), or lower heating value (LHV), excludes this latent heat. According to Peltier (2010), the use of the LHV to calculate efficiency is questionable since it would imply that a modern condensing boiler could achieve 100% or higher heating efficiency. A further complication is that the reference temperature used for determination is 25°C whereas other temperatures can be used (after correction). This can result in different apparent heat outputs. The use of LHV rather than HHV can increase the reported plant efficiency by as much as 10%, depending on the water and hydrogen content of the coal. For steam coals the difference is usually 3–4% but may be as much as 20% higher for some lignites (IEA, 2007). European plants tend to use LHV to report thermal efficiencies whereas plants in the USA tend to use the HHV. This means that European plants report efficiency numbers which may be 5–10% higher than those from similar plants in the USA, depending on the coal characteristics (Peltier, 2010).

British Standard BS 1016 calculates the NCV/LHV based on the moisture of the coal but also takes the hydrogen and crystalline moisture in the ash into account. Spreadsheets are available which calculate the NCV/LHV from coal data. The hydrogen in the coal can have a significant effect on the moisture in the flue gas. A coal with 9% moisture and 2% hydrogen will produce 5% moisture in the flue gas (at 6% O_2). However, if the hydrogen is excluded then the same 9% moisture in the coal will only produce 2% moisture in the flue gas (Keir, 2011).

Boiler manufacturers, who concentrate on the performance capabilities of their equipment, tend to calculate boiler efficiency based on the LHV. Moisture and hydrogen in the fuel will have a negative effect on the boiler efficiency because moisture absorbes heat and carries it out of the boiler. The manufacturers are more interested in the heat transfer of the boiler than any potential losses. Therefore, to determine actual boiler efficiency in practice, the GHV/HHV is more appropriate (Keir, 2011).

Power plants produce energy in the form of both heat and electrical power. In most utilities (those that are not combined heat and power plants) only the electric power is considered as the output. However, combined heat and power plants have an overall energy efficiency that is a result of the two combined (CIAB, 2010). Combined heat and power plant efficiencies are not included in the scope of this report. However, it is interesting to note how much more efficient these plants can be. For example, a plant with a fuel energy input of 500 GJ and an electrical output of 200 GJ has an efficiency of 40% (200/500). But if 150 GJ of waste heat is used, then the overall plant efficiency goes up to 70% (200+150/500). Alternatively, if the energy produced as heat is excluded then the apparent power generation efficiency is 57.1% (200/(500–150)). Conversely, the efficiency of heat production is 50% (150/(500–200)).

Although there is no standardised methodology for reporting plant efficiency, there are some common methods used in practice. For example, in Alberta, Canada, the plant efficiency is reported on a monthly basis and a year-to-date average. This efficiency is calculated from the energy generated by the plant (MWh) and the heat input (MJ). The heat input is calculated from the total mass of coal used (based on gravimetric coal feeder data) taking into account the HHV. The HHVs are measured on an 'as-received' basis from weekly coal samples taken directly from the coal conveyors and sent to an external laboratory for ultimate analysis.

In plants in Saskatchewan, Canada, the efficiency is determined using on-line performance calculation software which gathers data from sensors around the plant. Gross power metering systems determine the generated and exported power. The efficiency of the boiler itself is calculated on a empirical and thermal basis using exit gas temperatures, O_2 measurements, and unburnt carbon analysis.

The calculation of net efficiency, also called the 'components method', is used in Japan. This method uses the overall plant efficiency based on boiler efficiency (ηb) and turbine efficiency (ηt) while accounting for plant losses (CIAB, 2010). The equation for this is included in Appendix 1.

VDI 3986 is the German national standard for determining efficiencies of conventional power stations. The standard calls for any additional usable heat energy produced to be expressed in terms of the electrical power which it would have generated had it been used in the main power process (VDI, 2000). In practice, the fuel samples are collected and analysed to determine the fuel content based on the LHV. The data are certified by independent auditors and made available to the public. Individual plant data are not published. The plant efficiency is based on LHV input versus net electricity output (CIAB, 2010).

In the USA, the ASME (American Society of Mechanical Engineers, 1996) have published several standards for the measurement and calculation of power plant efficiencies. These include ASME PTC 46-1996, also known as the 'input-output' method. This methodology relates to the measurement of a plant performance during normal operating conditions and requires the following:
- a means to determine (directly or indirectly) all of the heat inputs and all of the electrical power and secondary outputs;
- a means to determine (directly or indirectly) the parameters required to correct the results to the base reference condition;
- test result uncertainties within the required limits.

For the component method, ASME PTC 4.1-1964 is the methodology given for determining the thermal efficiencies of boilers, based on fuel properties and boiler operation. There is an online tool to calculate this directly from input data: http://www.exoeng.com/becalc.htm. This ASME method describes two different ways to calculate boiler efficiency (Keir, 2011):

- the input-output method (also known as the direct method). This approach uses coal mass flow and analysis such as calorific value. The coal mass flow is multiplied by the CV to give the total heat input which is then divided into the measure heat output. However, determining coal mass flow accurately can be problematic at some plants, especially those using volumetric feeders rather than gravimetric feeders;
- the losses method (indirect method) is preferred at some plants and involves the subtraction of losses to the boiler from the total theoretical boiler efficiency.

Following this, ASME PTC 6-2004 is the method used to determine the thermal efficiency of steam turbines and is based on the measurements of actual turbine performance parameters. The results from these ASME methods can be used in various of the equations in Information Box 1 to calculate efficiency based on the required factors.

More information on national requirements for establishing plant efficiency are discussed in Chapter 6.

2.3 Plant and furnace diagnostics

As discussed above, there are numerous ways to define and estimate the efficiency of a coal-fired plant based solely on the design specifications (the efficiency quoted at purchase) and on the input and output of the plant (fuel in, versus energy out). There are some parts of the plant performance which reduce efficiency but which are difficult to quantify, for example (CIAB, 2010):

- combustor flue gas wet and dry gas losses and unburnt gas heating value;
- frictional losses, radiated and convected heat;
- off-load losses associated with start-up and shut-down;
- transformer losses.

Over and above this, plant efficiencies reflect not only the theoretical design efficiency but also actual operating efficiencies. This means that identical plants, or even the same plant tested twice, can give different results. This is due to factors such as (CIAB, 2010):

- the use of different assessment procedures and standards;
- the use of different plant boundaries and boundary conditions;
- the implementation of different assumptions or agreed values within the scope of the test standard;
- the use of different operating conditions during tests;
- the use of correction factors to normalise tests results before reporting;
- the expression of results on different bases (such as gross or net inputs and outputs);
- different methods and reference temperatures for determination of fuel calorific value;
- the application of measurement tolerances to the reported figures;
- differences in the duration of assessments;
- differences in the timing of assessments within the normal repair and maintenance cycle;
- errors in measurement, data collection and processing;
- random performance and measurement effects.

However, it is possible to determine efficiency more accurately by monitoring the performance of each part of the plant in turn, using the component method. As mentioned in Section 2.2, the ASME has performance test codes for determining the performance of individual plant parts such as air heaters, engines, turbines, condensers and so on. These can all be found on the internet at http://www.normas.com/ASME/ASME-PTC.html.

According to Garwood and Jones (2008) most standards for determining and reporting plant efficiency, such as those published by the ASME, are specific to plant sub-components (such as heaters or turbines). They allow variations in methods and assumptions but usually relate to short periods of time rather than providing long-term energy efficiency evaluations.

Commercial systems are available which have been designed to monitor the performance of each part of the plant as part of routine plant performance and control. It is beyond the scope of this report to discuss these systems, as they have been covered in previous reports (Henderson, 2003; Nalbandian, 2005; Kessels, 2009). The interested reader is also referred to an article by Energy Edge (EE, 2010) for a directory of information on how to calculate the efficiency of the turbines and pumps involved in a complete power plant steam power cycle.

Another report by Adams (2009) reviewed the options and potential for coal-fired plants to improve efficiency to reduce GHG emissions. Diagnostic tools are used to check the performance of plant control and monitoring systems several times during the life of most plants in OECD countries. Adams (2009) describes supervisory systems, such as the Decision Suite being produced in Prague, which communicates with the plant control system in both directions and provides the plant management with information for optimal operational mode adjustment and recommendations for long-term plant operation. Modern instrumentation and control systems are designed to improve plant performance and, based on the results, modifications such as adjustments to steam pressure, condenser temperature and so on can be made.

Plant efficiency can be maximised by optimising boiler combustion which, in turn, is determined by the fuel:air ratio. Flue gas analysis of excess oxygen and/or CO provides data on the combustion efficiency and, based on results being analysed on a realtime basis, the plant can be tuned to operate at the best heat rate and lowest NO_2 (or NO) and CO_2 levels. The best operating points are reported to be at 1–4% excess air with 0–200 ppm CO (Simmers, 2010). Systems for monitoring CO, CO_2, O_2 and other major pollutants are discussed in more detail in Chapter 4. Higher CO_2% and lower O_2% in the flue gas are associated with higher boiler efficiencies. However, it is important to remember that total mass production (emissions) of CO_2 and NO decrease with the improvement of boiler efficiency.

The efficiency of coal combustion can also be determined in more simplistic terms by measuring the amount of unburnt carbon that is released from the flue gases. This determines whether the coal is being completely combusted in the furnace. There are commercial systems available for this kind of measurement, some of which are based on cross-duct measurement systems somewhat similar to those used for particulate monitoring (*see* Chapter 4). However, offline systems, which sample the particles in the flue gas and then analyse them separately for the unburnt carbon content, are reported to give more reliable results. These systems would not be used to determine the efficiency of the boiler but rather as diagnostic tools to determine when the furnace is working as it should. The results from furnace diagnostics can also help solve problems with several areas of plant performance, such as fouled burners, induced draft fan imbalances and coal fineness problem (Simmers, 2010) but these are not within the scope of this current report.

2.4 Benchmarking

There is currently no definitive standard for collecting, compiling and comparing coal-fired power plant efficiency. And, according to the Coal Industry Advisory Board (CIAB, 2010), defining a common methodology to rationalise efficiency reporting is not a practical proposition. The CIAB proposed that approximate corrections be used, requiring only limited information, since this would allow estimates to be obtained even when only limited data are available. The report argues that average figures, reported for periods of a month or more, will be inherently more reliable than design values, performance guarantees or short-term tests under ideal conditions since they reflect the actual efficiency achieved. This will include the effect of factors such as fuel moisture ash and sulphur contents, type of cooling system, ambient temperature and humidity, and the presence of pollution control technologies.

Although it would make sense for a standard approach to be determined for future use, this is not practical due to the many different reporting bases and assumptions already in use around the world (CIAB, 2010). During their survey of the most efficient plants currently in operation, the International Energy Agency (IEA, 2007) emphasised that the main problem with reported efficiencies was determining whether the values quoted had been obtained on an HHV or LHV basis. As described in Section 2.1, this can make a significant difference to the calculated efficiency values. The IEA report suggested that an internationally agreed efficiency basis, along with a clear statement of what calculation basis is used, would make comparisons between systems far more reliable. However, it can be argued that, for situations such as those in developing countries, the actual value of energy is arguably less important than the rate of improvement. For example, Seligsohn (2010) suggests that the best way to track the efficiency of power plants is to observe the trend rather than focus on current values and short-term results.

Perhaps one of the major issues with determining and comparing power plant efficiency is that this information is often considered confidential and commercially sensitive information by many plant operators (van de Marel and Bins, 2005). In order to avoid a direct comparison of data, the process of benchmarking has become popular. During the 2005 Gleneagles Summit, the G8 leaders requested a review and assessment of information on the energy efficiency of coal-fired power plants with the view that a clearer understanding of efficiency and how to benchmark performance would put policy makers in a better position to encourage improvements in plant performance (CIAB, 2010).

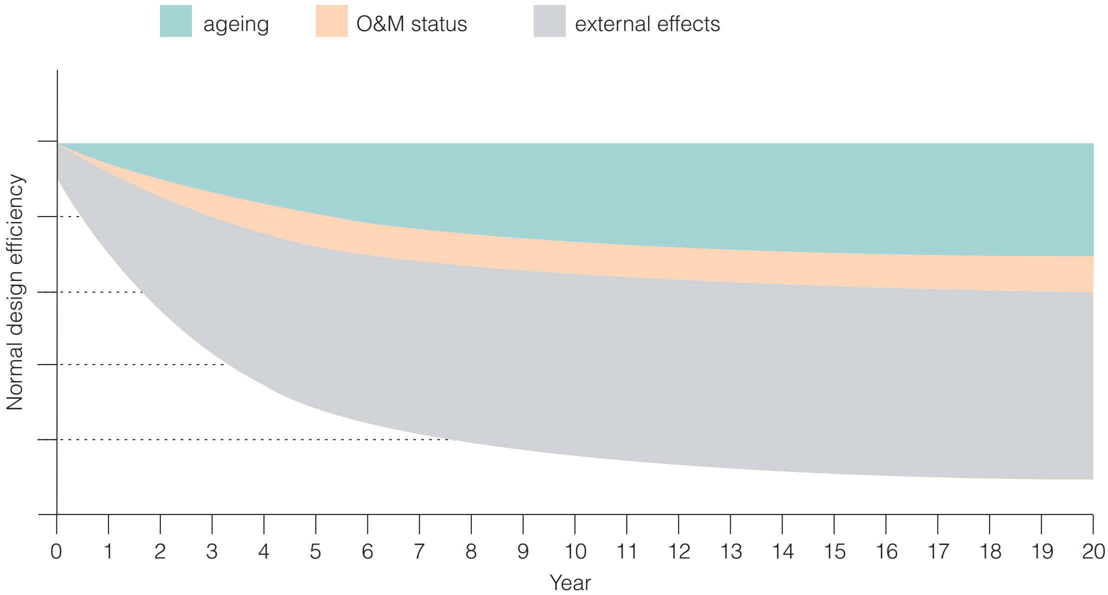

Figure 3 Effect of ageing, operation and maintenance status and external effects on normative design efficiency (van der Marel and Bins, 2005)

The process of benchmarking has been used quite extensively in The Netherlands. In 1999 the Dutch government agreed on an energy efficiency covenant as part of the country's climate change policy. The government agreed not to expose the benchmarking parties to additional energy taxes. As part of the benchmarking process, independent consultants were used to define the 'World's Top' (WT) performance on energy efficiency (top 10%) and then to evaluate the gap between each individual plant's performance at that of the WT. The evaluation was based on operational efficiencies, in TJ/y, and measured as the difference in specific energy consumption of the WT and the installation and the production volume of the installation (van der Marel and Bins, 2005).

When preparing the comparison, it was decided that, although design efficiency is not the best indicator of actual plant efficiency, it is a value which can be obtained without breaching any confidentiality or without a significant amount of evaluation of each of the plant-specific factors which affect the actual efficiency. The first round of benchmarking, in 2000, was therefore based on design efficiencies only. However, using the design efficiency can take plant age into account but does not allow correction for any improvements made to the plant which may skew results (van der Marel and Bins, 2005).

Van der Marel and Bins (2005) noted that, along with numerous external factors, there are three major factors that stop plants performing at their design efficiency – ageing, operation and maintenance practices. The basic effect of these factors on the normative design efficiency are summarised in Figure 3 The consultants tried to include these effects to estimate actual performance efficiency based on the design efficiency. Firstly, 'corrected operation efficiencies' (COE) for the benchmarking installations were calculated by adjusting the design efficiency for age effects. Secondly, the operational efficiencies for the Dutch plants were calculated from electricity production divided by fuel consumption and then corrected for external factors such as part load, ambient conditions and so on. The result of this was regarded as the COE for the Dutch plants. The COEs for the WT plants could therefore be compared directly with the COE for the Dutch plants. In order to make these corrections for age and external factors, the consultants had to investigate whether there were enough data available to produce valid correction factors. It was concluded that there were not enough data on the effects of operation and maintenance but that the effect would be relatively small anyway. The effects of ambient conditions and cooling water temperature were also found to be negligible. Corrections for running at partial load could be made by comparing the load with actual typical load profiles for the plant while running a base load, medium load and peak load. A fuel consumption correction of 0.5% was used for plant participating in the Dutch 'grid frequency control' system which requires changes in plant performance to keep the grid frequency within set limits. Perhaps the greatest factor was that of the inclusion of biomass in cofiring plants. The cofiring efficiency was calculated as a function of the calorific value of the biomass material.

Based on these data, the consultants were able to establish a basic benchmarking system to determine the performance of actual Dutch power plants against the top ten performing plants (WT) in the world. The results of the benchmarking process were used to determine CO_2 allocation in the Netherlands under the EU ETS (EU Emissions Trading Scheme) – installations with a high energy efficiency were allocated more allowances as a reward for early action (van der Marel and Bins, 2005).

Roukens (2004) argues that benchmarking systems such as that described above have only gained recognition in a few countries and that they are targeted at general operation and managerial information rather than at energy efficiency specifically. Roukens also emphasises that a level playing field is not possible due to large differences in the market, resource and infrastructure around the world. There can be a significant difference between how efficient a plant should be and how efficient it actually is when meeting local and regional demands.

2.5 Comments

At the moment plant performance and efficiency is determined at most plants primarily in order to ensure good operation – to maximise electricity output for the fuel used. There is, however, growing recognition that plant efficiency is one of the major factors determining the volume of emissions from the plant. Emissions of all pollutants, including CO_2, SO_2, NOx and trace elements, are directly related to the amount of fuel used. Therefore more efficient plants will burn less fuel and subsequently emit less pollutants. International and national legislation is beginning to evolve, to include emphasis on the reporting and improvement of plant efficiency in order to reduce all emissions simultaneously and to promote the efficient and sustainable use of natural resources such as coal.

Currently there are too many conflicting and overlapping methodologies available to estimate plant performance. This means that a fair and direct comparison between different units and plants is often not possible. Some operators will merely quote the design efficiency of their unit whereas others will use extensive measurements and calculations to provide a more accurate evaluation of efficiency based on the actual performance of the plant in practice. Even simple differences, such as the use of LHV or HHV to estimate efficiency, can cause major discrepancies in any performance comparison. Over and above this, many plants regard their efficiency data as commercially sensitive and refuse to publish data in a manner which could be used for such comparisons. However, it has been argued that a standard for the direct comparison of plant performance internationally is not necessary and that more general processes, such as benchmarking or the measurement of improvement in plant performance following repair or upgrade, are more useful with respect to encouraging operators to maximise their plant efficiency.

