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# Upgrading and efficiency improvement in coal-fired power plants

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## **Abstract**

Improving the efficiencies of the large number of older coal-fired power plants operating around the world would give major savings in CO<sub>2</sub> emissions together with significant other benefits. This report begins with a summary of the ways efficiency can become degraded and of the means available to combat the decrease in performance. These include improvements to operating and maintenance practices and more major techniques that are available, including boiler and turbine retrofits. There is also an update on fuel drying developments as a route to higher efficiency in plants firing high moisture lignites. The largest chapter of the report contains a number of descriptions of case study improvement projects, to illustrate measures that have been applied, benefits that have been achieved and identify best practices, which are summarised. Major national and international upgrading programmes are described.

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## Acronyms and abbreviations

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APEC	Asia-Pacific Economic Cooperation
APP	Asia-Pacific Partnership on Clean Development and Climate
A-USC	advanced ultra-supercritical
BMCR	boiler maximum continuous rating
CEA	Central Electricity Authority (India)
CEM	Clean Energy Ministerial
CenPEEP	Centre for Power Efficiency and Environmental Protection (India)
ECPG	Energy Conservation Power Generation (scheduling program on trials in China)
EEO	Energy Efficiency Opportunities Program (Australia)
ESP	electrostatic precipitator
EU	European Union
FEED	front end engineering and design
FGD	flue gas desulphurisation
FGET	furnace gas exit temperature
GSEP	Global Superior Energy Performance Partnership
GW	gigawatts
HHV	higher heating value
HP	high pressure
IEA	International Energy Agency
IEA CCC	IEA Clean Coal Centre
IED	Industrial emissions directive (EU)
IP	intermediate pressure
kPa	kilopascals
kWh	kilowatt hours
LCPD	Large Combustion Plant Directive (EU)
LHV	lower heating value
LP	low pressure
MCR	maximum continuous rating
MPa	megapascals
MW	megawatts
OECD	Organisation for Economic Cooperation and Development
OEM	original equipment manufacturer
O&M	operation and maintenance
PCC	pulverised coal combustion
PLF	plant load factor (India)
PRB	Powder River Basin (USA)
RLA	residual life assessment
R&M	renovation and modernisation
SAARC	South Asian Association for Regional Cooperation
SC	supercritical
SCR	selective catalytic reduction
tce	tonnes of coal equivalent
TP	thermal plant (India)
USAID	United States Agency for International Development
USC	ultra-supercritical
US DOE	US Department of Energy
VHP	very high pressure

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# I Introduction

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The efficiencies of coal-fired plants will normally decrease over time as components suffer deterioration with age and use. The losses that develop in the earlier part of the life of a plant are generally containable by employing good operating and maintenance practices. However, after about 25–30 years of operation, performance and reliability will usually have decreased to the extent that substantial works, known as retrofits, may be merited, in order that the unit may be restored to operating efficiently and economically. The latter offer opportunities to incorporate technology advances made in the period since the unit was built. Despite involving substantial outlay (typically US\$100–200 million), retrofits will provide a payback in restored generation, fuel saving, extended plant life, and, in some countries, CO<sub>2</sub> emissions cost savings. There are also benefits of reduced specific emissions of other pollutants. Retrofits are the main subject of this report.

Lower efficiencies result in more CO<sub>2</sub> being emitted per unit of electricity supplied and there is a large number of older coal-fired power plants worldwide that could potentially be retrofitted to give major reductions (hundreds of Mt/y) in CO<sub>2</sub> emissions (Henderson and Baruya, 2012).

In a significant number of (typically OECD) countries, efficiency improvement activities have been given a high priority to minimise fuel costs and emissions. Turbine retrofits are especially worthwhile as advanced design features can be incorporated, although, potentially, all areas of plants may be improvable to restore performance. For example, boiler improvements are sometimes needed where there has been a major change in the coal. Major plant upgrading involving conversion of subcritical to supercritical or ultra-supercritical (USC) could raise the thermal efficiency more substantially but has seldom progressed beyond studies because of the high cost.