3 Measurement and estimation of emissions

Legislation to control emissions of atmospheric pollution has been established in different forms (APEC, 2008; Sloss, 2003):

- emission standards, limits or caps which set fixed limit values (such as g/m^3 or t/y) for a source or source type;
- emission performance standards, that incorporate output based controls linked to electricity production (such as g/GWh);
- technology standards which set requirements for BAT (Best Available Technique/Technology) or MACT (Maximum Achievable Control Technique/Technology);
- fines, taxes and levies, penalising sources based on total emissions;
- emissions trading;
- inventories reporting emissions from sources which exceed defined thresholds.

For most of the approaches, there is an inherent requirement to be able to determine the mass and/or volume of a pollutant being released from each source. There are several commonly used methods for determining emissions from sources such as coal combustion:

- emission factors;
- mass balance calculations;
- manual monitoring/stack testing methods;
- CEMs (continuous emissions monitoring systems; also referred to as AMS – automated monitoring systems – in the EU);
- PEMs (predictive emissions monitoring systems) systems.

The following sections review the most common methods for measuring or estimating the volume of pollutants in the flue gases of coal-fired power plants. In some situations, especially when determining emissions of CO_2 for emissions reporting or trading, emission factors are preferred. However, the monitoring of pollutants such as SO_2 and NOx has been required for several decades in most developed countries and so direct measurement systems available for monitoring are well established and considered as standard on most plants. Ackermann and Sundquist (2008) report that there is often disagreement between emission estimates produced from emission factors, and estimates obtained from CEM data. On average, CEM estimates for SO_2 emissions in the USA were 3% higher and NOx emissions 20% lower than those calculated from fuel data. Even greater variability (32% lower to 59% higher for SOx and 29% lower to 80% higher for NOx) were reported for data at the state level. There was 'even greater variability at the boiler level'. There are a number of reasons why these numbers do not match including potential variations in emission factor with load (especially NO), changing coal quality and assumptions based on actual densities of the gases measured (Keir, 2011). Some argue that the data from the CEM systems would be more accurate since these are based on actual measurements. However, regulated requirements often call for the use of emission factors. In Europe, North America and Japan, SO_2 and NOx are monitored on a continual basis using CEM systems. For other species which are more difficult to monitor in practice, such as trace elements, mass balance methods can be used. However, for CO_2 there appears to be a strong argument for the continued use of emission factors. The following sections discuss the different approaches available to quantify emissions.

3.1 Emission factors

An emission factor is a value which can be used to estimate emissions from a specific fuel and a specific source. Emission factors can be used to estimate emissions when direct monitoring is not possible. However, as will be discussed below, and in Chapter 5, there are some situations where emission factors are regarded as superior to direct emission measurements.

Emission factors are particularly useful for preparing emission inventories as they provide values which can be applied to models and spreadsheets to calculate emissions from a large number of sources without exhaustive testing at each plant. The emission factor approach was discussed in a previous report by Sloss (2009b). Emission factors are derived from previous monitoring and mass balance studies and are commonly organised into tables which allow the user to determine which emission factor is most appropriate for them to use. In many cases, plant-specific emission factors are produced from significant amounts of monitoring data at the plant in question. In some cases, emission factors are required instead of raw data for compliance purposes, such as for reporting total emissions over a certain period (hour, day, month or year) on sources which do not have appropriate monitoring systems in place. In such situations, emission values from sporadic manual stack tests can provide snap-shot values on emissions which can then be used to prepare plant-specific emission factors.

Although emission factors can be obtained from databases such as the US EPA's AP42, most operators prefer to use a plant-specific emission factor whenever possible. A report by Sloss (2009b) explained how emission measurements are used to produce and improve emission factors. For ease of understanding and consistency, the section from that report outlining the calculation of emission factors is given in Appendix 2.

In the past there has been no single, uniform approach used in preparing and using emission factors based on measurement of emissions on a site-specific basis. In an effort to co-ordinate a more standardised approach, the Comité Européan de Normalisation (CEN; European Standards Committee) and the International Standards Organisation (ISO) are finalising an international standard for estimating emission factors from mass emissions data.

Although the International Accounts Standards Board (IASB) has attempted to provide guidance towards a uniform standardised approach to the preparation and use of GHG emission factors, this has so far not resulted in any official single approach being used. However the IASB and the FASB (Financial Accounting Standards Board) were working together to examine the existing programmes and to produce a single standard, which was due to be published during 2010 (Fornaro and others, 2009).

Emission factors are often the method of choice for reporting GHG emissions due to the nature of the reduction targets and trading schemes in operation. Since CO_2 is an emission of particular global significance and is also a pollutant for which emission factors are commonly used, the remainder of this section will refer mostly to data on CO_2 emission factors. However, the main principles apply to emission factors that are used to estimate other emissions.

The emission factor (EF) method is the preferred method for obtaining data required under schemes such as the EU ETS (EU Emissions Trading Scheme). CO_2 emission are calculated as follows:

$$CO_2 = \text{activity data x EF x oxidation factor}$$

or

$$CO_2 = \text{fuel flow (t) x net calorific value (TJ/t) x EF (tCO}_2\text{/TJ) x oxidation factor}$$

Price and others (2002) reviewed the different CO_2 emission factors that have been used to estimate emissions from the electricity generating units by the California Climate Action Registry in California. Three methodologies were used:

- Public data sources – using data from the US EIA, historical data from power plant generation and fuel-consumption and so on;
- Elfin model – simulating plant operations and emissions based on data sets for six electricity utility service territories;
- Load duration curve methodology – based on more complex plant operation algorithms.

Placing the same basic data into the different methods produced results which were in general agreement, giving the total CO_2 emissions for California for 1999 as 29.0, 26.1 and 29.5 MtC respectively. However, closer analysis of the data indicated that the results from the different methodologies could differ quite significantly on more specific data such as seasonal changes in emission factors, where the difference between the results could be almost 20%. Price and others (2002) concluded that a hybrid methodology could give the best results.

A paper by Afsah and Aller (2010) discusses the often significant discrepancies in CO_2 emission estimates produced around the world by different organisations and different methodologies. They describe the current systems in us as 'inadequately standardised' and note that there is no way to verify results. They state that 'greater attention, standardisation, empirical testing and third party audit of estimation technologies is necessary to create a CO_2 emissions reporting infrastructure that is able to support verification of impacts from efforts to reduce overall CO_2 emissions at the national and global level.' Afsah and Aller (2010) provide much evidence to show major disagreements in emission estimates produced by different sources and provide a reminder of the drastic effects of the discovery of incorrect estimates in CO_2 emissions data on the EU ETS market in April 2006.

There are numerous different GHG calculation and estimation protocols and schemes published around the world. For example, in June 2009, the Climate Registry released a sector-specific protocol for the calculation, verification and reporting of GHG emissions from the electric power sector. The report can be downloaded from: http://www.theclimateregistry.org/resources/protocols/electric-power-sector-protocol/.

Although CEMs for SO_2 and NOx are common on coal-fired plants in the USA, the US EPA's Acid Rain Program and NOx Budget Trading Programs allow trading of SO_2 and NOx allowances and these values are calculated on annual and seasonal basis using emission factors and not cumulative CEM data.

3.2 Mass balance calculations

The mass balance approach for estimating flue gas pollutant emissions is useful for trace species such as mercury and other trace elements which may be a challenge to measure at the stack. By determining the amount of the element entering the plant via the coal and then measuring the amount of the element remaining in any effluents such as the fly ashes, the amount emitted can be calculated. This approach is included as an option for mercury measurement at some plants under the CWS for mercury (Canada-Wide Standard; *see* Chapter 5).

The general approach for mass balance estimation is as follows, taking mercury as an example (CCME, 2007):

- annual average of the coal mercury content is determined from all coal samples analysed for mercury (ppm or g/t) in a year;
- total coal burned in the year is determined from records (t/y);
- annual average mercury in coal is multiplied by total coal burn to obtain total input (g/y);
- annual average for the ash mercury content is determined from all ash samples analysed (ppm or g/t) in a year;
- total ash is determined (t/y);
- annual average mercury in ash is determined from the mercury content and the total volume of ash (g/t);
- the total mercury in the ash is subtracted from the total mercury in the coal to obtain estimated emissions from the stack;
- the total mercury in the residue is divided by the total mercury in the coal to obtain the capture rate.

3.3 Manual monitoring/stack measurements

Emission limit values (ELVs) define a set maximum limit on emissions of pollutants such as particulates, SO_2 and NOx. Measurement at the stack with a manual or automated device can then confirm whether or not this limit value has been exceeded. In most cases, monitoring of these major pollutants is performed with automated CEM systems (*see* Section 3.4). However, for more challenging species or species for which CEM systems have not been commercialised, such as most trace elements, manual systems are used. Manual systems are also used to calibrate CEM systems to ensure the measurements are correct and consistent over time.

During manual testing, a team of experts perform a one-off series of measurements to get a 'snap-shot' of the emissions. Obviously this is less than optimal with respect to providing assurance that emission limits are not being exceeded at any time over an extended period. However, it is often the case that, on a plant which runs in a very regular manner, with well quantified performance and fuel characteristics, a minimum number of manual monitoring campaigns can be enough to demonstrate that the emissions of a regulated pollutant are consistently well below the regulated emission limit value.

Manual monitoring methods are commonly defined within national and international standards. Most directives, such as the LCPD (Large Combustion Plant Directive) in the EU, specify a hierarchy of standards that must be used for monitoring emissions. In the EU this is:

CEN standards > ISO standards > National standards

The standards produced by CEN are prepared over an average of seven years through discussion with experts from all interested countries. Once approved and published, CEN standards are required to be used in all EU member states for any relevant monitoring under legislation monitoring regimes. ISO is the International Standards Organisation. ISO standards are produced in the same way as CEN standards but, once published, are considered more as recommendations or guidance on best practice than actual requirements.

The ISO and CEN standards relevant to monitoring emissions from coal-fired plants are listed in Appendix 3. These and other methods for measuring flue gas emissions are discussed in more detail in Chapter 4.

The measurement of flue gas emissions by manual measurements relies heavily upon the expertise of the stack testing team. The MCERTs scheme in England and Wales has been expanded to include certification of personnel and companies based on minimum qualifications and appropriate grading. Following the lead of the MCERTS scheme, the USA has been working for a number of years to develop a scheme similar to MCERTS for accrediting the staff involved in emissions measurements. After 2012, all source testing at large regulated sources such as coal-fired plants must be performed by organisations complying with the ASTM D7036 standard – 'Standard practice for competence of air emission testing bodies'. The standard includes requirements for the creation and maintenance of a comprehensive quality management system, document control, training and certification for qualified individuals, operating procedures, procurement, reporting and so on. At the moment the only independent body for the ASTM D7036 standard is the Source Testing Accreditation Council (STAC). More details on the scheme at the work of STAC can be found at: http://www.betterdata.org/.

3.4 CEMs

The majority of large coal-fired plants in developed regions such as North America and the EU have CEM systems installed to continuously monitor emissions of particulates, SO_2 and NOx in a continuous, real-time manner. Figure 4 shows the standard system for monitoring emissions

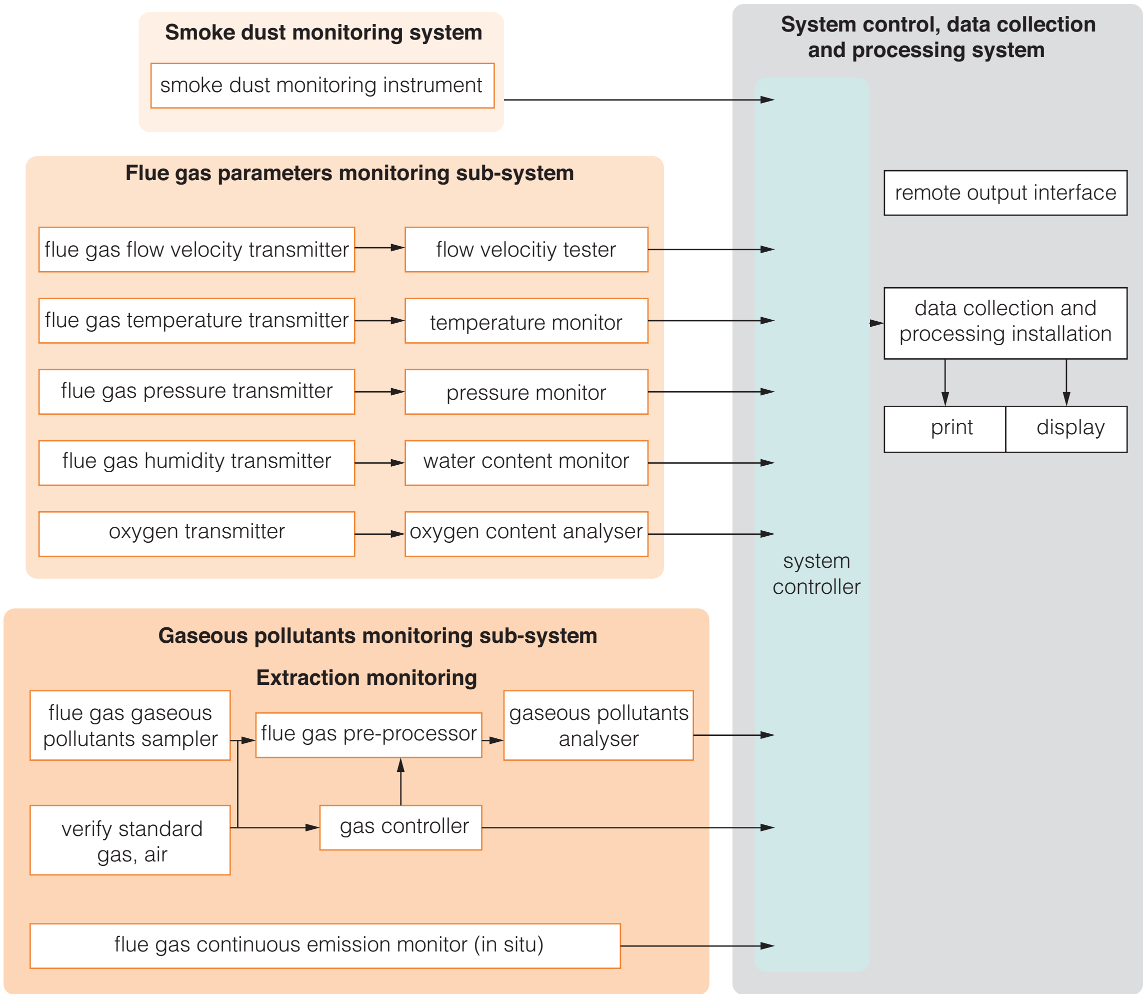

Figure 4 Continuous emission monitoring system for tracking flue gas (APEC, 2008)

(APEC, 2008). Along with the specific analysis systems for the measurement of the major pollutants, CEMs may also include or be accompanied by systems which measure other factors which are required to determine the actual emissions of pollutants in whatever format is required. This may be as total mass emission over time (such as g/h or t/y), mass emission per volume (such as ppm, or mg/m^3) or even mass per energy produced (such as t/GWh). For this, CEMs must include standard components such as:

- flow rate monitors;
- probes and umbilical lines (to capture the sample from the stack and deliver it to the monitor);
- conditioning equipment (such as heaters, condensers, dilution systems);
- data loggers;
- DAHS (data acquisition and handling systems) to record all measurements and automatically calculate and record emissions and heat input in the required units.

CEM systems come in several distinct forms (Sloss, 1997):

- In situ systems – which are placed inside the stack or flue to measure pollutants directly. CEMs for O_2 monitoring and opacity (a proxy measurement for particulate concentration) are the only common in situ CEM systems. Cross-duct monitors, are in situ systems which involve a beam across the stack to measure gas components as they pass. Cross-duct CEMs are difficult to calibrate and do not cope well with high humidity flues such as those encountered downstream from flue gas desulphurisation (FGD) systems. Insertion probes are used as approximate cross-stack samplers – probes mounted in the duct provide small optical paths which are 10% or less of the duct diameter;

- Extractive systems – where the sample is withdrawn from the flue and analysis is performed elsewhere. These systems avoid the need to place expensive and sensitive equipment into the hot and often acidic flue gases at a power plant. However, the sample must be withdrawn via a sampling/umbilical tube to the analyser and, unless the conditions are well controlled, there is the possibility of condensation, artefact formation or sample loss.

CEM systems are subject to rigorous quality control requirements. In the EU, the Technischer Überwachungsverein (TÜV; Technical Inspection Association in Germany) evaluates and certifies CEM systems, and only those systems which have been certified should be used for compliance monitoring. CEM systems which are not certified must undergo rigorous testing to demonstrate equivalency to a certified CEM system or standard methodology. In the UK the Environment Agency (UKEA) has established the MCERTS (monitoring certification) scheme which is similar to and equivalent to the TÜV system, so that a system certified by MCERTS is automatically TÜV certified and vice versa. The European Standards Committee, CEN, has merged these into standards EN 15267 parts 1-3, listed in Appendix 3, which define the requirements for the certification of any new commercial CEM system. CEMs in the USA must also be certified or must pass through an evaluation process to demonstrate that they are as fit-for-purpose as a certified system.

CEM systems can be relatively costly (thousands of pounds to several thousands of pounds, depending on complexity). For example, a CEM system for SO_2 or NOx costs around £100 k. CEMs also require regular maintenance by qualified staff. Regular calibration and quality control can add hundreds of thousands of pounds more in annual running costs (£10–30 k annually for the average SO_2 or NOx CEM system). Annual compliance tests will add a further £5–15 k per year. However, in addition to acting as compliance monitoring systems, CEMs can also act as early warning devices to highlight changes in plant performance which can save the plant on repair and maintenance costs, if the data are used appropriately (Sloss, 2009b).

Although, theoretically, the data from CEM systems could be added together over time to give total emissions from a source, this is rarely how the data are handled. Instead, the data from the CEM system measurements are used mainly to flag any periods when the emissions exceeded any legislated emission limits. However, during representative periods, CEM data are collected and used to produce source-specific emission factors. This means that emissions can be estimated for periods where CEM data are invalid such as during start-up and shut-down (SUSD) periods, when the CEM is offline, or when emissions are above or below the CEM calibration range. Each plant should have its own protocol for CEM operation, often specified within the plant operating permit (AG, 2008).

3.5 PEMs

Predictive emissions monitors (PEMs) are usually cheaper than CEMs. PEMs predict a unit's emissions based on process variables. These prediction systems can be relatively simple, linking emission factors to process parameters that have a known relationship to emissions, or they can be complex neural network based models. PEMs are still regarded as being somewhat developmental, although they have been used at many plants in the USA where the plant performance is stable and well characterised. The US EPA is developing a protocol for the use of PEMs for NOx compliance determination (APEC, 2008).

Australia also allows the use of PEMs in some of its inventory requirements under local state licensing agreements. For the PEMs data to be valid, the following steps must be completed (APEC, 2008):
- the PEM must fully reflect the full range of operating conditions and emissions likely to be experienced during the licence period;
- the PEM's certification, including a description of the programme and copies of data obtained, must be lodged with the local EPA;
- this information must be supported by documentation on the pollutants, the source activity and the maximum error ranges of the PEM system;

- if the error range is greater than 10%, this error range must be added to the load values calculated (in order to ensure that underestimation does not occur).

3.6 Comments

In simplistic terms, there are two ways of determining pollutant emissions from coal-fired power stations – to estimate emissions based on previous accumulated and averaged emissions data (emission factors) or to actually measure emissions as they are emitted. However, in practice, one option is rarely used without some reliance on the other. Estimates of emissions for inventories or emission totals over extended periods of time are commonly prepared from emission factors. But emission factors are, in turn, based on data obtained from actual measurement studies. The best emission factors are those which are prepared from plant-specific data, obtained from each plant individually. Conversely, data from flue gas measurement systems are often regarded as too complex or detailed to be used in a cumulative manner to calculate total emissions over times and so emission factors are used instead.

CEM data are most useful as a means of determining, in a real-time manner, whether a plant is fully in compliance with emission limit values. However, when CEM systems fail, the plant must go back to relying on emission factors from previous data to calculate whether the plant remained in compliance during this offline period. And so both emission factors and actual flue gas measurement studies or CEMs are relevant and intrinsic for power plants to remain in compliance with all reporting requirements.

4 Monitoring of flue gases

As mentioned in Chapter 1, there are standard reference methods for monitoring major pollutants. These are designed according to basic empirical principles such as wet chemical reactions or spectral absorption of certain species. However, how these principles are applied in practice can vary from system to system and also from country to country, according to which methodology is defined as the national standard. Chapter 5 discusses the different international and national approaches. The sections below concentrate only on the principles of the different methods used for the measurement of different pollutants species. Appendix 3 lists the standard CEN and ISO methods for monitoring flue gases that will be discussed throughout this Chapter.

However, before discussing how to measure species such as CO_2, SO_2 and NOx, it is important to consider the other parameters which must also be measured in order to calculate total emissions from a coal-fired plant. These include the volumes of gas, temperature, pressure and moisture content.

4.1 Gas characteristics

Measuring emissions of a target pollutant gives only one piece of information. More information is required for the results to be expressed in terms of actual emissions (volume, rate and so on). It is normally the case that reporting regulations require that emissions data are reported in a specified format, such as mg/m^3 at standard temperature and pressure. The major parameters required for this are summarised in the sections below. It is important that the basis for reporting are made clear so that any discrepancies are obvious before direct comparisons are made. Some plants report at 'normal' conditions (0°C and 101.32 kPa) or actual plant temperature and pressure whereas others use 'standard' conditions. The latter can be confusing as the USA uses 15°C as standard whereas others can assume that standard means 0°C (Keir, 2011).

4.1.1 Flow rate

The measurement of flow (flue gas velocity) is necessary to determine the volume/rate of flue gas emissions in order to calculate the emission rate of any measured pollutant. Flow rate is actually relatively difficult to establish for stacks, especially large stacks where the flow rate may differ across the stack due to interferences such as bends or intrusions in the stack wall. Most plants have permanent flow monitors installed. The accuracy of flow monitors is highly important as the flow value will be used to determine the emission rate of any measurement pollutants. The emission rate will then determine whether the emission is over or under any specified limit. Any error in the flow rate measurement could lead to a significant under or overestimation of actual total emissions over time. To ensure that this does not happen, double checks can be used to confirm initial stack readings and important factors such as draught fan flow are taken into account (Keir, 2011).

Flow meters are commonly based on pitot tubes – measurement units designed to gauge the pressure drop of the flue gas as it enters a hole in a tube of established size and volume. The pressure drop is a function of the flow velocity. However, pitot tubes must be calibrated against the flow to establish the mathematical relationship between the pressure drop and the flow rate. Since calibration in a real stack is problematic, pitots are often calibrated in standardised conditions. Actual flows may deviate appreciably from the calibration conditions leading to inaccurate flow measurements (Botts, 2006).

Averaging pitot tubes, or annubars, are pitot tubes which take multiple samples across a section of pipe to average the differential pressure and to account for variations in flow across the section of pipe. Annubars can be prone to problems with blockage in pipes with high dust levels. Insertion type mass flow sensors can be cheaper options. These systems are based on velocity sensors which, in turn, are based on temperature measurements – the energy required to maintain a constant temperature difference between the internal sensor and the sample sensor relates to the mass of the gas flowing past the sensor. Advanced flow sensors can be used at high temperatures in or near the combustion zone and can provide diagnostic information which can be used to improve plant performance and efficiency (Bogue, 2010).

ISO method 14164 defines the automated methods which can be used for flow measurement (*see* Appendix 3). In the USA, Methods 2F, 2G, 2H and CTM-041 are similar standards which relate to the measurement of volumetric flow rate. Methods 2F and 2G deal with angular (non-axial) flow, 2H with circular stacks and CTM-041 for rectangular stacks and ducts (US EPA, 2009). ISO is currently working to establish an international standard for velocity and volumetric flow measurement in stacks both for manual and automated systems.

4.1.2 Moisture/H_2O

Water vapour is important with respect to cross-interferences with some in-situ monitoring systems. Many systems are therefore designed to remove water prior to analysis. This is often based on a Peltier cooling system or a membrane based drying system. However, under some regulations (such as the LCPD, Large Combustion Plant Directive, *see* Chapter 5), water vapour measurement is not required if the flue gases are analysed by extractive gas sampling and gas drying is used. However, even with gas drying, the moisture in the flue gas can remain at up to around 0.8% and this can still be enough to cause cross-interference with some systems (JEP, 2006a).

The water vapour concentration of flue gases must also be known in order to make a volume correction when calculating the dry gas composition for compliance purposes (approximately 6% moisture for unabated coal units and 12% for abated units with FGD). If a moisture measurement system is not available, correction can be made using default moisture values. These are (APEC, 2008):

	% moisture
anthracite	3.0
bituminous	6.0
subbituminous	8.0
lignite	11.0
wood	13.0

The CEM standard for the measurement of moisture is EN 14790, the condensation/absorption method. Water can be measured in the stack using NDIR or DOAS systems. If the flue gas sample is extracted for analysis then NDIR, FTIR and para-magnetic analysis can be used. If using the latter, the water value is obtained by calculating the difference between the wet and dry O_2 values. However, this approach is not generally suitable for use at coal-fired plants due to the low level of moisture (JEP, 2006a).

4.1.3 Temperature and pressure

Conventional unshielded thermocouples can be used on most coal-fired power unit stacks as the temperature (<150°C) is low enough to avoid any problems with radiative heat loss to the duct walls. However, many plants have corrosive flue gases and so the thermocouples must be covered with sheath materials for protection (JEP, 2006a)

The pressure inside the stack can be measured using conventional electronic pressure transducers. Information on stack pressure can be important for measuring in situ particulate concentrations (JEP, 2006a).

4.1.4 O_2

The CEN standard for the measurement of oxygen is EN 14789 (*see* Appendix 3) based on paramagnetism. Zirconium oxide sensors, based on electrochemical reactions, are the most common automated CEMs for measuring O_2 in combustion systems and such systems can be mounted on the end of probes and inserted into boilers to monitor combustion gases in situ. Several monitors in the same boiler give a representative group of measurements across the boiler. The sensors measure oxygen in a fuel cell oxygen analyser which gives results as a direct millivolt signal. The sensors can be calibrated online and in place and are therefore relatively simple to operate and maintain (Simmers, 2010). However, there are reports that zirconium oxide sensors cannot be used on a continuous basis at some coal-fired plants (Keir, 2011).

Tunable diode lasers (TDL) can also be used for O_2 monitoring and are commonly used in a line-of-sight position across the duct. However, true calibration of these systems is not possible and they are not certified by the US EPA for compliance purposes (Simmers, 2010). In situations where a sample gas is extracted from the duct, O_2 can be measured with a para-magnetic analyser or by electrochemical means (JEP, 2006a).

4.2 Major emissions

Following sections summarise the most common methods for measuring the major emissions at coal-fired power plants. These systems are well established and commercialised and are considered standard on most plants in developed countries.

4.2.1 CO_2

As with major pollutants, there are two main forms of determining and reporting CO_2 emissions:
- emission factors (as discussed in Section 3.1 and also in Chapter 5). GHG emission factors for coal, especially CO_2, were discussed in detail in a previous report by Adams (2008);
- direct measurement (using manual methods or CEM systems, as discussed below).

It would seem that there is a significant disagreement between the EU and North America on which of these approaches gives the most accurate or reliable results. As will be discussed in more detail below, the EU ETS (EU Emissions Trading Scheme) recommends the use of emission factors unless the data from CEM systems can be demonstrated to be more accurate. The IPCC (Intergovernmental Panel on Climate Change) Good Practice Guidance and Uncertainty Management of National Inventories also argues that CEMs cannot be justified for CO_2 alone because of the comparatively high costs and because CEMs do not necessarily improve accuracy for CO_2 estimation from fuel combustion (Herold, 2003). Conversely, in the USA, CEM systems are preferred for CO_2 monitoring. However, Fott (2002) argues in favour of the EU approach suggesting that, even though the direct monitoring of CO_2 enables automatic registration of emissions, the data based on the amount of fuel combusted (the emission factor method) 'seems to be more reliable'.

Commercial CO_2 CEM systems commonly work by either thermal conductivity (for 'high' concentrations of CO_2) or IR (infrared) spectrometry. ISO is currently working on a new two-part standard for GHG monitoring at stationary sources. Part 1 of ISO 14385 will deal with the calibration of CEM systems for GHG whereas Part 2 will deal with quality control. These standards are based on performance characteristics of GHG CEMs and do not specify the methodology used (Curtis, 2011, *see* Appendix 3).

There is a new CEN/ISO standard, still at draft stage, which aims to determine the proportion of CO_2 which comes from each fuel in coal and biomass cofiring systems. EN ISO 13833 'determination of the ratio of biomass (biogenic) and fossil-derived carbon dioxide – radiocarbon sampling and determination' is based on the distinction between the radioactive footprint differences between fossil carbon, in coal, and 'new' carbon in biomass fuels. The draft is due for completion late 2011/early 2012.

4.2.2 CO

CO can be measured using IR (infrared) spectroscopy. Although water and CO_2 also absorb IR, most commercial systems give a repeatability of ±5 ppm with low interference from these species. Systems can either be extractive, where the gas is withdrawn from the duct and cleaned before analysis, or can be line-of-sight systems which send the signal from the IR source on one side of the duct to the receiver on the other side of the duct. TDL can also be used for CO in the same way. For both systems the line-of-sight system provides an average value for CO across the duct whereas an extractive system can be positioned to withdraw samples from various points across the duct. However, the in-duct method can only be used in ducts and furnaces where the temperature is below 600°C and where the particulate concentration is not high enough to cause interference. Calibration of line-of-sight systems is a challenge as the duct cannot be filled with calibration gases. The US EPA does not certify line-of-sight monitors for compliance purposes (Simmers, 2010). The CEN standard for CO monitoring, EN 15058, is based on NDIR.

Another option is a dual-pass probe which directs IR through a hollow pipe to a mirror which then reflects the signal back for analysis. The pipe can be allowed to fill with flue gases from the desired location in the duct (Simmers, 2010).

4.2.3 Particulates/opacity

There are several ways of determining the particulate concentration of gas. These include methods to capture the particles and weigh them or systems which measure the amount of light obscured or reflected by the particles as this is proportional to the amount of particles present. The measurement of particulate concentrations using light reflectance, refractance, opacity or absorption has the disadvantage that the optical properties of particles at a source such as a coal-fired power plants may not remain constant over time. The calibration of optical systems is therefore critical to their accuracy. In South Africa, Eskom correlate the mA output of opacity monitors against the dust mass flow (Keir, 2011). In the USA, there is a requirement to determine opacity whereas in the EU either opacity or weight based/gravimetric methods can be used.

Opacity monitors measure the decrease in light intensity due to absorption and scattering by particles as the beam crosses the stack. However, other flue gas components may also interfere with opacity. Opacity systems can not be used after FGD units unless the flue gas has been heated well above the water dew point temperature. Those plants which have FGD installed also have the issue of lower particulate concentrations and therefore need more sensitive systems such as light scattering devices and often these systems are extractive to avoid the problems with high moisture and lower temperatures encountered in flue gases downstream of FGD systems. The sample gas must be heated to vapourise the moisture and then the gas is passed through a laser beam. The scattered light is then measured either on the other side of the sample gas (forward scatter systems) or back at the source of the beam (back-scatter systems) (JEP, 2006a). In the USA, plants with FGD units are exempt from opacity monitoring requirements.

Other optical based methods for particle monitoring include backscatter and flicker based systems. Alternative particle monitoring systems are based on the capture and weighing of the particles (gravimetric systems), tribolelectric systems (based on the charge passing from the particles to a probe in the stack) or beta-ray absorption devices, based on the changes in the transmission of β particles from a radioactive source in the presence of particles captured on a ticker-tape.

Since the particle distribution across the stack varies with flow and is affected by changes in pressure and any curvature or blockages in the stack, the positioning for stack sampling of particles is far more important than for gases. In the EU, the CEN standard for manual measurement of particulates or dust is EN 13284-1 – a gravimetric method. This is a weight-based method which requires the collection and quantification of the particles in a representative volume of gas. This standard includes strict guidelines on the choice of sampling location and specifies the position of multiple sampling points across large stacks**.** The standard then calls for sampling at each of these points to assess the average concentration across the duct and also to determine the most appropriate point for continuous monitoring, if this is required. The EU standard 13284-2 then gives details for the location of automated dust monitoring systems/CEMs. Any CEM systems to be used for particulate monitoring, must be calibrated against the standard gravimetric system or an acceptable alternative method.

The measurement of fine particulates/particulate matter (PM), PM_{10} and $PM_{2.5}$, is discussed in Section 4.3.4.

4.2.4 SO_2

SOx is the sum of both SO_3 and SO_2, reported as SO_2. CEM systems for SO_2 are common on most combustion plants in regions such as the EU, USA and Japan. CEM systems measure only SO_2 but can account for SO_3 emissions by use of a calibration factor.

SO_2 can be measured in situ with NDIR (non-dispersive infrared), NDUV (non-dispersive ultra violet) and DOAS (differential optical absorption spectroscopy). In situations where cross-stack measurement is not possible, SO_2 can also be measured by extracting the flue gas and using NDIR, NDUV, electrochemical cell devices, FTIR (Fourier Transform infrared spectroscopy) or UV fluorescence. However, it has been suggested that FTIR is not robust enough as a technology to cope with power station applications (JEP, 2006a). The electrochemical cell devices are commonly used for manual cross-checking of systems but, although CEMs based on electrochemical cells are also available, these are not currently used on coal-fired plants due to the challenging conditions (JEP, 2006a).

As listed in Appendix 3, the CEN standard required for monitoring SO_2 under EU directives such as the LCPD, is EN 14791 'Determination of mass concentration of sulphur dioxide – reference method'. Any CEM systems to be used for SO_2 monitoring, must be calibrated against this standard or an alternative method. The method is based on drawing the filtered sample through hydrogen peroxide absorber solutions for a specified time and at a controlled flow rate. The SO_2 in the sampled gas is absorbed and oxidised to sulphate ion. The mass concentration of sulphate in the absorption solutions is subsequently determined using ion chromatography or by titration with a barium perchlorate solution using Thorin as indicator. SO_3 is also absorbed and transformed into the sulphate ion and is therefore an interferent.

4.2.5 NOx

Similarly to SO_2, NOx can be measured directly in the stack using NDIR, NDUV and DOAS. If the sample must be extracted then the options are NDIR, NDUV, chemiluminescence, electrochemical cell devices or extractive FTIR. As shown in Appendix 3, the CEN standard for manual NOx measurement is based on chemiluminescence. Any alternative method or CEM system used must be calibrated against this reference method. Other national standards, such as the Australian Method AS3580.5.1, are also based on the chemiluminescence method (APEC, 2008).

NOx comprises both nitric oxide (NO) and nitrogen dioxide (NO_2) and NOx are commonly measured using CEM systems. Some monitoring systems can convert NO_2 to NO so that total NOx is measured.

However, NO_2 in flue gases is generally low (<5%) and so only NO is monitored. The NO_2 can be included either by using a correction factor or through the NO analyser calibration function. If a correction factor is used, NOx is usually expressed as NO_2 by converting NO to NO_2 mass equivalent by multiplying by 46/30 (Eurelectric, 2008). Chemiluminescence detectors detect NO by reacting it with ozone to give NO_2. The NO_2 produced is in an electronically excited state and emits light as it returns to the unexcited state. The emitted light is therefore proportional to the original NO concentration. To detect NO_2, the system must convert the existing NO_2 to NO. The total NOx can then be calculated. The ISO standard for NOx CEMs, ISO 10489, mentioned above, defines the requirements to ensure that any cross-interference from CO_2 and water, which can also react to chemiluminescence, is taken into account (JEP, 2006a).

For legislation such as the LCPD, total NOx has to be expressed as NO_2 for compliance purposes. This requirement arose from air quality requirements, since NO is oxidised relatively rapidly in the atmosphere to form NO_2. In most conventional coal-fired plants NO comprises well over 95% of the NOx and the remaining <5% is NO_2. N_2O is generally negligible in conventional systems. Although the NO_2 in the stack gas is generally low, some plants still choose to monitor this and use a catalytic convertor to allow total measurement, as discussed above (JEP, 2006a).

ISO 10849 allows the calculation of the total NOx based on NO measurement and the assumption that NO_2 accounts for 5% of the total emissions.

4.3 Minor and trace pollutants

The importance of trace pollutants such as mercury and fine particulates is increasing on the international agenda and so methods and commercial systems for monitoring these species are being developed.