In some other (typically less developed) countries, while the technical challenges may be broadly similar, there can be a number of factors that can cause the performance decline to be greater. These include restricted resources, lack of skills, pressure to keep online because of power capacity shortages, and, in some cases, having to burn particularly difficult coals. These factors can mean that boiler-related improvements are usually needed as well as turbine works. Where coal quality is relevant, it is possible in some cases to improve it, but this report does not include coal washing as a route to efficiency improvement. For the latter, the reader is referred to IEA Clean Coal Centre reports by Henderson (2003), Adams (2009) and Couch (2002), because comparatively little has changed with respect to conventional coal washing. This report does however include recent developments in lignite drying (*see* Chapter 3).

Other IEA Clean Coal Centre reports have described the issues and principles associated with efficiency losses and means that are available for correcting them at coal power plants (Henderson, 2003; Adams, 2009). An APEC (Asia-Pacific Economic Cooperation) report has identified sources of inefficiencies in older coal-fired power generation plants in the Asia-Pacific region (Boncimino and others, 2005). Section 2.1 provides a reminder of these aspects, and the remainder of Chapter 2 outlines the improvement measures that are often appropriate for turbines to make their designs close to those of the more efficient new systems.

Table 1, from a report by the US DOE's National Energy Technology Laboratory shows the potential increase in plant net efficiencies (HHV basis, but these would be very close to LHV based gains also) that could come from plant improvements in the USA (Nichols and others, 2008). Note that at any given plant, not all the measures are applicable, and the entries may not be totally independent, and so total achievable gains will be less than the sum of the final column of values. A table from an APEC study is reproduced as Table 2 (Boncimino and others, 2005). This indicates that a typical overall efficiency improvement of 3.5 percentage points (again on an HHV basis, but very close to LHV based gains) could conservatively be expected from major retrofits of plants as shown in the APEC

<b>Table 1 Potential efficiency improvements for power plants in the USA</b> (Nichols and others, 2008)	
Area of improvement	Efficiency increase, percentage points
Air heaters (optimise)	0.16–1.5
Ash removal system (replace)	0.1
Boiler (increase air heater surface)	2.1
Combustion system (optimise)	0.15–0.84
Condenser (optimise)	0.7–2.4
Cooling system performance (upgrade)	0.2–1
Feedwater heaters (optimise)	0.2–2
Flue gas moisture recovery	0.3–0.65
Flue gas heat recovery	0.3–1.5
Coal drying (installation)	0.1–1.7
Process controls (installation/improvement)	0.2–2
Reduction of slag and furnace fouling (magnesium hydroxide injection)	0.4
Sootblower optimisation	0.1–0.65
Steam leaks (reduce)	1.1
Steam turbine (refurbish)	0.84–2.6

<b>Table 2 Potential efficiency increases from plant improvements in APEC countries</b> (Boncimino and others, 2005)		
Category	Area of improvement	Net efficiency gain, (percentage points)
Combustion system	Pulveriser and feeder upgrades	0.3
	Air heater repair or upgrade	0.25
	Sootblower improvements	0.35
	Excess air instrumentation & control	0.2
Steam cycle	Feedwater heater repairs	0.4
	Heat transfer tube upgrades	0.6
	Steam turbine blades	0.5
	Cycle isolation	0.5
	Condenser repairs	0.4
O&M	O&M training	
	Computerised maintenance and management systems and reliability centred maintenance	Included in combustion and steam cycle gains. Efficient operation realised over the long term
	Distributed control systems	
Combined total		3.5

Region. The gains from applying some of these measures (such as modern turbine blades) could be considerably more, but it is important to note that the realisable efficiency will be site-specific. For example, the maximum achievable efficiency will be lower in a warm location than in a cooler location because of available heat rejection temperatures.

Improving the technology is not the whole solution. In order that *sustainable* improvement occurs, future management of plant maintenance and operation needs to be effective. Otherwise, inappropriate operating conditions, which themselves affect performance, can lead to deterioration in components and further efficiency loss. Programmes and projects to address these issues are also discussed. Plant improvement naturally has to form part of an overall policy involving closure of uneconomic plants and new-builds, with, ultimately, adoption of CO<sub>2</sub> capture and storage.

This report is structured as follows. In Chapter 2, there is a reminder of the ways efficiency can become degraded and of the means available to combat the decrease in performance, including improvements to operating and maintenance practices and more major techniques that are available (retrofits). Chapter 3 describes lignite drying developments. Chapter 4 describes upgrades to higher steam conditions that have been suggested as major projects. Chapter 5 describes a number of example improvement projects, to illustrate measures that have been applied, benefits that have been achieved and identify best practices. Chapter 6 describes some major upgrading programmes. Chapter 7 develops a list of best practices. Chapter 8 presents the summary and main conclusions from this review.

## 2 Efficiency maintenance and improvement – principles

Figure 1 shows the main locations of efficiency losses on a PC boiler-turbine unit [losses from SCR (selective catalytic reduction) and FGD (flue gas desulphurisation) treatment systems are not included in this report]. The operational and maintenance (O&M) issues are described briefly in Section 2.1, and much more detailed descriptions on those aspects can be found in other IEA Clean Coal Centre reports (Henderson, 2003; Fleming and Foster, 2001). Chapter 7 of this report brings together a summary of best practices for upgrading and efficiency improvement, including through good O&M practices and retrofitting.

The key to maintaining maximum efficiency is to monitor all the sources of energy losses on a continuing basis and to control these by appropriate measures. These include a combination of well managed operation, properly managed preventive maintenance based on sound data and predictive techniques, and, if necessary, efficiently executed breakdown repairs. Maintenance regimes and planned outages need to be designed to keep forced outage rates at acceptable levels. The efficiency and performance of turbines need to be assessed periodically to identify areas for attention. Rated steam parameters need to be maintained. After about 30 years, when efficiency and reliability have declined significantly, it becomes economically worthwhile to consider more extensive modernising works such as turbine retrofits and boiler improvements. The latter are the principal concern of this report and are introduced in Section 2.2.