4.3.1 Halogens

CEN standard EN 1911 defines the wet chemistry method for the measurement of HCl. ISO 15713 is the method for measuring fluoride. Both methods are wet chemistry methods which draw the stack gases through a series of impinger solutions. Hydrogen halides are solubilised in the acid (sulphuric) impingers whereas halogen gases are captured in an alkali solution. Because the gases have to be withdrawn and passed through a series of impingers, the system is not truly isokinetic – that is, it does not capture the gases at exactly the correct flue gas flow rate and therefore the accuracy of the system is not ideal. CEM systems are also available but are reportedly potentially prone to condensation issues.

4.3.2 Trace elements

CEN 14385 is the European standard for the measurement of As, Cd, Cr, Co, Cu, Mn, Ni, Pb, Sb, Tl, and V. US EPA Method 29 is the comparable multi-element sampling train used in the USA. Method 29 is a multi-impinger train which uses nitric acid to capture most gaseous metals and potassium permanganate in sulphuric acid to capture mercury.

CEN 13211 defines the standard wet chemical method for measuring mercury whereas EN 14884 is the standard for mercury CEMs. US EPA Method 29, as mentioned above, is also the standard US wet chemical method for mercury. Most mercury CEMs are based on atomic fluorescence. Mercury CEMs are required to measure mercury in often extremely low concentrations (<1.0 $\mu g/m^3$) in flue gases which contain other chemical species which cause interference and reactivity with the systems used in the monitors. Further, since mercury is present in two chemical forms in flue gas – oxidised and elemental, each with its own measurement challenges – the monitors must perform dual monitoring. Mercury CEMs are therefore significantly more complex than CEMs for species such as SO_2 and NOx. Mercury CEMs have improved significantly over the years and, in practice, are reported to have well over 80% availability. In the USA, mercury CEMs equipment and training typically cost around $200,000 and site preparation adds another £200,000–300,000 to the total cost. Once installed, the system may require up to 20,000 $/y in labour, 65,000 $/y in QA/QC, reporting, parts and material). However, in the long-term, the annual running costs of mercury CEMs are likely to become similar to those for SO_2 and NOx. Mercury CEMs are installed at over 600 power plants in the USA. The major mercury CEM suppliers in the USA are ThermoFischer Scientific and Tekran Instruments (NESCAUM, 2010).

The Thermofischer Scientific CEM is based on an extractive sampling system delivering the flue gas to a cold vapour atomic fluorescence (CVAF) analyser. The flue gas is withdrawn from the stack and diluted with nitrogen at a 40:1 ratio with air or nitrogen. A converter (unspecified type) within the system then converts all the oxidised mercury into elemental mercury since the CVAF analyser can only measure mercury in the elemental form. In order to perform speciation, two measurements must be taken – one with the converter involved, to provide data on total mercury, and one with the converter bypassed, to provide data on elemental mercury alone. The concentration of oxidised mercury is then calculated by subtraction. For the purpose of compliance monitoring in the USA, only the value for total mercury is required (NESCAUM, 2010).

The Tekran Instrument CEM uses a 30:1 dilution ratio for the stack gases and conditions the sample gas in a somewhat different manner to the Thermofischer system. The converter is pyritic. Interfering gases are scrubbed from the flue gas before it reaches the analyser. Similarly to the Thermofischer system, speciation of mercury is possible due to dual sampling of total mercury and elemental mercury alone. The Tekran system differs from the Thermofischer system in that it uses gold amalgam to concentrate the mercury prior to analysis (NESCAUM, 2010).

In the UK, PS Analytical market the Sir Galahad monitor which is similar to the Tekran system. Cemtrex and Ohio Lumex provide mercury CEMs which are based on AAS (atomic absorption spectroscopy) (NESCAUM, 2010).

Because the continuous monitoring of mercury is more of a challenge than the monitoring of species such as SO_2 and NOx, mercury monitors are more prone to operational problems and breakdowns. These include failure of the umbilical (heated sampling tube system), and failed system integrity tests. The NESCAUM (2010) report gives more detail on the operating experience with mercury CEMs in the USA and with specific challenges and problems that have arisen. The interested reader is referred to this document for further detail.

An alternative to CEM systems for mercury is the use of sorbent traps. Sorbent traps collect cumulated emissions of mercury from a stack over a period of time – hours, days or even weeks. The traps are then analysed for mercury content and the emission rate or concentration is calculated using information on the total flue gas flow over the sampling period. Although this method is not truly continuous, the results represent a valid average of emissions over the sampling period. US EPA Method 30B (which replaces the method previously known as Appendix K) is based on paired sorbent traps which are inserted into the stack for a suitable period of time (determined by the predicted concentration of mercury in the stack). The time period is a minimum of 30 minutes and three test sets are carried out. The sorbent allows speciation analysis. The QA/QC (quality assurance and quality control) requirements include agreement between the paired trains and spike recovery.

Since the methods used for mercury monitoring are either expensive or relatively challenging, the US EPA has developed a mercury monitoring tool-kit for simple, one-off measurements in challenging situations. The tool kit has already been used on coal-fired units in South Africa and Russia. The kit is a mobile laboratory which comprises equipment and guidance documents. The kit includes sorbent traps, sampling probes, flow meters, a direct combustion system to analyse mercury in solid samples and other auxiliary equipment. The system has the facilities to analyse coal, ash, flue gas and waste from the pollution control devices and can therefore provide a simple mass balance through the plant. The samples can be analysed and validated on site (Forte, 2011). The system is based on US EPA Method 30B, as described above.

At the moment there is no ISO or CEN standard specifically for measuring selenium emissions from stationary sources. However, a new work item has been opened up on this issue by ISO in 2011 which would suggest that there is growing interest in this element.

4.3.3 Organic compounds

A previous report by Sloss (2001) discussed emissions of organic compounds from coal utilisation and how they are monitored. ISO standard 11338 Parts 1–3 (*see* Appendix 3) define the different stages in sampling, cleaning and analysis for PAH (polycyclic aromatic hydrocarbons). EN 1948 Parts 1–3 define similar stages for the sampling and analysis of dioxins (PCDD, polychlorinated dibenzo dioxins) and furans (PCDF, polychlorinated dibenzo furans).

The sampling and analysis of organic compounds at coal-fired power stations is a particular challenge for several reasons:
- the concentrations of organic species in flue gases from efficient coal-fired power plants are low, often at or below the detection limit;
- the organic compounds are often reactive and therefore have to be sampled in such a way as to maintain the sample in a stable form long enough to transfer it to the analysis system;
- since there are often a large number of different and complex organic species present, the analysis methods and systems used are often relatively complex systems such as mass spectrometry and gas chromatography.

The measurement of organic species does not appear to be required on a continual basis at coal-fired plants anywhere but may be included in plant permits on a regular but infrequent basis. In such cases, manual systems can be used. CEMs for organic compounds are not common on coal-fired systems.

4.3.4 Fine particulates

Measurement of PM_{10} (and also $PM_{2.5}$) from sources such as coal-fired power plants is a challenge. These species exist in both primary and secondary particulate forms. Some are present in the flue gases as primary particles, whilst others are present as gaseous species which will form secondary particles as the flue gas undergoes cooling and mixing with the ambient air. This means that these species must be measured by different techniques – filtration or impaction methods for primary particles and condensation methods for the secondary particles. These issues are discussed in more details in a separate report by Sloss (1998). The science of fine particulate monitoring is complex and, even over a decade later, there are still disagreements over the best methods for monitoring these species. However, ISO have been working to produce several standards for fine particulate monitoring, as listed in Appendix 3. These methods are based on impactor systems which use changes in direction of gas flow to impact particles on a series of surfaces according to size and weight.

The US EPA has been studying modifications to improve the performance of its US EPA standard methods 201A and 202 for monitoring fine particulates. Method 201A is based on the use of either cyclones or impactors, but has been modified to include potential quantification of $PM_{2.5}$ as well as PM_{10}. Method 202, based on the condensation of gaseous $PM_{10/2.5}$ precursors, has been modified to limit any errors from the formation of SO_2 artefact – a situation where it has been argued that SO_2 may be measured as a particulate in the sampling system whereas it may not have become particulate in the real flue gas. The final methods are still undergoing editing and are likely to be published during 2011. One of the changes to Method 201A is the switch from the use of hexane from $MeCl_2$ following complaints that $MeCl_2$ is toxic and is prohibited at many sites in the USA.

CEM systems for PM_{10} are not considered applicable for measurements on coal-fired plants as yet. PM_{10} is therefore calculated as a ratio of the emission of total particulates, which can be measured continuously (as discussed in Section 4.2.3).

$$\text{Emission factor} = r(PM_{10}) \times PM \times SFV/1000$$

Where:

$$r\,(PM_{10}) = \text{the ratio of } PM_{10}/PM\text{, which is plant specific.}$$

PM is the concentration of particulates in dry flue gas at reference conditions obtained from CEM data where possible. If plants are known to have a significant proportion of PM as PM_{10} then this should be evaluated to give a plant-specific ratio. This ratio should then be applied to PM CEM data. Where this is not necessary, a default $r(PM_{10})$ can be applied to PM CEM data. If no CEM are available then an annual evaluation of PM with manual methods is performed and the $r(PM_{10})$ applied to this. For coal-fired plants without FGD an $r(PM_{10})$ of 0.8 can be assumed. Where an FGD system is present the $r(PM_{10})$ of 0.95 should be used.

4.4 Testing requirements

For the application of manual measurements and CEM systems discussed above, there are usually standardised approaches and requirements to ensure that the monitoring techniques are applied appropriately at the plant. These requirements are listed within any monitoring or measurement protocol or plan. The major considerations are summarised below.

4.4.1 Sampling location

Countries such as those in the EU and North America which have monitoring standards also have extensive guidance documents on how these systems should be located in flue gas ducts. There are important factors to take into account to ensure that the location allows the capture of a representative result. These include the requirement of a minimum distance between the sampling location and flow disturbances such as bends and branches (for example, in the UK it is recommended that automated systems are installed at least 2–5 diameters length of straight pipe downstream of any potential disturbance) (JEP, 2006a).

ISO 10396 standard: Sampling for the automated determination of gas concentrations, gives details for determining the best position for stack sampling. This includes the requirement to demonstrate that the sampling location is not subject to stratification (uneven distribution across the stack) and that the sampled gases are well mixed and homogenous. If the concentration for the pollutant being measured varies by less than 10% across the stack then a single point measurement is sufficient. However, if the variation exceeds 10% then the measurement system must either be relocated or multi-point sampling is required (JEP, 2006a).

The ISO 10396 is a general standard which helps determine the optimum location for any measurement system. However, individual standards, especially those for the measurement of particles, often also include details for determining the best location for sampling. For example, the EU standard for particulate monitoring (EN 13284-1, *see* Appendix 3) lists requirements which specify the maximum offset in gas flow, no recirculation, minimum flow velocity and so on. USA Method 1 also specifies sampling locations and conditions for general stack monitoring (JEP, 2006a).

Monitoring combustion gases accurately can be a challenge in large boilers with many burners (20 or more in a large boiler). Each of the burners can be considered a different process and the position of these can lead to stratification throughout the furnace. In these situations it is common for diagnostic analysers to be positioned in the 'back pass' of the furnace just ahead of or just after the economiser. To avoid any problems with continued stratification multiple probes are often used in an array across the duct and an average concentration is calculated. Tangentially-fired boilers do not experience as much stratification as wall-fired boilers (Simmers, 2010).

4.4.2 QA/QC

Most commercial CEM systems have their own requirements for calibration and maintenance. Over and above this, monitoring regimes such as those specified within the EU's LCPD specify minimum performance requirements for CEM systems. This includes minimum requirements for calibration and performance checks.

In the EU, CEN has set the standard EN 14181 for the Quality assurance of automated monitoring systems. EN 14181 is a relatively complex standard but can be simplified into its three major parts:
QAL1 ensuring that the equipment used is suitable and appropriate;
QAL2 setting up the equipment correctly at the source of emissions;
QAL3 ensuring that the CEM systems continue to work correctly.

Under QAL1, all new instruments must be certified under the MCERTs scheme (*see* Section 3.4) whilst existing instruments must be shown fit for purpose under QAL2. The calculated measurement uncertainty for the CEM system must be compared with the uncertainty requirements under the LCPD (20% for gases and 30% for dust) and must cover a range up to 2.4 times the ELV (emission limit value). The calibration ranges for SO_2 and NOx are also defined within the standard according to whether the plant is opted-in (must comply with an ELV) or opted-out (using <1% sulphur coal) (JEP, 2006a). The requirements for monitoring under the EU LCPD are discussed in more detail in Chapter 5.

Initial calibration and set-up of CEMs is defined under QAL2. The CEMs must be calibrated against a standard reference methods (SRM). The SRM methods for the major pollutants were discussed in

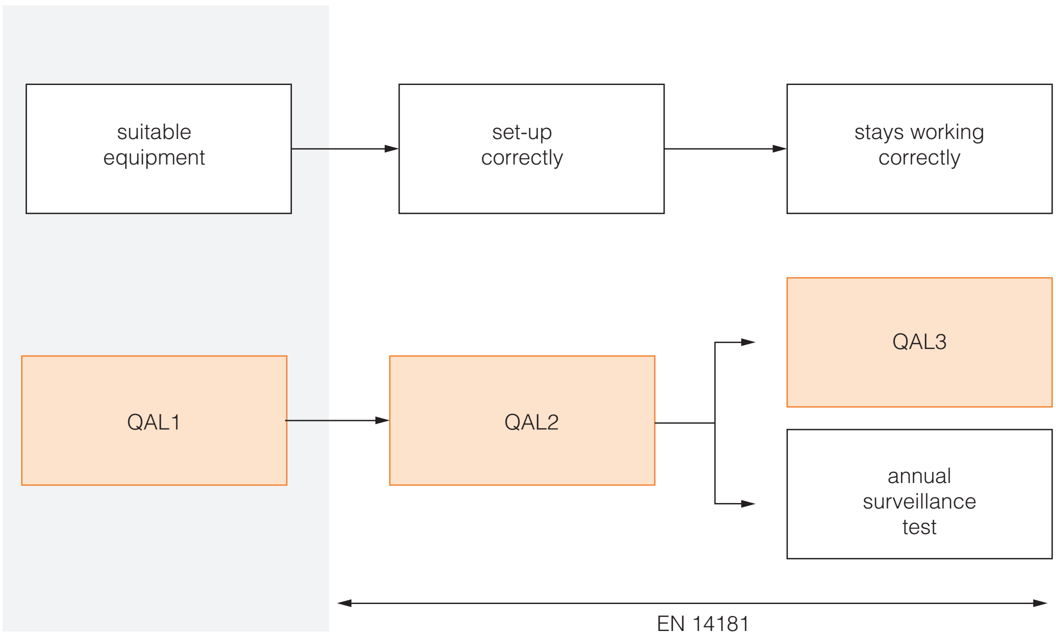

Figure 5 Simplified compliance flow chart for EN 14181 (Curtis, 2011)

Sections 4.2 and 4.3 This initial calibration requires at least 15 pairs of measurements over at least three days of operation. The operator must check weekly that all of the reported data fall within the range of the calibration. QAL2 is performed when an analyser is first installed and then at five-yearly intervals.

QAL3 requirements are designed to check the ongoing performance of the CEM system. This involves functionality checks which include checks on alignment and cleanliness, records, serviceability, leak tests, zero and span checks, drift checks, interferences, linearity and response time. A span check is used to determine the full-scale range of a CEM system, to determine the range of calibration gases required. Daily calibration checks are expressed as a percentage of the span value (US EPA, 2009).

EN 14181 is quite a complex standard and so the requirements are simplified in Figure 5. If there are any changes in plant performance or operation, such as a change in fuel or the installation of FGD, then the CEM system needs to be taken through QAL2 and 3 again to demonstrate that it is still fit for purpose.

4.5 Reporting requirements

The methods used to ensure that measurements are carried out correctly and the data handled appropriately are now recognised as being almost as important as the measurement methods themselves. CEN 15259 is the standard European method outlining requirements for determining a measurement plan objective, plan and report.

4.5.1 Units and standard conditions

CEMs commonly measure pollutant concentration in some direct physical or chemical means such as light absorbance or electrical conductance, depending on the basis of the measurement system. The instrument then converts these values into an equivalent concentration, based on the calibration of the system. Most systems in the EU report in mg/m^3. However, some instruments measure in ppm (measured molar concentration, parts per million by volume). This value for ppm can be converted into mg/m^3 as long as the molecular mass and the molar volume of the pollutant in question are taken into account. For SO_2, the ppm can be multiplied by 2.86 to give mg/m^3 and for NO_2 the factor is 2.05 (JEP, 2006a).

The decision on which approach for estimation/monitoring/measurement should be used, of those listed in the previous sections, is often defined within national legislation and/or within the operating permit of that plant. The legislation defines what needs to be measured and monitored, and when. It also defines the units and conditions for reporting. For example, the LCPD in the EU requires that all CEM data be reported in mg/m^3, where the volume unit is defined at 0°C and 1 standard atmosphere (1.01325 bar absolute). The concentrations must also be referenced to a specific oxygen concentration (6% by volume for coal plants) at dry stack conditions. As discussed in Section 4.1, EU standard EN 12039 for O_2, CO and CO_2 is commonly used alongside other methods to provide the values needed for normalisation of measurements to standard conditions (JEP, 2006a).

4.5.2 Missing data and other corrections

Part 75 of the CFR (Code of Federal Regulations) in the USA describes in detail the procedures for dealing with problems such as missing data. In monitoring regimes such as cap and trade programmes, sources are accountable for their emissions during each and every hour of unit operation. Data must therefore be reported for every hour ‘without exception’. On occasions when a CEM system fails, there are several ways to produce data for this period:

- a back-up monitoring system (not required at all plants in the USA);
- use of a reference test method (usually considered expensive and time consuming);
- use of an 'appropriate substitute data value'.

Part 75 of the CFR includes various Appendices on how best to produce this missing data. In most instances this requires the use of historical data which is most representative of the conditions at the time of the CEM break-down (US EPA, 2009).

Most CEM instruments have a detection limit below which concentrations of the target pollutants cannot be measured as distinct from the general background noise of the instrument. Normally if the concentration is below the detection limit then a zero emission should be reported. However, it is not uncommon for reporting requirements to require the values to be rounded upwards, and to use the detection limit as the assumed emission, or to use the highest value out of a given range to ensure that any risk to human health from pollution is not underestimated. This is less than ideal but when sources are numerous, non-detects can add up over a large area and could contribute to a significant underestimation of emissions.