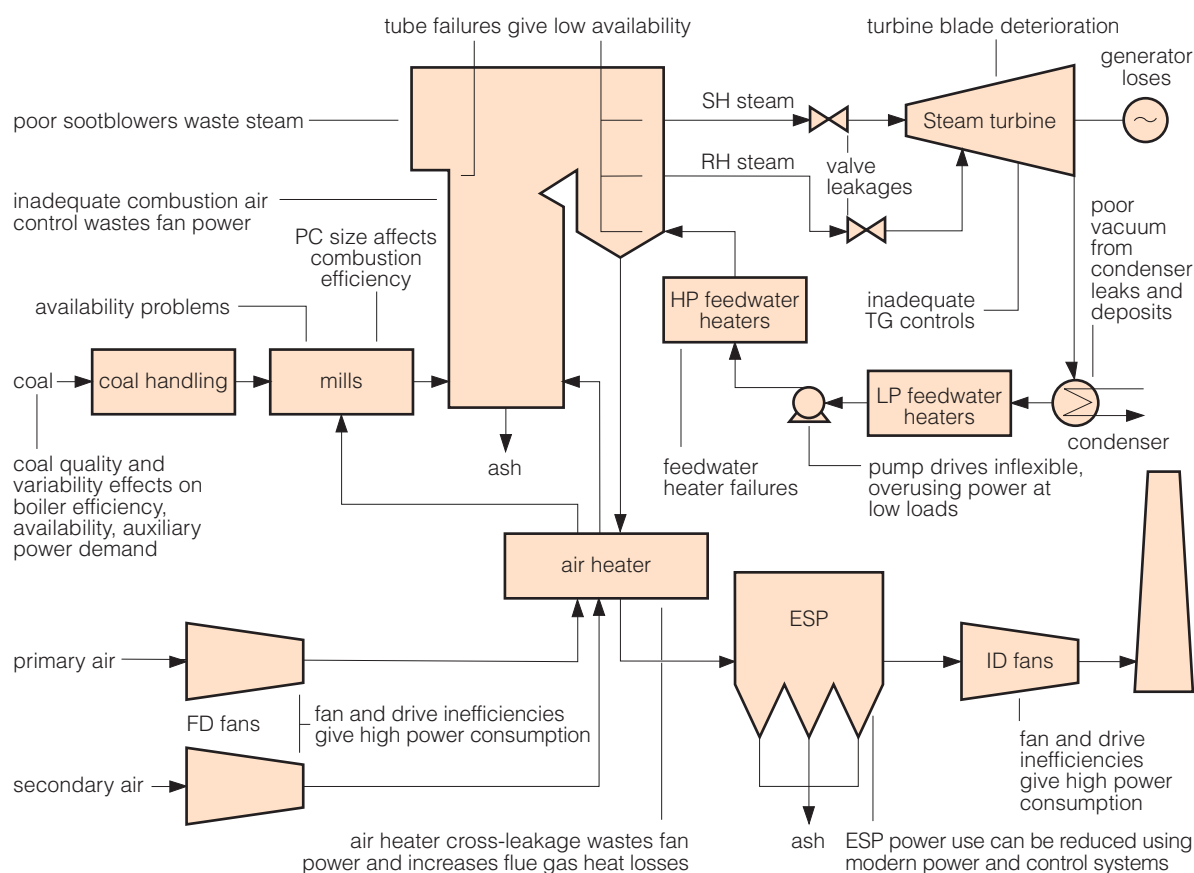


Figure 1 Areas of a PCC unit that can give rise to efficiency loss (Henderson, 2003)



## 2.1 Operation and maintenance

There are many mechanisms through which plant performance can be degraded as a result of poor operation and maintenance. Examples are poor combustion efficiency from incorrect fuel/air mixing, excessive radiative losses from damaged insulation, high flue gas heat losses from incorrect heat balances and high exit temperatures, inefficient heat transfer to fouled boiler surfaces, boiler tube failures due to fouling, corrosion or poor monitoring, air infiltration from insecure access doors, high leakage across rotary air heaters, high auxiliary power consumption and even damage to turbines. Current maintenance philosophies in OECD countries include both breakdown and planned maintenance, but a lack of money for carrying out routine maintenance in developing countries can lead to too much reliance on breakdown maintenance. Certain plant equipment areas require timely preventive maintenance for high availability.

During operation, fuel distribution to the burners fed by each mill should be even to obtain good combustion efficiency and minimise NO<sub>x</sub> and CO emissions. The CO level is the most reliable guide to optimum combustion for input to control systems. Monitoring excess oxygen levels provides a measure of air in-leakage and air heater cross leakage. Target cross-leakages of 8% and 12% have been suggested for bi-sector and tri-sector designs, respectively, to minimise fan power and flue gas heat losses.

Boiler efficiency management involves both performance monitoring and testing. Regular boiler inspections should include visual checks of combustion in the furnace, casing and ductwork condition and the closure of observation doors. Because slagging and fouling obscure surfaces, boiler cleaning effectiveness has a major influence on the efficiency of the plant. Slagging can result in tube failure, but creep, fatigue and erosion contribute to 60% of tube failures. Repeated incidences can indicate lack of observance of correct O&M practices, lack of proper failure analysis, wrong preventive actions, or absence of a suitable failure reporting and monitoring system. An example of correct O&M practice is strict adherence to water quality limits and oxygen levels.

Minimising the leakage of air into the condenser is important for maintaining adequate vacuum, as also is maintenance and water quality (poor water quality can cause fouling of tube surfaces and so poorer heat transfer).

Control systems are replaced a number of times during the life of most plants in OECD countries. Efficiency can be increased by the order of a percentage point. Routine tasks involved in start-up and shut-down and part load operation at European power plants are automated.

## 2.2 Plant retrofits

### 2.2.1 Turbine upgrades

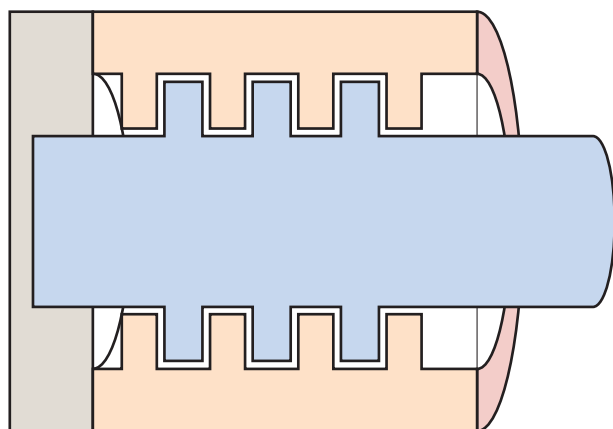
Various components and systems have been developed by all the steam turbine suppliers to raise the efficiency and reliability of new turbines. These design features are also offered for retrofitting to older turbines to bring their performance up to close to that of modern ones. While there are differences between the suppliers in precise engineering implementation, the basic approaches offered and applied by all suppliers are similar. Projects implemented using these techniques by different companies are included in the case studies in Chapter 5.