During start-up and shut-down periods at combustion plants the emissions differ considerably from those when running under normal operation conditions. For species such as particulates, SOx and NOx there is a specific protocol which has been developed within the UK for use when reporting emissions to the LCPD. The methodologies are based on estimates of the amount of fuel burnt during start-up and shut-down (SUSD). This can be based on detailed calculations from measurements made during a number of SUSD periods (Eurelectric, 2008). CEM systems are often not appropriate for use during SUSD periods. This is because most CEM systems are calibrated to work most accurately within a pre-determined concentration range. This range would be set to be most accurate at the normal emission rate of the plant and not for any periods of unusually high or low concentrations which can occur at SUSD. Separate guidelines exist for estimating emissions during these periods (Weatherstone and Quick, 2009).

At times when empirical data are lacking, best guesses and estimates may be required based on expert judgement. In many cases, missing data is obtained by extrapolating representative data from the same source. In the absence of such data, emission factors are used. In such situations the assumptions and reasoning must be well documented and explained.

4.6 Comments

The measurement of pollutant species in the flue gases of coal-fired power plants is a challenge due to the conditions of the sample media (temperature, moisture and velocity of flow) as well as the often low concentrations at which some species are present. In order to reduce the variability and error in these measurements, organisations such as CEN, ISO and the US EPA have produced standard methodologies. The methods used in the EU are not identical to those used in the USA and elsewhere but, since the methods are all based on similar principles, the results from each should be comparable. Most of the data produced from manual or CEM monitoring systems are not used for comparison or inventory studies but rather are used for immediate compliance monitoring (to flag up an instance when emission limits are exceeded) or to improve plant-specific emission factors. Chapter 5 gives examples of where manual or CEM measurement systems are used to meet international and national emission regulations.

5 Reporting to legislated requirements

A previous report by Sloss (2009b) discusses the requirements for power plants to report to international and national inventories. As mentioned before, these inventories are generally based on emission factor calculations, although the emission factors are often derived based on actual stack emissions measurements. The sections below summarise where emission factors are used and where stack gas measurements are required both international and nationally, with a few countries being selected as examples – a full list of requirements for all countries is beyond the scope of this report.

5.1 International

As discussed in Chapters 3 and 4, ISO allows representatives from member countries to work together to produce international standards for use globally. However, these standards are voluntary and would be superceded by any national standards. In the EU, CEN co-ordinates member countries to produce standards which are compulsory within the EU. EU member states may only use alternative methods when CEN standards are not available or applicable.

The IPCC provided detailed guidelines on how countries should report GHG emissions. The requirements include a 'Tier 'system, determining the level of assumed accuracy. Tier 1 estimates are based on a default approach based on aggregated data and default emission factors (from generalised emission factor databases or lists). Tiers 2 to 4 require increasing amounts of source-specific data, such as source-specific emission factors and operational data. These higher tiers require more actual measurement at sources to provide data to calculate source-specific emission factors, as discussed in Chapter 3.

The United Nations Environment Programme (UNEP) has established several international pollutant protocols such as the LRTAP Convention (Long Range Transboundary Air Pollution). These conventions tend to be voluntary and the requirements for reporting are somewhat flexible, with countries reporting data in whichever manner is most appropriate for them. Mercury is considered the trace element of greatest global concern. UNEP has begun negotiations to establish a global legally-binding instrument for mercury reduction which should be signed and ratified during 2013. At the moment it is unclear what form this instrument will take and whether it will involve any direct action at coal-fired power plants. But it is likely that countries will start to take steps towards reducing mercury emissions and, since coal combustion is the largest source of mercury emissions from human activities, it is likely that action will be taken in many countries towards evaluating emission sources for mercury. This could, in turn, lead to more requirements for mercury monitoring at coal-fired plants.

5.2 EU

As discussed in the previous report by Sloss (2009b), the European Pollutant Release and Transfer Register (E-PRTR), established in 2000, requires member states to report national emissions of listed pollutants on an annual basis. These are summarised in Table 1. The majority of these requirements are based on emission factor calculations. However, the emission factors are corrected to be plant-specific based on actual emissions monitoring data which are collected triennially.

The EU National Emissions Ceilings Directive (NECD) sets upper limits for each member state for the total emissions in 2010 for SO_2, NOx, volatile organic compounds (VOC) and ammonia (NH_3). To ensure compliance, member states must submit action plans and regular inventories. These are also based on emission factor calculations rather than actual measurements.

Table 1 Monitoring for inventories of particulates, SO_2 and NOx in different countries/regions (APEC, 2008)

	Australia	Canada	EU	USA
Inventory	National Pollutant Inventory	National Pollutant Release Inventory	European Pollutant and Transfer Register	National Emissions Inventory
Pollutants	SO_2, NOx, PM_{10} and $PM_{2.5}$	SO_2, NO_2, TPM, PM_{10} and $PM_{2.5}$	SOx/SO_2, NOx/NO_2, and PM_{10}	SO_2, NOx, PM and PM $_{2.5}$
Threshold	Burning = 400 t/y or Burning = ⩾1 t/h	*Reporting:* SO_2, NO_2, TPM – 20 t PM_{10} – 0.5 t $PM_{2.5}$ – 0.3 t *Stack specific:* SO_2, NO_2, TPM – 5 t PM_{10} – 0.25 t $PM_{2.5}$ – 0.15 t	SOx/SO_2, – 150,000 kg/y NOx/NO_2, – 100,000 kg/y PM_{10} – 50,000 kg/y	–
Monitoring	CEMs, Stack/Source Tests, MB, Fuel Analysis Data, ECs or EFs	CEMs, PEMs, Stack/Source Tests, MB, Engineering Estates, EFs or Emission Models	Direct measurements, (CEMs or source/stack testing)	Information from: Surveys compiled by US DOE, US EPA's Emission Trading System/CEMs programmes and others
Frequency	Annually	Annually	Annually	Annually

The following sections concentrate on several European schemes and regulations which require emissions monitoring and reporting at the individual plant level at coal-fired plants in member countries.

5.2.1 EU ETS

The European Emissions Trading Scheme (EU ETS) began in 2005. Annual reporting is required, and allowances are tracked in electronic registries established by each EU member. Under the scheme, CEMs can be used for CO_2 and other GHG monitoring only if the operator has received approval from the competent authority and has shown that the method used achieves greater accuracy than the calculated, emission factor, method. For reporting to the EU, CEN methods are preferred. If none are available, ISO methods are required such as ISO 12039 (*see* Appendix 1). This method is a performance standard in that it provides guidance on the use of CEM systems but does not define the CEM system itself (APEC, 2008):

Herold (2003) compared CO_2 emission factors used within EU member states for the EU ETS, IPCC and other reporting requirements. The study showed that, as of 2003 when the study was completed, nine EU member states (Denmark, Finland, Ireland, Italy, Germany, the Netherlands, Spain, Sweden and the UK) used country-specific emission factors which differed from those suggested by the IPCC. It may well be that other countries have developed country-specific emission factors since then. Table 2 shows the emission factors used by EU member states in 2002-03. The country-specific emission factors can be seen to vary the most for lignite (90.7–124.7 tCO_2/TJ; 27% difference). The factor for bituminous coal varies between 86.7 and 99.8 tCO_2/TJ, a 13% difference. The average EU emission factor for coal is similar to the IPCC default value.

Table 2 Comparison of IPCC default CO_2 emission factors and country-specific emission factors for solid fuels for Europe (tCO_2/TJ, basis NCV) (Herold, 2003)

Country	CO_2 emission factor, tCO_2/TJ											Source
	Primary fuels							Secondary fuels/products				
	Anthracite	Coking coal	Other bit coal	Subbit coal	Lignite	Oil shale	Peat	BKB and patent fuel	Coke oven/ Gas coke	Coke oven gas	Blast furnace gas	
IPCC default	98.3	94.6	94.6	96.1	101.2	106.7	106.0	94.6	108.2	47.7	242.0	
Austria	IE	IPCC	IPCC		IPCC	NO	IPCC	IPCC	IPCC			CRF 2003
Belgium		IPCC	IPCC	IPCC	IPCC			IPCC				CRF 2003
Denmark	NO	NO	95.0	NO	IPCC	NO	NO	NO	IPCC			CRF 2003
Finland			IPCC	NO	NO	NO	IPCC	IPCC	IPCC	40.5		CRF + NIR 2003
France	IE	IPCC	IPCC	NO	IPCC	NO	NO	IPCC	IPCC			CRF 2003+2002
Germany	IE	87.6	86.7	NO	111.1	NO	IE	93.3	108.3	44.0		CRF 2003, UBA 2003
Greece		IPCC	IPCC		124.7							CRF 2003
Ireland			IPCC				108.4	98.9				CRF 2003
Italy	NO	IPCC	97.5	94.6	IPCC	NO	NO	NO	IPCC			CRF 2003
Netherlands			96.7					94.0	103.0	44.0	200.0	CRF 2003
Portugal			IPCC					IPCC				CRF 2003
Spain	IE	96.4	99.8	99.6	117.4	NO		NO	106.2			CRF 2003
Sweden	NO	90.7	NO	NO	90.7	NO	107.0	NO	103.0			CRF 2003
UK	98.7	89.6	IPCC					111.6	106.6			CRF 2003
EU-14 average	98.7	93.0	94.8	96.7	105.5	NO	106.8	97.0	106.8			
EU average only CS	98.7	91.1	95.1	97.1	111.0		107.7	99.4	105.4	42.8		

Difference between EU-14 average and IPCC default	0.4%	−1.7%	0.2%	0.7%	4.3%		0.8%	2.6%	−1.3%			
Difference between CS average and IPCC default	0.4%	−3.7%	0.6%	1.0%	9.7%		1.7%	5.1%	−2.6%			
Czech Republic		IPCC	IPCC		IPCC				IPCC			CRF 2002
Estonia	IPCC					106.7	IPCC	IPCC	IPCC			CRF 2002
Hungary		IPCC	IPCC	IPCC	IPCC				IPCC			CRF 2002
Latvia			IPCC				IPCC		IPCC			CRF 2002
Poland		89.9	95.2		111.2				111.6			CRF 2003
Romania		IPCC	IPCC	IPCC	IPCC				IPCC			CRF 2003
Slovakia		94.8	93.8		100.4				106.8			CRF 2002
Slovenia	96.3		92.7	99.2	99.2				106.0			NIR 2003
Average including accession countries	97.7	93.3	94.6	96.9	104.3	106.7	106.6	96.5	107.4			

IPCC = IPCC default EF used in CRF reference approach table 1.A.(b), NO = not occurring, IE = included elsewhere, NA = not applicable, blank = no value reported, CS = country specific
Fuel categories based on IPCC nomenclature, national energy balances may assign coke oven gas and blast furnace gas to gaseous fuels

Herold (2003) recommends that the most accurate emission estimates could be produced from coal-specific emission factors. Ideally this type of data would be collected from coal producers and importers and should be regularly updated and made available to the reporting installations. This could be co-ordinated at an international or national level by the EC or national authorities. It would be necessary to ensure that reporting both from the installation and by any national programme used the same emission factor and data to ensure that there were no inconsistencies in values reported for each country as a whole. If default values are set by countries or member states it may be necessary to establish rules at the EC level in order to ensure comparability, consistency, transparency and a defined level of accuracy. Herold (2003) recommends that each member state and each installation should report how the emission factors were derived and this should be co-ordinated with international fuel definitions. Default emission factors would then only be used when no more accurate emission factors are available. Herold argues that the requirement to produce fuel-specific emission factors by the reporting source would not be a particular burden since fuel vendors are commonly required to provide information on fuel composition and properties including the carbon content.

From the APEC (2008) data it would seem that only 18 installations in four EU member states had opted to use CEMs for CO_2 reporting rather than the emission factor method. This includes one or more in Denmark, eight in Estonia, one in Finland and eight in the UK.

The majority of plants in the EU therefore calculate and report CO_2 emissions based on measurements of fuel burn and the carbon content of the fuel according to the EU ETS guidance and site-specific plans. The data are entered via standard forms defined by the national authorities. For example, the UK Environment Agency provides forms and guidance here: http://www.environment-agency.gov.uk/business/topics/pollution/32244.aspx.

Salway and others (2007) have produced a detailed report on how coal-fired power stations can collect and report data to meet the EU ETS requirements and the interested reader is referred to this excellent document for further detail.

5.2.2 IPPC

Although in the EU the current IPPC (Integrated Pollution Prevention and Control) Directive includes the requirement to address plant efficiency it does not specify a standardised requirement for the evaluation of plant efficiency as such on all plants. However, such requirements may be written in to plant permits on a site-specific basis. For example, plants in Ireland are required to perform an energy audit of the whole site, including energy consumption on site. This form of energy audit is more concerned with the overall efficiency of the whole facility rather than of the plant itself (Owens, 2004).

Under the IPPC, plants are required to apply BAT technologies to deal with defined pollutants. Currently there is no BAT requirement for energy efficiency. There is a plan for a BREF (BAT reference document) on energy efficiency (Roukens, 2004). Those working on the BREF have been challenged by the lack of data on energy efficiency. These data are available within the industry but are regarded as commercially sensitive and not made available, as discussed in Chapter 2 (Litten, 2004).

The IPPC Directive lists target pollutants with associated threshold values (in kg/y). Any source exceeding these threshold values must report total emissions of each pollutant of concern on an annual basis (Necker and others, 2002). However, the requirements of each plant to comply with the IPPC Directive is determined on a plant-by-plant, permit specific basis. Each plant permit is determined to ensure that the plant complies with all monitoring requirements from those at the international level, such as the LCPD (*see* below), down to national and even regional requirements. For example, plants in sensitive or highly polluted areas may have more stringent permits set than others.

5.2.3 LCPD/IED

Under the Large Combustion Plant Directive (LCPD) in the EU, cogeneration (combined heat and power) is promoted and, where heat delivery is feasible, cogeneration can be considered as BAT. Cogeneration and combined heat and power plants are far more efficient than standard power plants. But thermal efficiency cannot be directly compared with electrical efficiency, as discussed in Chapter 2. There is no definition of BAT or BAT levels for energy efficiency in the current EU legislation (van Aart, 2004).

CEMs for particulates, SO_2 and NOx have been required under the LCPD for all plants over 100 MWth since November 2004 and the systems are subject to strict quality control and assurance standards. However, under the LCPD, there are three options for compliance with emissions limits of SO_2 and NOx which are relevant to determining how monitoring should be applied:

- Plants can '**opt-in**' to comply with prescribed ELVs – emission limit values. Plants must continually monitor emissions of prescribed pollutants (particulates, SO_2 and NOx) and must not exceed the prescribed ELVs.
- Plants can avoid having to comply with ELVs by continue running restricted hours until closure (20,000 h/y). These are known as '**opt-out**' plants.

- Remaining plants can achieve equivalent emission reductions via a National Emissions Reduction Plan (**NERP**), contributing towards a defined reduction in emissions through various routes.

The following sections discuss the different monitoring approaches under the different compliance options.

Opted-in plants

Plants which have opted-in have agreed to comply with the ELVs defined in Table 3. Compliance with the ELVs is determined based on CEM monitors. As can be seen from the footnotes in the table, compliance for some plants firing high sulphur coals may involve demonstrating a 92% or 95% SO_2 reduction rate, depending on the age of the FGD unit. In these situations, two CEM systems are required – one upstream and one downstream of the FGD unit. Both CEM systems must be subject to the same quality assurance (QA) requirements to ensure comparability of results and validity of the reduction value. Table 4 shows the detailed requirements for plants opting-in to ELVs. The ELV is established largely on a monthly basis – the monthly mean for each plant cannot exceed the ELV as prescribed. However, the limit for 48 h averages is set at 110% of the ELV so there is a little leeway

Table 3 Nominal LCPD emission limit values for large plants (all fuels, plants >300 MWth) (JEP, 2006)

	Existing plant (Part A)			New plant (Part B)		
	Solid fuel	Liquid fuel	Gas	Solid fuel	Liquid fuel	Gas
SO_2	400[1,2,8]	400[1]	35[4]	200[3]	200	35[4]
NOx	500[1,5,6,9]	400[1]	200[1]	200	200	100[7]
Particles	50[1,10]	50	5	30	30	5
Ref O_2, dry	6%	3%	3%	6%	3%	3%

Notes:
Part A processes are regulated by the Environment Agency while Part B processes are controlled by local authorities.
1 Existing plant limits for installations greater than 500 MWth
2 Alternatively, 94% removal efficiency for new FGD or 92% for existing FGD (installations before 1 January 2001)
3 Alternatively, 95% removal efficiency AND a maximum ELV of 400 mg/m^3
4 Different limits for liquefied gas, coke oven gases, blast furnace gas, syngas, etc
5 Existing plant NOx limit of 200 mg/m^3 from 1 January 2016
6 600 mg/m^3 if operating <2,000 h/y until 31 December 2015 and 450 mg/m^3 if operaing <1500 h/y from 1 January 2016 (5 y rolling average)
7 Natural gas only. Other gases 200 mg/m^3
8 800 mg/m^3 if operating <2000 h/y until 1 January 2016 and <1500 h/y from 1 January 2016 (5 y rolling average)
9 1200 mg/m^3 for fuels with a volatile content <10% (until 1 January 2018)
10 Existing plant particle limit of 100 mg/m^3 for low CV solid fuel (<5.8 MJ/kg), moisture >45%, CaO >10% (moisture + ash) >60%

Table 4 Detailed LCPD emission limit values for opted-in coal-fired plant (JEP, 2006)

LCPD existing plant (before 1 January 2008)	NOx	SO_2	Particles
Monthly mean, mg/m^3	500	400	50
48h mean (110% of ELV), mg/m^3	550	440	55
Percentile on annual basis, %	95	97	97
95% confidence interval, %	20	20	30

for small exceedences on a short-term basis. However, a fixed percentage of all the 48 h averages must not exceed this value, also shown in the table. The 48 h calendar period is a fixed period rather than a rolling average (JEP, 2006a).

In the situations where opted-in plants cannot meet the ELV due to the characteristics of the fuel, they may be required to report a minimum FGD SO_2 removal efficiency. This is >94% for most plants, although >92% is acceptable for plants where the plant is already committed to fitting FGD. The ratio is based on the sulphur captured (not emitted) to the sulphur in the fuel.

$$\% \text{ S reduction} = [1 - 0.95\ FGD_o/FGD_i] \times 100$$

Where FGD_o is the SO_2 concentration at the FGD outlet and FGD_i is the SO_2 concentration at the FGD inlet (both in mg/m^3). The concentrations used are either the hourly averages or monthly averages, as selected by the plant operator. Alternatively, the operator can calculate the total tonnage of sulphur input in the coal versus the total tonnage emitted (JEP, 2006b).

NERP plants

Annual mass emission limits have been set for all NERP plants. Each plant is given plant-specific annual mass emission limits according to the national budget. For example, NERP plants in the UK have an annual ELV for 1.8 t/GWh for both SO_2 and NOx. These limits are transferable (tradeable) to other sources in the NERP scheme. Compliance with the emission limit is determined (excluding periods of start-up and shut-down) using CEM systems.

The total tonnage of emissions is determined from the tonnage of emissions divided by the power produced (GW). Where CEMs are present, the emissions are calculated from the emission concentration (usually an hourly average) multiplied by the stack flow rate to give an hourly mass emission. The monthly or annual tonnage is then calculated as the sum of the hourly tonnages within the reporting period (JEP, 2006b).

Opted-out plants

Plants that have opted out must not run for more than 20,000 hours starting on 1 January 2008 and ending no later than 31 December 2015. However, it is often the case that existing national limits, or limits defined under the IPCC (*see* Section 5.2.2), mean that emission limits still apply. For example, in the UK opted-out plants must keep emissions of NOx below 1.8 t/GWh (requiring the use of advanced combustion technology) and SO_2 below 7.5 t/GWh (requiring the firing of low sulphur coals).

Some of these plants may already have CEM systems in place. However, because of the low load factor at the plant, the quality control requirements for the CEM system are relaxed considerably. In situations where continuous monitoring is not possible or required, measurements are required at least every six months. In some situations, the use of emission factors is considered efficient. In these cases, the emission factor for SO_2 is based on the average sulphur content of the actual fuel burnt during the reporting period. For NOx and particulates, emission factors are calculated from existing/historic plant data or from factors which have been obtained from similar plants firing similar fuels (JEP, 2006a).

Determination of compliance for all plants under the LCPD

The reporting requirements for plants under the LCPD are as follows (JEP, 2006b):
Monthly fuel use and total release data – includes data from start-up and shut-down periods. These data are used to ensure no ELV limit is exceeded and, where applicable, for reporting to the national pollution inventory.
Monthly particulate, SO_2 and NOx release data – excludes data from start-up and shut-down periods. These data are used for comparison of total cumulative emissions (t or t/GWh) with current allocations under NERP.

Monthly mean concentrations and annual percentiles – excludes data from start-up and shut-down periods. This includes determination of FGD efficiency. The monthly particulate total is used for NERP and for reporting at opted-out plant.
Annual energy input and total emissions – includes data from start-up and shut-down periods. These data are used for the LCPD inventory reporting. The energy use is calculated from the fuel burn (tonnes), multiplied by the net CV.

Plants do not need to report emissions for periods of start-up or shut-down or missions of unabated operation (FGD out of service) as long as these remain under the prescribed limit of 24 hours of continuous operation and 120 hours of cumulative operation in a 12-month period. This means that emissions are recorded when the unit is considered to be running in normal operation or minimum stable generation (MSG). However, these concentrations are still measured and recorded (JEP, 2006a).

CEMs systems for particulates, SO_2 and NOx must be able to provide data averaged over a short sampling period of a few seconds to two minutes. The maximum time period that can be represented by one instantaneous sample is two minutes. Data loggers sampling a rolling average should therefore sample at least every two minutes. CEM systems are subject to zero and span checks and ongoing maintenance and therefore do not always run truly continuously over extended periods of time. A valid hour of data is obtained when at least 40 minutes of data are available for that hour during MSG (*see above*). If a CEM system malfunctions then some data points must be discarded. CEM systems must be available and functional with less than ten unavailable days within a calendar year. Unavailable days are those in which more than three-hourly average values are lost. This equates to a required daily availability of 97.3% and means that most plants will have two identical or comparable CEM systems in place with one acting as a back-up for the other (Necker and others, 2002).

An hourly average value is then reported, in mg/m^3, corrected to standard reference conditions. The validated value is then determined by subtracting the uncertainty (20% of gases and 30% for particulates) from the measured value. The uncertainty is defined under the LCPD as a percentage of the ELV (at 95% confidence). However, in situations when the measured value is very low, that is much lower than the ELV, then this could lead to confusing values which may be calculated as either zero or even a negative value.

A 48-hour average is validated for all pairs of consecutive calendar days during which a minimum number of hours worth of valid data have been obtained. The monthly average is calculated from the validated hourly averages, provided that at least three validated 48-hour averages are available within that month. As shown in Table 3, the emission values must be corrected to reference oxygen concentrations. Temperature and pressure must also be monitored continuously under the requirements of the LCPD.

In November 2010, the European Council of Ministers formally adopted the EU **Industrial Emissions Directive (IED)** and EU member states now have until the end of 2012 to transpose the directive into national legislation. The directive will become effective from 1 January 2016, although there is some limited leeway for member states to deviate from the requirements for economic reasons and there is a limited life derogation (LLD) option which limits the remaining operation life of plants which cannot comply (17,500 hours of operation between 1 January 2016 and 31 December 2013 after which they must close). The IED is intended to combine and update the existing legislation including the LCPD and IPPC Directives. The IED focuses largely on BAT and introduces minimum standards with respect to inspection and review of permit conditions and compliance reporting. The existing ELVs from the LCPD will now be revised to bring them into line with values that would only be achieved with BAT. As with the LCPD, the IED includes stricter ELVs for the largest plants (McClosky, 2010).

The IED includes requirements for emissions monitoring and reporting which are reported to be far more stringent than those within the previous legislation (McClosky, 2010). The BREFs are still under review and so, as yet, it is not clear what exactly will be required at each plant. However, new monitoring requirements will be established which may include additional monitoring requirements for species such as mercury (EC, 2010).

5.2.4 National example – UK

Individual countries within the EU must comply with the above requirements. However, over and above this each country must transfer the EU requirements into national action plans. Although these vary from country to country, depending on the state of existing plants, there are general similarities in approaches. It is not possible to summarise the situation in each EU member state within this report. However, the summary given for the UK below is fairly representative of the type of requirements applied to existing coal-fired plants.

Plant efficiency in the UK is determined based on actual performance monitoring. Final power metering systems determine the electrical output. Turbine and boiler efficiencies are determined based on actual performance measurements and correction factors. The efficiencies calculated from the plant performance are then compared with those calculated from the residual fuel stock to give an indication of any error in either delivery information or consumption measurement. This produces a significant amount of cross-checked data which can be used for consumption forecasting and investment appraisal (CIAB, 2010).

The UK Environment Agency (UK EA) introduced efficiency monitoring into the Pollutant Inventory in 2009 and requires that plants report based on thermal input from fuels and electricity generated. However, the actual efficiency calculation is done internally by the UK EA in a form of bench-marking process (*see* Section 2.4.2; Weatherstone, 2010).

Emissions of CO_2 are estimated on the fuel-burn approach which is considered to be more accurate than actual monitoring. Total fuel burn is measured and combined with proximate fuel analysis to give a plant-specific emission factor (CIAB, 2010).

All coal-fired plants in the UK are subject to an individual site PPC (Pollution Prevention and Control) permit which describes the individual reporting requirements of that plant. All plants must comply with the LCPD as set by the EU. But, over and above this, the UK EA specifies additional requirements which includes limits set under the NERP approach. The UK EA has decided how to reach the required reduction target under the NERP and has translated this into plant-specific requirements for each of the UK plants to which the NERP applies. This can be simplified as follows (JEP, 2006b):

- Opted-out plants – these plants must comply with ELV limits as defined within the LCPD. This effectively requires these plants to apply BAT for NOx (down to 500 mg/m^3) and FGD for SO_2. Alternatively the SO_2 limit can be met by using ultra-low sulphur fuel (down to 400 mg/m^3) and/or a minimum sulphur removal efficiency. Compliance with the ELV must be demonstrated, based on monthly averages.
- NERP plants – the UK EA has determined that these plants must meet an annual ELV of 1.8 t/GWh for both SO_2 and NOx, equivalent to the monthly mean concentrations of opted-in plants. However, the site-specific NERP limits are transferable between all operators within the national NERP system. So one plant may emit more as long as another plant can run less and keep the total the same or less.
- Opted-out plants – these plants have a limited running time of 20,000 hours between 2008 and 2016. However, these plants must still meet limits determined by the UK EA. This means an average SO_2 limit of 7.5 t/GWh, which requires the use of low sulphur fuel, and an average NOx limit of 1.8 t/GWh, which requires advanced combustion technology.

All plants, regardless of whether they are opted in or out or NERP, must comply with the LCPD monthly particulate limit of 50 mg/m^3. This can be met with ESP (electrostatic precipitator) systems. Plants with FGD installed are expected to meet a tighter UK BAT particulate limit of 25 mg/m^3.

Plants are required to monitor emissions on a total annual tonnage emission basis. Based on the ELV, this value is 9 t/y for SO_2 and 12.7 t/y for NOx. The limit for NERP plants is not specified as long as the combined total for all NERP plants is below the set amount. For opted-out plants the limit is 9 t/y for SO_2 and 6.5 t/y for NOx.

Over and above this, the UK EA may tighten emission limits and monitoring requirements further in areas which may be deemed to be particularly polluted or at risk from environmental harm. Air quality standards must be met in all areas. In general, all plants in the UK are required to have CEMs installed for particulates, SO_2 and NOx, although the frequency of reporting may vary according to the site-specific permits (JEP, 2006b).

5.3 North America

As discussed in previous chapters, North America has its own standards for measuring emissions which are based on the same principles as those in the EU but which vary in how they are applied in practice. The following sections give a brief summary of the monitoring requirements in Canada and the USA.

5.3.1 Canada

There does not seem to be a national standard for reporting plant efficiency in Canada. As mentioned in Chapter 2, states such as Alberta report their plant efficiency on a monthly and year-to-date basis based on coal input and electric output whilst others such as Saskatchewan use online performance calculation software (CIAB, 2010).

The Canadian GHG Emissions Reporting Programme applies to the largest GHG emitters (>100 kt/y of CO_2 equivalent). These values are reported online based on the usual options (monitoring/direct measurement, mass balance, emission factors or engineering estimates) (APEC, 2008). The state of Alberta uses emission factors to estimate CO_2 emissions taking the LOI (loss on ignition, a determination of unburnt carbon) into account (CIAB, 2010).

Like many countries (such as EU member states and Australia, *see* Section 5.4), Canada has reporting thresholds for emissions from large sources (over 50 MWe) such as coal-fired plants. As shown in Table 1, for species such as CO, particulates, SO_2 and NOx, the threshold is 5 t/y for stack-specific emissions. The general options for emission monitoring are reporting are very similar to Australia with everything from emission factors and PEMs to manual monitoring and CEM systems being allowed on most sources (APEC, 2008). The guidelines for CEM systems are performance based and much of the methodology is copied from or similar to that in the USA. The actual requirements are determined by plant-specific permits (CIAB, 2010).

However, over and above this, there are more stringent emission limits for SO_2, NOx and PM_{10} for 'new' plants (cut-off date not given). Previous emission limits were based on input – being expressed in allowable emission volumes per unit of heat energy input. The new emission limits are output based – being expressed as allowable emission volumes per unit of electricity output. This is intended to encourage more efficient electricity generation. Under the new system, CEMs are required for SO_2 and NOx on all coal-fired units in Canada. Individual states and provinces within Canada must comply with the national requirements but may set more stringent emission limits or reduction targets. (APEC, 2008).

Since the US EPA's CAMR (Clean Air Mercury Rule) was vacated, Canada is currently the only country with legally-binding emission limits for mercury from coal-fired power plants which require significant action to be taken. Part of the Canada-Wide Standards (CWS) requires the monitoring of the mercury emissions to ensure compliance. The CWS comprise provincial caps (kg/y) for existing plants and specific capture rates (% capture in coal burnt) or emission limits (kg/TWh) for new plants. The monitoring requirements for each of these approaches are included in the monitoring protocol provided by the CCME (Canadian Council of Ministers for the Environment, 2007). For plants commissioned before 2012, the approaches for determining total annual mercury emissions are:

- stack testing and flow monitoring, using appropriate CEM systems;
- mass balance calculations based on the mercury content of the coal and the mercury content of the coal combustion residues/ash. This should be supplemented with an annual stack test to corroborate the mass balance result. If the values do not match within ±20%, the utility must account for the discrepancy;
- another equivalent method that can be shown to yield results with an accuracy equal to or greater than the two methods outlined above.

For plants commissioned after 1 January 2012, CEMs are required on all units except those which can be shown to be low mass emitters (LMEs) – emitting below the thresholds:

- 10 kg of Hg per stack per year for existing plants/new units with multiple stacks; or
- 20 kg of Hg per stack per year for existing plants/new units with one stack.

However, although the plants are excused from fitting CEM systems, they are still required to submit total mercury emission values based on the mass balance technique mentioned above. The monitoring protocol document (CCME, 2007) provides detailed but clear instructions on reporting requirements and methods and the interested reader is referred to the original document for further information.

5.3.2 USA

Plants in the USA estimate their efficiency as the heat rate (HR). This is the amount of energy (Btu) necessary to provide 1 kWh of electricity to the grid, as described in Appendix 1. HHV is always used in the USA. Overall efficiencies are most commonly estimated using the input-output method, although plants may also use the output/loss method taking steam generator losses into account (CIAB, 2010).

In the USA, under the new US EPA GHG rule, BACT (best available control technology) guidance is included which is not a regulation but rather a recommendation to be written in to future permits based on improving the efficiency of each plant on a plant-by-plant basis. Although for some plants this could theoretically include CCS (carbon capture and storage), the costs are currently too high. However, the ruling does indicate that energy efficiency improvements should be considered under BACT. This means that new plants are likely to be supercritical or ultra-supercritical plants (Holly, 2010).

Unlike the EU, the US EPA requires CEM systems for CO_2 monitoring. It would appear that the US EPA regard the difficulties in measuring coal input and variations in coal characteristics as factors which make estimation methods less reliable (*see* Section 4.2.1; Seligsohn, 2010).

In 2009 the US EPA ruled that, beginning in March 2011, companies from selected sectors or with facilities emitting more than 25,000 t/y of GHGs (CO_2-e) must report the emissions annually (Singh and others, 2010). This is roughly equivalent to burning 10,800 t of coal, 2.3 million gallons of fuel oil or 460 million cubic feet of natural gas on a 24 hours per day, 7 day per week basis (Sibold and others, 2010).

The US EPA's GHG Reporting Program (GHGRP) is the first and only current national reporting programme to require facilities to report emissions and other relevant data on GHGs. The data are reported online. With respect to emissions from coal, the rule currently applies to around 3000 stationary combustion sources and 114 underground coal mines. Stationary fuel combustion facilities represent the largest group of reporting sources, with municipal landfill facilities (255 sources) a close second (Sibold and others, 2010).

The GHGRP was developed based on existing GHG reporting programmes (such as those produced in California and Massachusetts). The Program makes use of existing monitoring equipment (such as flow meters, weighing scales, CEMs) as much as possible and requires facilities to calibrate monitoring equipment to certain specifications. Where actual monitoring is not possible, calculation methodologies are prescribed (Sibold and others, 2010).

The largest emitters of CO_2 (such as large coal-fired plants) must use 'Tier 4' reporting methods. This means that a CEM system for CO_2 is required. If a plant does not have a CO_2 monitor already in place then it may use alternative methods for CO_2 estimation until a monitor is installed. With such monitors come the need for a monitoring plan, maintenance requirements and auditing. Unlike previous US-based GHG monitoring programmes, the US EPA does its own auditing.

Any CEMs used for reporting such data must be running in continuous operation and must be able to sample, analyse and record data at least every 15 minutes, and the emissions and flow data must be reduced to 1-hour averages (APEC, 2008).

The use of an online reporting tool for the GHGRP, (e-GGRT) is intended to reduce the burden on the reporter, improve accuracy, enhance the ability to conduct electronic reviews to ensure data quality, consistent format to improve data comparability and improved data availability. The tool is reported to be self-guided with step-by-step instructions and use friendly screens. A bulk upload feature will allow direct electronic transfer of data from existing data systems at the reporting sources. At the moment, the system is not entirely compatible with some state GHG reporting rules and so some sources may have to report their emissions separately to state and national requirements. The data is to be reviewed and verified by the US EPA with some on-site audits of selected facilities (Sibold and others, 2010). More information is available from www.epa.gov/climatechange/emissions/ghgrulemaking.html.

As mentioned earlier, the use of CEMs for CO_2 monitoring is preferred in the USA under the impending GHG legislation. However, in the past, CO_2 data for plants in the USA have come from a combination of emission factors and CEM measurements. Ackermann and Sundquist (2008) reviewed data on CO_2 emissions for 2004 from two separate data sets in the USA:

1 The EIA (Energy Information Administration department of the US DOE) data set is based on calculating CO_2 emissions from fuel consumption data reported by combustion plants along with sector classification (utility, commercial, industrial), fuel type and total heat input
2 The eGRID dataset, of the US EPA, is based on a combination of data. Some comes from calculations based on fuel consumption and emission factors, some from CEM measurement and some from a combination of the two (from different units etc). In 2004, 61% of the plants used the calculation/EF method, 29% used CEMs and 10% used a combination of the two.

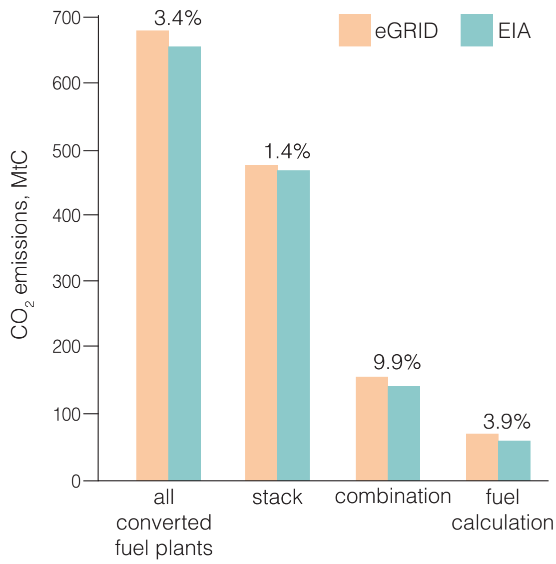

Figure 6 Comparison of estimates of US CO_2 emissions (Ackermann and Sundquist, 2008)

Ackermann and Sundquist (2008) compared the data sets and found significant differences in the values from each data set. Figure 6 shows the values for CO_2 emissions estimated for all the plants and then for the different plant types – those that used stack monitoring, those that used fuel calculations and those that used a combination of the two methods. The differences in values between the EIA and eGRID data were due to a number of issues, such as the way data were handled along with differences in procedures and inherent method bias.