Turbine-related improvement technologies often offered are:

- advanced sealing (shaft and blading);
- major upgrading, involving fitting new blades with advanced profiles, replacement inner casings, replacement steam valves;
- condenser optimisations – reconfiguring, tube replacement.

## Advanced sealing

Labyrinth seals are conventionally used to prevent steam leakage along the shaft (*see* Figure 2), for example along the section of shaft between the high pressure (HP) and low pressure (LP) turbine in



**Figure 2** Conventional labyrinth seal on turbine shaft



**Figure 3** Siemens segmented labyrinth seal employing coil springs (Smiarowski and others, 2005)

1.5% to 3% of hot reheat flow, can deteriorate to as much as 12–16% as the turbine ages (Foley, 2010a). Careful performance testing is needed to identify the precise area where steam loss is occurring, but after this, the appropriate combination of seals can be engineered to address the problem. These are then applied at the next outage, when the inner casing has been opened. It has been shown that the internal leakage can be reduced to 3–5% by applying means such as restoring correct clearances, replacing attachments and enhancing packing. Detailed examples of such enhancements have been described by Foley (2010b), and one of the case studies describes another (*see* Section 5.16).

Leakage losses occur when steam bypasses a stage by leaking past the tips of stationary and moving blades. The clearances increase as plants age. With older impulse turbine designs, most of the potential loss area can be between the diaphragms – the partitions that hold the fixed blades – and the shaft, for which labyrinth seals and modifications of these that are used are described above. Leakage

combined systems or where the shaft passes through the casing.

They provide non-contact sealing action by controlling the passage of the steam through a variety of chambers. One means to improve the seal is to apply a spray-abradable coating to reduce the tip clearances. Besides giving a 0.1–0.2% improvement in turbine performance, there are operational benefits in the event of a rub, in that the sharp edge of the shaft seals will suffer minimal wear during contact with the softer coating.

In order to accommodate expansion arising from temperature changes, the labyrinth seals in a steam turbine are normally made up of segments mounted around the shaft, maintained in position by radial flat springs. Changing to a retractable system can avoid damage caused by thermal expansion and vibration. Figure 3 shows coil springs placed between the segments to enlarge shaft clearances during start-up to achieve this. At steady state condition, high pressure steam enters the ring segments to restore design clearance (Strunk and Kundu, 2012). Brush seals can be used to give zero clearance to further increase performance.

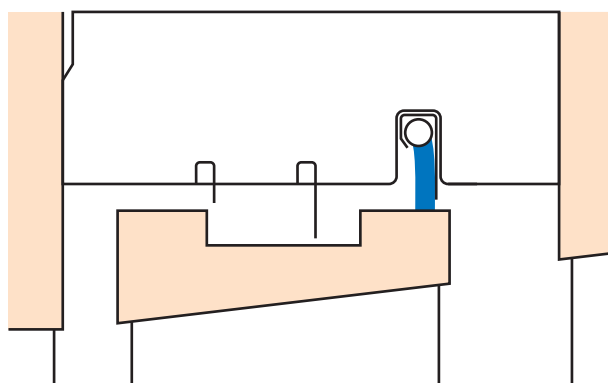
Excessive internal leakage of steam within combined HP/IP units from the HP section to the IP (intermediate pressure) section is a known cause of degradation in performance. TurboCare (a network of companies providing maintenance support to operators of turbines), has found that the design leakage from the HP section to the IP section, generally around



**Figure 4 Turbine blades with shrouding** (Strunk and Kundu, 2012)



**Figure 5 Brush seals in blade path** (Strunk and Kundu, 2012)



around moving or fixed blades in modern reaction designs is minimised through use of shrouding or covers on the ends of the blades and with brush sealing (see Figures 4 and 5 for examples). Shrouding also provides support to the blade tips.