Sources in the USA must report emissions of major pollutants to the National Emissions Inventory (NEI) and the Toxics Release Inventory (TRI). The data are compiled by the US Department of Energy's Energy Information Agency (US EIA) and are based on emission factor calculations (APEC, 2008). Over and above this, the USA has several somewhat overlapping monitoring requirements which all fall under the umbrella of the Clean Air Act. These are (APEC, 2008):

- NSPS – new source performance standards, applying to TSP (total suspended particulates, opacity, SO_2, NOx (as NO_2), PM_{10} and opacity) on new, modified an reconstructed facilities. This requires CEMs for SO_2, NOx and opacity;
- NSR – new source review, which is a plant-specific permit scheme, the requirements of which are determined prior to construction;
- OPs – operating permits apply to all major sources and include plant-specific monitoring requirements. Similarly to the IPPC permit-based system in the EU (*see* Section 5.5.2), plants in the USA have site-specific permits for operation which take into account all the relevant legislation at

Table 5 Active programmes that require Part 75 monitoring (US EPA, 2009)

Programme	Affected sources	Parameter(s) measured	Accounting or averaging period	Data used for programme compliance
Acid rain Program	EGUs and other combustion sources that opt in to the SO_2 cap and trade programme (48 States)	SO_2, tons	Annual, cumulative	Yes[a]
		CO_2, tons	Annual, cumulative	No[b]
		NOx, lb/ million Btu	Annual, average	Certain units only[c]
		Heat input, lb/mmBtu	Annual, cumulative	In some cases[d]
		Opacity, %[f]	Varies[g]	No
Clean Air Interstate Rule (CAIR)[h]	EGUs and certain non-EGUs (if States elect to bring them in)	SO_2 and NOx, tons	Annual, cumulative (25 States)	Yes[a]
		NOx, tons	Ozone season[e], cumulative (25 States)	Yes[a]
Regional Greenhouse Gas Initiative (RGGI)[i]	EGUs (25 States)	CO_2, tons	Annual, cumulative	Yes[a]

a The cumulative annual tons of SO_2 or CO_2 (for RGGI) and the cumulative annual or ozone season tons of NOx emitted must be less than or equal to the number of emission credits (allowances) held
b At present, CO_2 is not a Federally regulated pollutant, although Congressional action to regulate CO_2 emissions is expected in the near future. title IV of the Clean Air Act requires only an estimate of annual CO_2 mass emissions from electrical generating units
c Under 40 CFR part 76, certain coal-fired units are required to meet an annual NOx emission limit
d If a unit exceeds its annual NOx emission rate limit under Part 76, the cumulative annual heat input is used to calculate the excess emission penalty
e The ozone season extends from 1 May to 30 September
f Required only for coal-fired units and certain oil-fired units in the Acid Rain Program
g Varies according to State and/or other Federal requirements
h Implementation dates: 1 January 2008 for CAIR NOx rules; 1 January 2009 for CAIR SO_2 rule
i The RGGI is exclusively a State programme

international, nation, state, regional and local level. This means that the monitoring requirements at one plant may differ significantly from those at another plant;

- ARP – the Acid Rain Program, a cap and trade scheme for SO_2 and NOx. Participation in trading generally requires the use of CEMs;
- NBTP – NOx Budget Trading Programme – a cap and trade scheme specific to the eastern USA which generally requires CEMs for NOx on affected plants.

Part 75 of the Code of Federal Regulations (CFR) lists the requirements and standards for measurement of the major pollutants from stationary sources. As shown in Table 5, Part 75 includes monitoring guidance for compliance monitoring for several distinct environmental programmes. The table includes details of what pollutants must be measured, the units, the accounting period and whether the measurement is actually used to determine compliance.

One of the most important aspects of Part 75 is that, although it lists manual monitoring methods, it generally requires the use of CEMs for units that combust coal or other solid fuels. Part 75 includes guidance on selecting the most appropriate monitoring technology, installation and certification, monitoring and record keeping, QA/QC and reporting (US EPA, 2009).

The US EPA requires emissions of major pollutants to be reported, in many cases, in the form of lb/MBtu (lbs per million British thermal units). In order to convert the values measured by a CEM system into these units, the operator must use a fuel specific 'F-Factor' to determine the rate of heat input. These F-Factors are listed in Appendix F of Part 75 of the CFR (US EPA, 2009).

The US EPA is currently finalising a new Air Toxics MACT rule which will include stringent emission limits for, amongst other things, chlorine and Hg. This is likely to result in increased monitoring requirements for these species.

5.4 Australia

In Australia, the Generator Efficiency Standards (GES) is a voluntary scheme under which generators can report annually on their efficiency and performance. The website provides details on how to calculate the plant efficiency based on the fuel's gross calorific value and expressing the result as generated efficiency or sent-out efficiency. Since 2004 the best practice efficiency guidelines defined for new plants have been: natural gas plant, 52% net thermal efficiency (HHV); black coal plant, 42% net thermal efficiency (HHV); and brown coal plant, 31% net thermal efficiency (HHV). The measure is implemented through legally binding, five-year Deeds of Agreement between the Australian government and participating businesses. The details can be found at: http://www.environment.gov.au/archive/settlements/ges/index.html.

New South Wales (NSW) has a Greenhouse Gas Reduction Scheme (GGRS) which includes the requirements of electricity generating systems to determine and substantiate Percentage Performance Improvement. This will then allow performance monitoring of 'greenhouse intensity'. The minimum level of monitoring for this is at the unit level and involves monitoring of the performance of the boiler, the turbine and the auxiliary demand. The actual requirements for monitoring are relatively ill-defined, with the decision on how to report (what methods and how often, from half-hourly to annually) resides with the plant operator. One option is the efficiency approach and this involves four steps (APEC, 2008):

Step 1 calculate the boiler efficiency using the 'heat loss method' using unit instrumentation;

Step 2 calculate the boiler thermal output (heat transferred to steam) by measurement of the feed water and steam flows, pressures and temperatures;

Step 3 calculate the fuel feed rate by dividing he boiler thermal output by the calculated boiler efficiency and the fuel calorific value (on an HHV basis);

Step 4 calculate the GI using the calculated fuel feed rate, the carbon content of the fuel and the sent-out power generation.

A more direct method involves the direct measurement of fuel flow to a unit together with fuel analysis and sent out power generation values (APEC, 2008).

The Australian Government established a National Greenhouse and Energy Reporting Act in 2007 with a detailed associated protocol to ensure alignment of measurement and estimation of GHG and energy use. The emissions from plants emitting over 25 ktCO_2/y can be reported by one of three means (APEC, 2008):

- use of a designated emission factor;
- fuel and raw material analysis (mass balance);
- direct monitoring using CEMs or PEMs.

The Australian government has postponed plans for a GHG ETS until 2013 at the earliest (Harries-Rees, 2010).

Large sources in Australia must report emissions over a specific threshold to the National Pollutant Inventory (NPI; *see* Table 1, page 37). This includes sources burning over 2000 t/y of fuel or waste. Emissions reported to the NPI can be obtained by any of the usual routes: mass balance, fuel analysis or engineering calculations, sampling or direct measurement or emission factors, as discussed in Chapter 3. Australia has no national standard for emissions monitoring at coal-fired plants but each state may set its own requirements. For example, New South Wales has a load-based licensing scheme for particulates, SO_2 and NOx which requires either CEMs or periodic monitoring. Figure 7 shows the regulatory framework which is applicable to coal-fired power plants in NSW. The system is a mixture of a plant-specific licence requirement, which incurs a fee per pollutant volume emitted, and the requirements to report to the Australia-wide NPI. Australia has its own national standards for

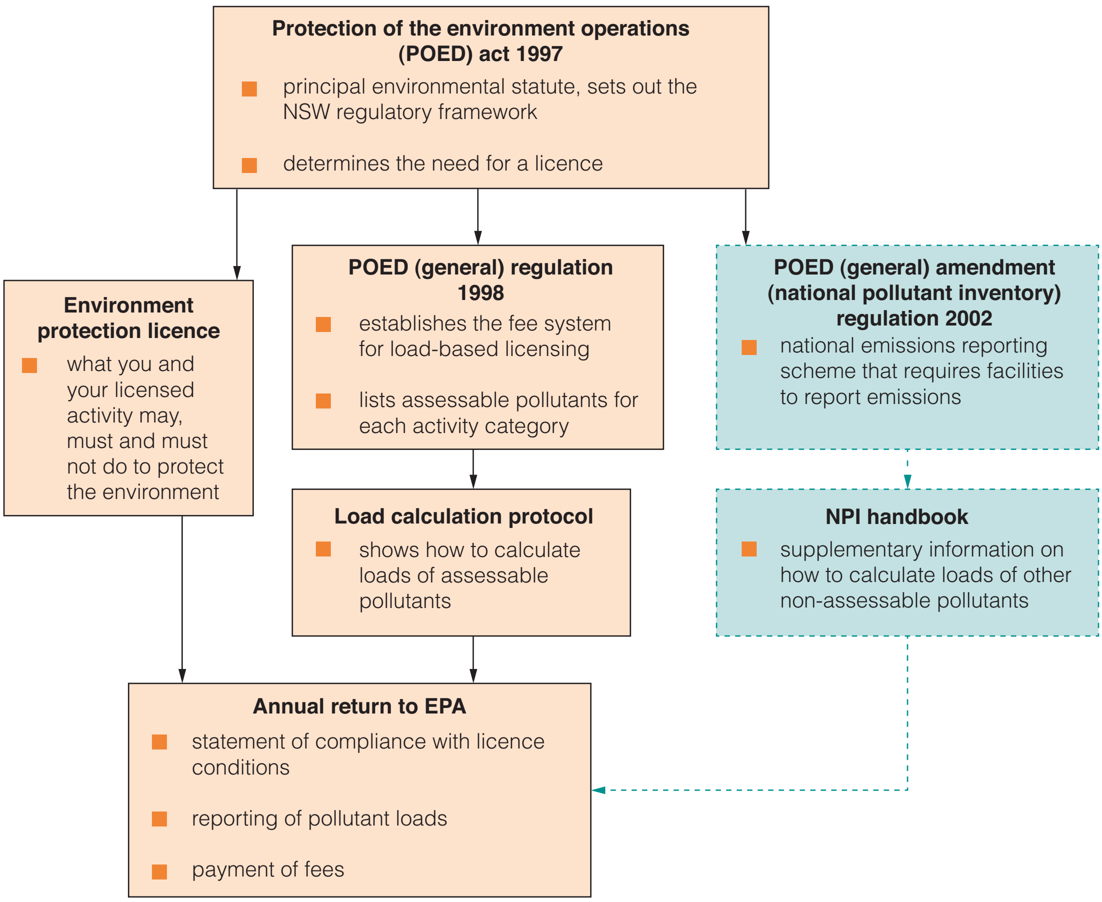

Figure 7 Overview of regulatory framework affecting coal-fired power plants in New South Wales, Australia (APEC, 2008)

monitoring pollutants but these tend to be quite similar to those defined by CEN or ISO. In areas such as NSW, a handbook is published to help sources determine the most appropriate methods of estimating or measuring emissions (APEC, 2008).

For the load-based fee system, there are four categories of pollutant loads (APEC, 2008):
- accessible – this the defined as the lowest estimate obtained from the remaining three categories below and it is this value that is used to calculate any fee owed;
- actual – mass in kg released from the source;
- weighted – actual load adjusted using load-weighting methods defined in the measurement protocol;
- agreed – the target or limit defined within the Load Reduction Agreement as part of the Licence agreed with the local environmental protection agency.

Table 1 compared the inventory requirements for large sources under the emission inventories in Australia, Canada the EU and the USA.

5.5 Asia

Due to the rapid economic and industrial growth in areas such as Asia, emission monitoring and compliance with emission standards are becoming more important. In some countries, such as Japan and Thailand, emission monitoring regimes are equivalent or superior to those in place in the EU and North America whereas other countries have significant room for improvement. Many areas will find the cost and manpower required to install and maintain emission monitoring equipment prohibitive. In some situations the local authorities have neither the funds nor the staff to be effective in ensuring compliance with any existing standards. Non-compliant plants may well continue to operate undetected or will find some political, economic or corrupt means of avoiding fines or closure (USAID, 2007).

5.5.1 China

Power plants in China report their efficiency monthly. This is based on electricity supplied to the grid, which is metered at each plant. The fuel input, which can often be a mix of coal, oil and gas, is sampled to determine the calorific value which is then expressed as an equivalent 'standard coal' quantity based on HHV. The efficiency data are all collected by the China Electricity Council which publish average figures on a national and provincial basis. However, the data on individual plant or company performance are not published (CIAB, 2010).

The China Electricity Council produced standard DL/T 904-2004 which includes methods for the measurement of boiler efficiency which is voluntary. However, in practice it would appear that plants calculate their efficiency based on 'standard coal' consumption (gce/kWh – grammes of coal equivalent, since some plants also fire supplementary fuels such as oil and natural gas) and net electricity supplied to the grid, as discussed in Chapter 2.

According to APEC (Asia-Pacific Economic Cooperation, 2008), although China has relatively stringent and forward-thinking legislation with respect to pollution and control, the technologies installed are not always operated as they should be and the monitored data are 'not often' being collected by local authorities and used for compliance. However, there are some exemplary regions, such as Huainan which has CEMs for particulates, SO_2 and NOx on all six power plants which provide real-time online data to the public on their emissions (APEC, 2008; Ping, 2008).

For most plants, the SO_2 emission limit is in kg/h and is based on factors such as the height of the stack, the wind speed at the exit of the stack and the emission rate of the flue gases. There is also an emission control coefficient which must be taken into account which varies with the region (lower coefficients for those plants in heavily populated areas) (APEC, 2008).

The Chinese have their own national standards for monitoring major pollutants (APEC, 2008). Particulates may be measured using optical systems, such as in the EU, or by opacity, as in the USA. The Chinese SO_2 manual standard is based on formaldehyde absorbing-pararosaniline spectrometry or fixed potential electrolysis method. However CEMs based on UV fluorescence and NDIR are being promoted. The manual standard for NOx is based on electrolysis method (HJ/T45) and the CEM standard on NDIR and chemiluminescence.

There has been a requirement since 1997 for CEMs for SO_2 and NOx on all new plants in China (built after 1 January 2004). There is also a requirement for CEMs for SO_2 on power plants in specified areas of concern (such as the Acid Rain Control Area) and on all plants fitted with FGD. CEMs for NOx are required on all units >300 MWe. CEMs are also gradually being fitted on older plants. According to a survey reviewed by APEC (2008) the first CEM system was installed in China in 1986 and since then over 400 CEMs had been installed in around 180 plants by 2004. However, at that time only 20% of the CEMs were found to be in normal operation with the majority either running irregularly or not in operation at all. At that time it was clear that there was little or no guidance (or standardisation/certification) of CEM systems and their operation. However, it is likely that the new wave of environmental action in China recently has changed this significantly.

The Chinese Ministry for Environmental Protection has been promoting the use of CEMs at coal-fired plants with the support of several non-governmental organisations and international agencies. In the past, according to Steinfeld and others (2008) although CEM systems have becoming more prevalent, the data they produce are ‘frequently dismissed as unreliable by industry insiders and government regulators alike’. However, with the new rolling plans for environmental improvement and the unprecedented rate of FGD and deNOx control under way in China, CEM systems are becoming the norm at all plants. In fact, since the introduction of emission fees relative to the amount of SO_2 emitted from plants, and savings to be made by cleaner plants, many operators may regard CEM systems as a means to ensuring that any fees are calculated from accurate emission values (Sloss, 2009b).

In May 2010 the Chinese State Council distributed a directive through MEP (Ministry of Environmental Protection) to strengthen efforts to reduce heavy metals, especially mercury. Requirements for mercury monitoring at coal-fired utilities will be introduced in China in 2011. The 12th Five-Year Plan, soon to be submitted for approval, will include the requirement for reduction of mercury at coal-fired power plants (Lee, 2010).

5.5.2 Japan

Plant efficiencies must be calculated and reported to the local regulating authority on a monthly basis.

Utilities in Japan must estimate their carbon intensity as $kgCO_2/kWh$ and report the weighted average for all their plants but the plant-specific data are not published.

Emission limits in Japan are amongst the most stringent in the world, although they are based on an individual company or plant-specific basis and are rarely published. However, a great amount of emphasis is placed on social responsibility and so some plants choose to display their emissions online to demonstrate to the public how green they are. On the whole, although most plants remain relatively secretive about their emissions, it can be assumed that the actual emissions are likely to be as low, if not lower, than those seen for equivalent sized plants in the EU or North America and it can be assumed that CEMs are standard on all coal-fired plants (Sloss, 2009b).

5.5.3 India

Indian plants are required to use power station heat rate (SHR) as a proxy for plant efficiency. The Central Electricity Authority collects data on gross electricity generation, coal consumption and average HHV. Monthly and annual heat rates are then calculated and compared with the design heat rate, or unit heat rate (UHR). Operating parameters such as fuel consumption, GCVs and gross generation are collected from each plant on a monthly basis and used to calculate the plant-specfic SHR. The performance is graded based on the UHR-SHR value. The individual plants are then split into those with 'good performance' (SHR within 10% of design) and those with 'poor performance' (SHR more than 10% outside the design values) (CIAB, 2010).

There is currently little on no legislation for SO_2 and NOx and so it can be assumed that CEM systems are not yet standard on Indian coal-fired plants.

5.5.4 Other Asia

In **Korea**, each plant has an Energy Efficiency Department which calculate's the plant efficiency based on fuel analysis (HHV) of the coal blends entering the plant. Although the data are collated they are not made available to the public (CIAB, 2010).

Indonesia established a requirement in 2008 for CO_2 monitoring and reporting at plants greater than 25 MW, based on the use of CEMs. In December 2008, new environmental regulations were introduced in Indonesia which include emission limits and emission inventory data for the major pollutants. CEMs are likely to be required on all new plants (presumably post-2008) but older plants may use manual methods or emission factors.

In the past, in the **Philippines** there has been no requirement for CEMs and monitoring was considered 'inadequate'. However, there appears to be a move towards a requirement for plant operators to monitor emissions. The 2000 Clean Air Act includes emission permits for existing and new plants and a charge system based on the amount of pollutant emitted. However, as yet, it is unclear whether this system is being applied in practice. Similarly, tightened emission standards have been introduced in **Thailand and Vietnam** in the last decade but it is unclear how these standards are being policed (APEC, 2008). As of 2008, monitoring of major pollutants was only required three or four times a year at power plants in Vietnam and there was no current emission inventory for the existing units (Sloss, 2009b).

5.6 Other

Russian Federal Law 261-FZ on Energy Conservation and Improving Energy Efficiency, 2009, requires power plants to carry out energy audits every three years. Guidelines for carrying out these audits include the use of energy efficiency indicators and rules for calculation. Each plant must meet performance standards which set the maximum allowable energy consumption per unit of electricity or heat produced (CIAB, 2010).

Emission limits for plants are set on a case-by-case basis and are reviewed annually. Actual emissions are reported either from emission factors or actual monitoring tests. There are currently no requirements for CEM systems on coal-fired plants in Russia. Reporting of emissions is performed annually by either manual methods or mass-balance calculations (Romanov, 2011).

The **South African** Department of Environmental Affairs requires Eskom, the sole coal-fired utility operating agent in the country, to report dust emissions based on opacity monitoring. The opacity monitors are calibrated every two years based on a stack mass emission test. Emission factors for

CO_2, SO_2 and NO were determined from coal analyses and emissions testing from over 60 boilers to create a database of emission factors. However, since 1994 the emission factors for CO_2 and SO_2 are calculated directly from the coal analyses. NO is calculated using a plant-specific emission factor which is re-evaluated every three years. Eskom is currently installing CEM systems to its 56 operating coal-fired stacks with all systems to be in place by 2014. These multi-gas systems will be able to measure CO_2, SO_2, NO and O_2 (Keir, 2011).

5.7 Comments

In the EU, countries must report CO_2 emissions to the EU ETS based on emission factors, unless they can demonstrate that their CEM system produces more accurate data. Conversely, in the USA, CEMs for CO_2 are encouraged over the use of emission factors. However, for all other pollutants, there appears to be general agreement that CEM systems provide more useful data than emission factors for compliance monitoring.

Although the specific legislation varies from country to country, there is a growing trend, even in China and developing Asia, to install CEM systems for at least the major pollutants (particulates, SO_2 and NOx).

6 Conclusions

Legislation and other national and international instruments designed to limit and control the atmospheric emissions of pollutants from sources such as coal-fired power stations are increasing worldwide. In order for these systems to succeed, it is necessary that emissions are measured and monitored in a reliable manner.

One of the most important factors with respect to controlling the total emissions of all pollutants from coal combustion is the total volume of coal used. Efforts to improve plant efficiencies will mean more power for less fuel and a concomitant reduction in the emissions of all pollutants. Energy efficiency is therefore gaining increasing importance in the international and national arena. There are numerous ways to calculate or estimate power plant efficiency. Unfortunately, the overlapping and mismatching systems currently in use mean that it is not often possible to compare plant efficiencies directly. Over and above this, most plants consider their exact efficiency data commercially sensitive and do not make it readily available to the public. There is therefore a trend removing the focus from the absolute values for plant efficiencies to measures for quantifying improvement in performance and towards benchmarking the best performing systems. Power plants can then work towards improving their plant efficiencies to match those of the best performing plants.

With respect to evaluating emissions of pollutants on a plant-by-plant basis, there are two major approaches – the use of emission factors (based on accumulated and averaged emissions data) and the use of actual emissions measurement systems such as manual methods or CEMs. The decision as to which method should be used is often defined within the relevant emissions regulation. Compliance monitoring requirements, to comply with set emission limits or standards, tend to require a continuous, real-time approach using CEM systems to ensure that emissions do not exceed a limit at any time. Although data are recorded and collated throughout the operation of each unit, these data are rarely used in an additive or cumulative manner to provide total emission values over an extended period of time, such as t/y. Whilst it could be possible to use some data in this way, it is often the case that the data are either not available in a usable form or are not acceptable under the requirements for inventory data. Inventory data are usually calculated in a top-down or emission factor-based manner and, in most situations, this is regarded as the most appropriate method for inventory preparation at a national or international level. But since the emission factors used for these inventories are produced and modified with actual plant-level emission measurement data, the two systems always overlap.

Standards for monitoring standard pollutants such as particulates, SO_2 and NOx are commonly defined within national or international regulations. CEN, the European Standards Committee, produces standards for emissions monitoring which are obligatory in EU member states. The US EPA produces distinct but similar standards for use in the USA. ISO, the International Standards Organisation, produces voluntary standards which may be used by countries when there are no relevant national standards available. Although these standards may vary between CEN, ISO and the US EPA, they are generally based upon the same empirical measurement principles. The accuracy and comparability of data is often hindered more by the different units of measurement used than the methods themselves.

The requirements for efficiency monitoring, emissions monitoring and estimation and compliance reporting are all specified within national legislation. Although most developed countries have similar approaches there are a few notable differences. For example, in the EU CO_2 reporting is required using emission factor calculations, unless a CEM system can be shown to provide superior data. Conversely, in the USA, CEM systems are preferred for CO_2 reporting and emission factors are only used when CEM systems are not available or operational.

For the major pollutants – particulates, SO_2 and NOx – CEM systems are standard on all plants in developed nations and are becoming increasingly common in China and other regions in Asia for compliance monitoring. However, for estimation of emissions at the national level, for reporting to national and international level, emission factors remain the method of choice.

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8 Appendices

Appendix 1 – Calculating efficiency values

(From Engineering Toolbox, 2011; and CIAB, 2010)

Heat rate

The overall thermal performance or energy efficiency for a power plant for a period can be defined as:

$$\Phi_{hr} = H/E$$

Where:

Φ_{hr} heat rate (BTU/kWh, kJ/kWh)
H heat supplied to the power plant for the period (BTU, kJ)
E energy output from the power plant for the period (kWh)

Heat rate is the quantity of heat required to produce a given output. Lower heat rates give higher % efficiencies.

$$\text{Efficiency} = 3600/\text{heat rate}$$

Where the heat rate is measured in kJ/kWh, MJ/MWh or GJ/GWh

This means that a plant with a heat rate (heat consumption rate) of 9000 kJ/kWh output has an energy efficiency of 40%.

Thermal efficiency

Thermal efficiency of a power plant can be expressed as:

$$\mu_{te} = (100)(3412.75)/\Phi$$

Where:

μ_{te} thermal efficiency (%)

Capacity factor

The capacity factor for a power plant is the ratio between average load and rated load for a period of time and can be expressed as:

$$\mu_{cf} = (100)\ P_{al}/P_{rl}$$

Where:

μ_{cf} capacity factor (%)
P_{al} average load for the power plant for a period (kW)
P_{rl} rated capacity for the power plant for a period (kW)

Load factor

The load factor for a power plant is the ratio between average load and peak load and can be expressed as:

$$\mu_{lf} = (100)\ P_{al}/P_{pl}$$

Where:

μ_{lf} load factor (%)

P_{al} average load for the power plant for a period (kW)

P_{pl} peak load for the power plant for a period (kW)

Economic efficiency

Economic efficiency is the ratio between production costs, including fuel, labour, materials and services, and energy output from the power plant for a period of time. Economic efficiency can be expressed as:

$$\Phi_{ee} = C/E$$

Where:

Φ_{ee} economic efficiency (¢/kWh, €/kWh, etc)

C production costs for a period (cents, euro, etc)

E energy output from the power plant in the period (kWh)

Operational efficiency (input/output method)

Operational efficiency is the ratio of total electricity produced by the plant during a period of time compared to the total potential electricity that could have been produced if the plant operated at 100% during the period. Operational efficiency can be expressed as:

$$\mu_{eo} = (100)\ E/E_{100\%}$$

Where:

μ_{eo} operational efficiency (%)

E energy output from the power plant in the period (kWh)

$E_{100\%}$ potential energy output from the power plant operated at 100% in the period (kWh)

Net efficiency (component method)

Boiler efficiency, ηb, is calculated as follows:

$$\eta b = (H_b - \Sigma losses)/H_b$$

Where:

ηb boiler efficiency

H_b boiler heat input (combined heat from fuel combustion and thermal input from the air heater)

Σlosses the sum of the losses, including dry gas loss, moisture in air and coal, unburnt combustible content, incomplete combustion, heat of ash, radiation heat loss from the boiler and other loss

Plant efficiency is then:

$$\eta p = \eta b \times \eta t \times (1 - P_{loss})$$

Where:

ηp overall plant efficiency

ηb boiler efficiency (see above)

ηt turbine efficiency (inverse of turbine heat rate, characteristic of the equipment used)

P_{loss} plant loss, including pressure losses in pipes, mechanical losses and power consumed by auxiliary equipment, expressed as a percentage of boiler heat input

Appendix 2 – Calculating emission factors

First, the mass emission rate (m, as total mass per defined time period) can be calculated as follows:

$$m = C \times V$$

Where:
C average mass concentration (in the flue gas, as measured)
V volumetric flow rate (amount of flue gas over time)

The average mass concentration in the flue gas would commonly be obtained from CEM data at the study plant, although manual monitoring during representative operating conditions can still be of value.

The value for V can be obtained from flue gas flow monitoring devices but, for sources such as large coal-fired plants, the flow rate is considered to be relatively uniform. For countries such as the UK, there may be representative flow factors available based on measurements at representative plants. These should be used, if available. Individual sites may also calculate site-specific flue gas flows for each fuel, based on the actual fuel compositions used during the year in question. This would involve calculating flue gas volumes based on first principles – gas composition, pressure, temperature and so on. Alternatively, average flow rates can be calculated as follows:

flue gas flow rate (coal) = 9000 m^3/t as-received fuel (dry gas, 6% O_2)
or
364 m^3/GJ (NCV, net calorific value)

The mass emission rate can then be used to produce an emission factor (EF):

$$EF = m/A$$

Where:
m mass emission rate, as calculated above
A value of activity data (for example, tonnes of fuel use, GWh)

Emission factors calculated from actual emission values must be calculated taking into account the wet/dry basis of the flue gas, the units used (ppm or mass volume) and are commonly normalised to a standard O_2 concentration (3%, 6% or 15%). The specific flue gas volume (SFV) represents the specific dry gas flow of the fuel at a reference oxygen concentration. The SFV can be calculated from actual fuel analysis data but varies only slightly between fuels and so a reference value is commonly used. A typical SFV value for coal (at 6% O_2) would be 350 m^3/GJ, (where N means 1013 kPa and 0°C).

The following equation is used to produce an emission factor from a known flue gas concentration (such as from a measurement study or CEM device output) (Eurelectric, 2008):

$$EF = C \times SFV/1000$$

The emission factor, in g/GJ, is produced by multiplying the specific flue gas volume, as discussed above (m^3/GJ), by the C, the concentration of the species in the dry flue gas at reference oxygen content (mg/m^3).

For fuel such as coal, the net calorific value of the coal or the specific flue gas volume must be known. Ideally, each operator would produce an emission factor based on the actual, known, calorific value of the fuel combusted at the facility. Often this type of information is available from the coal supplier but, in the absence of this, default values can be used. Ash and water contents of fuels must also be taken into account when estimating actual coal use. However, since these can vary significantly from fuel to fuel, no default values are recommended (Eurelectric, 2008).

The USA commonly uses the Gross Calorific Value (GCV; or Higher Heating Value, HHV) for a fuel, whilst in Europe the Net Calorific Value (NCV; or Lower Heating Value, LHV) is used. It is possible to convert NCV from GCV using an approximation calculation as follows (Eurelectric, 2008):

$$NCV = GCV \times f_{H_2O}$$

f_{H_2O} is the correction value for the heat of vaporisation of the water in the fuel. For coal the f_{H_2O} value is 0.95.

NCV values can be taken from reference tables such as those provided by the IPCC guidelines. Typical values are 25.8 GJ/t for bituminous coal, 32.5 GJ/t for petroleum coke, 26.7 GJ/t for anthracite, 18.9 GJ/t for subbituminous coal and 11.9 GJ/t for lignite.

In some cases emission rates are needed which include a time factor. For example, the guidelines for reporting emissions under the Australian National Pollutant Inventory (NPI) include details of how to estimate the emissions of a substance as an hourly value. The example below is for particulate emissions (AG, 2008):

$$E_{PM} = C_{PM} \times Q_d \times 3.6\ [273/(273+T)]$$

Where:
E_{PM} hourly emissions of particulate matter, kg/h
C_{PM} concentration of particulate matter, g/m^3
Q_d stack gas volumetric flow rate, m^3/s, dry
3.6 3600 seconds per hour, multiplied by 0.001 kg/g
273 273 K (0°C)
T temperature of gas sample, °C

If the stack gas is wet, then the equation must be adjusted as follows:

$$E_{PM} = Q_w \times C_{PM} \times 3.6 \times (1\text{-moist}_R/100) \times [273/(273+T)]$$

Where:
Q_w wet cubic metres of exhaust gas per second, m^3/s
moist_R moisture content, %

The hourly emission rate can then be used in a similar way to an emission factor to give a basic value for emissions that can be multiplied by an activity value (in this case, the total time period) to give total emission values.

Appendix 3 – CEN and ISO monitoring standards relevant to emissions from coal-fired plants (Curtis, 2011)

Monitoring plans:

EN 15259	Requirements for measurement sections and sites and for the measurement objective, plan and report

Alternative methods:

EN/TS 14793	Intralaboratory validation procedure for an alternative method compared to a reference method

CEMs:

ISO 10396	Sampling for automated determination of gas emission concentrations for permanently installed monitoring systems (CEMs)
EN 14181	Quality assurance of an AMS (automated measuring system/CEM)
EN 15267-1	Certification of automated measuring systems – Part 1. General principles
EN 15267-2	Certification of automated measuring systems – Part 2. Initial assessment of the AMS manufacturer's quality management system and post certification surveillance for the manufacturing process
EN 15267-3	Certification of automated measuring systems – Part 3. Performance specifications and test procedures for automated measuring systems

Flow:

ISO 14164	Determination of the volume flowrate of gas streams in ducts – automated method

Basic gas components:

EN 14790	Determination of the water vapour in ducts
EN 14789	Determination of volume concentration of oxygen (O_2). Reference method – paramagnetism
EN 15058	Determination of the mass concentration of carbon monoxide (CO). Reference method: NDIR
ISO 12039:	Determination of CO, CO_2 and O_2 – performance characteristics and calibration of an automated measurement system.

Particulates:

EN 15859	Certification of automated dust arrestment plant monitors – performance criteria and test procedures
ISO 9096	Manual determination of mass concentration of particulate matter
ISO 12141	Determination of mass concentration of particulate matter (dust) at low concentrations. Manual gravimetric method
ISO 10155	Automated monitoring of mass concentrations of particles. Performance characteristics, test methods and specifications

EN 13284-1	Determination of low range mass concentration of dust. Manual gravimetric method
EN 13284-2	Determination of low range mass concentration of dust. Automated measuring systems

SO_2:

EN 14791	Determination of mass concentration of sulphur dioxide. Reference method
ISO 7934	Determination of the mass concentration of SO_2 – hydrogen peroxide/bariumperchlorate/thorin method
ISO 11632	Determination of mass concentration of SO_2 – ion chromatography method
ISO 7935	Determination of the mass concentration of SO_2 – performance characteristics of automated measurement methods/CEMs

NOx:

EN 14792	Determination of mass concentration of nitrogen oxides (NOx). Reference method: chemiluminescence
ISO 11564	Determination of the mass concentration of nitrogen oxides – naphthylethylenediamine photometric method
ISO 10489	Determination of the mass concentration of nitrogen oxides – performance characteristics of automated measurement systems.

Halogens:

EN 1911	Manual method for determination of HCl – ion exchange chromatography
ISO 15713	Sampling and determination of gaseous fluoride content – ion exchange chromatography

Organics:

EN 12619	Determination of the mass concentration of total gaseous organic carbon at low concentrations in flue gases. Continuous flame ionisation detector method
EN 13649	Determination of the mass concentration of individual gaseous organic compounds. Activated carbon and solvent desorption method
ISO 11338-1	Determination of gas and particle-phase polycyclic aromatic hydrocarbons. Sampling
ISO 11338-2	Determination of gas and particle-phase polycyclic aromatic hydrocarbons. Sample preparation, clean-up and determination
EN 1948-1	Determination of the mass concentration of PCDDs/PCDFs and dioxin-like PCBs - sampling
EN 1948-2	Determination of the mass concentration of PCDDs/PCDFs and dioxin-like PCBs - extraction and cleaning of sample
EN 1948-3	Determination of the mass concentration of PCDDs/PCDFs and dioxin-like PCBs - identification and quantification
EN 1948-4	Determination of the mass concentration of PCDDs/PCDFs and dioxin-like PCBs – sampling and analysis of dioxin-like PCBs

Mercury:

EN 13211 Manual method for determination of the concentration of total mercury

EN 14884 Determination of total mercury – automated measurement systems/CEMs

EN 14385 Determination of the total emissions of As, Cd, Cr, Co, Cu, Mn, Ni, Pb, Sb, Tl and V

Fine particulates, $PM_{10/2.5}$

EN/ISO 23210 Stationary source emissions – determination of $PM_{10/2.5}$ mass concentration in flue gas – measurement at low concentrations by use of impactors

Standards currently under development:

CEN methods:

WG23 CEN Manual and automatic measurement of velocity and volumetric flow in ducts
Standard at the committee draft stage

ISO methods:

WG20 ISO/CD 13271 – determination of $PM_{10/2.5}$ using virtual impactors
Standard at the committee draft stage

WG21 ISO/WD 25597 – determination of $PM_{10/2.5}$ using cyclone samplers and sample dilution
Standard at the working draft stage

WG22 ISO/FDIS 25139 – determination of methane using gas chromatography
Standard at the voting stage

WG25 ISO/WD 14385-1 – GHG – calibration of AMS/CEMs

ISO/WD 14385-2 – GHG – QA/QC of AMS/CEMs
Standard at the working draft stage

WG26 ISO/CD 13833 – determination of the ratio of biomass (biogenic) and fossil-derived CO_2 – radiocarbon sampling and determination