### Blades, rotor and inner casing replacement

Even some years ago, replacement of LP turbine blades with newer designs enabled significant efficiency gains (Henderson, 2003). But over the last ten years or so, designs of HP and IP turbine systems have now also improved greatly. With the continued developments in 3D blade designs by major manufacturers such as Alstom, Siemens, MHI, GE and Hitachi, high pressure and intermediate pressure turbine sections can be upgraded very significantly by replacing selected blade rows with the advanced blades.

It is now not uncommon to see all or much of the steam turbine systems in plants of 30 years or more age in OECD countries being retrofitted with modern design components. This option, most widely adopted at long-life plants, involves reconstruction of the turbine to have entirely new internals including shaft, blading and seals. Inner casings will frequently be replaced as well as valves and, sometimes, the condenser. This approach improves reliability and performance, reduces maintenance requirements, and ensures a life extension for the turbine. It may also increase output from the same steam flow. It can also increase flexibility, which is becoming increasingly important as fossil-fuelled plants have to compensate for widely varying output from renewable power sources – see a recent IEA Clean Coal Centre report by Mills (2011). A typical major turbine retrofit may add up to 40 MW to the output of a medium-sized unit at a cost of \$75 million (Power Engineering International, 2011). Once a detailed execution plan has been developed, the works can be done in around two months during a planned outage. Boiler improvements and other works such as control systems upgrades (see for

*example*, another IEA Clean Coal Centre report: Nalbandian, 2004) can be carried out at the same time. Some existing equipment may be retained to reduce the cost: these may be bearings, bearing pedestals, outer casings, piping and supports. Example projects are described in Chapter 5.

Alstom's experience is that heat rate improvements of 2–4% can be achieved in LP turbines by

retrofitting improved fixed and rotating blade profiles, better sealing technology, longer last stage blades and improved exhaust hood designs. It is also possible to raise the efficiency of HP units by using better blading and sealing to gain 12 MW on a 660 MW unit (McCoach, 2004). This is equivalent to almost a 2% improvement in efficiency. So a 1–1.5% point improvement in overall plant efficiency can be expected from such measures. Modern upgraded steam valve designs will give benefits of reduced pressure drop, high reliability in cycling and creep-resistant casings (Davies, 2013).

GE also carry out turbine upgrades where greater numbers of stages with new blade profiles are introduced to the HP and IP turbines, with improved sealing, while retaining the original outer casing – GE refers to this as Dense Pack replacement (Lesiuk, 2000; Hansen, 2008). The improved rotor and stator blades and smaller replacement rotor diameter are stated to have an attendant benefit of reducing solid particle erosion, and this, together with the use of a solid, rather than hollow, rotor (as Siemens supply also), is said to lead to a good retention of the improved efficiency and interval between inspections of at least ten years, with accompanying economic benefits.

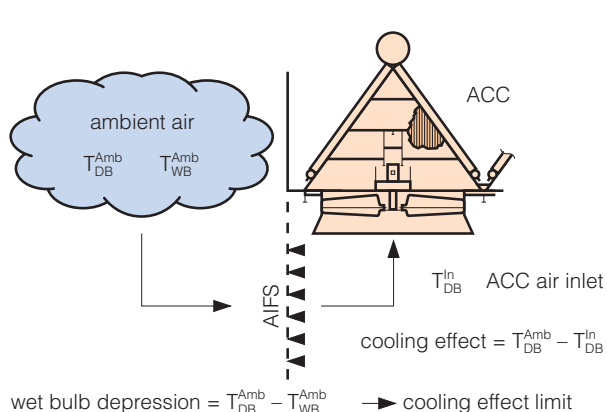
Similarly, MHI and Hitachi also apply improved blading and sealing to provide upgrades that can bring performance close to that of newly-supplied turbines (Hansen, 2008).

## 2.2.2 Condenser optimisation

Another factor that can limit performance is the condition of the condenser. Work may be required to correct air in-leakage, improve flow or clean or replace corroded or fouled tubing. Measures may range from simply reconfiguring the existing tubes to condenser replacement (Smiarowski and others, 2005).

Condenser improvements will result in a better vacuum (lower LP turbine outlet pressure), restoring power output, even to the point of allowing the possibility of modifying the LP turbine for higher output. Additionally, new materials that are used for replacement tube bundles, such as titanium and stainless steel, will give maintenance, reliability, and availability benefits because of reduced corrosion and erosion and reduced cooling water in-leakages.

## 2.2.3 Increasing capacity and efficiency of air-cooled condensers



**Figure 6** Air inlet fogging system for air cooled condensers (de Backer, 2010)

At generating plants using direct air cooling in A-frame condensers, efficiency is limited by the approach temperatures that can be achieved, which limit turbine exhaust pressure. Couch has described such systems in an IEA Clean Coal Centre report (Couch, 2005). During hot weather, efficiency and output can be particularly adversely affected. However, it is possible partially to offset this effect at such times by cooling the air stream through injection of fine water sprays that evaporate before reaching the base of the condenser.

Ambient relative humidity needs to be low for maximum effect. De Backer (2010) has

described the system offered by GEA (*see* Figure 6). He showed that a condenser pressure improvement of 6.9 cm of mercury (9.1 kPa) can be expected when spraying at an ambient temperature of 37.8°C and relative humidity of 20%. While additional potential savings in condenser size and so power demand would be available in new plants, such fogging systems could be retrofitted to provide a worthwhile upgrade in efficiency and output during hot, dry weather.

The 9.1 kPa difference in vacuum would give an approximate 3% decrease in heat rate, or more than a percentage point gain in efficiency. In cases of an existing air-cooled condenser having been degraded through accumulation of deposits on the exterior of the cooling tubes, an effective means to restore performance is to clean off the deposits through water jetting or chemical cleaning (GEA, 2008). There are other systems for introduction of water, for example hybrid towers, which incorporate water sprays in their design for spraying directly onto the tubes (Couch, 2005).

## 2.2.4 Boiler improvements

Unless there has been a major change from the design coal to a lower quality (for example, high ash or highly slagging) coal, the boiler may not be the major source of the performance loss over time in a well-maintained plant. However, advances in design have occurred and it is not unusual to need boiler modifications. Boiler modifications may also be needed to increase output further, as at Heilbron in Germany (*see* Section 5.8). In the boilers of units in some countries, where the plant may have had to be kept in service beyond its design life or operated with less than ideal maintenance because of little opportunity or insufficient available resources, the boiler and its associated systems including the coal milling and draught systems will generally require considerable improvement works. Where, additionally, coal qualities are challenging, as in India or South Africa or parts of China, this aspect compounds the problem. Changing from bituminous coals to subbituminous PRB slagging coals in the USA has necessitated substantial boiler modifications to restore output. Examples are given in Section 5.12 (J H Campbell Unit 3) and 5.13 (Comanche Unit 1). Other examples of boiler improvement works, including replacement or augmentation of heat transfer surfaces, that have provided a substantial increase in output are the retrofit projects at Arnot in South Africa and Suralaya Power Plant, Indonesia, described in Sections 5.1 and 5.2.

While the last two examples above involved significant contributions to performance from increasing the area of some of the boilers' heat transfer surfaces, optimisation of the combustion process alone can give significant benefits in efficiency and costs. Monitoring coal milling fineness and optimum distribution to the burners is a normal part of good operating practice, but modern systems of fuel and air feed monitoring and management are capable of offering significant further gains. For example, Progress Energy has partnered with Combustion Technologies (CT) and Air Monitor Corporation (AMC) to implement combustion optimisation projects at power plants in the USA to reduce emissions and increase efficiencies. Projects at eight coal-fired plants have each produced favourable results. A recent installation of this Continuous Combustion Management system (CCM) at Progress Energy's Crystal River Power Plant in Crystal River, FL, USA, to improve coal and secondary air flow balance gave a 0.5% increase in boiler efficiency and fan power savings (Estrada and others, 2010). Some of the case studies in Chapter 5 include combustion improvement through upgrading the PC mills or installing more contemporary burners, for efficiency improvement, output increase, reduced emissions of NO<sub>x</sub>, or all three.

HRL Technology (HRLT) has developed a system for cost benefit analysis of combustion optimisation measures, in which station data are complemented with measurements and thermodynamic and combustion fluid dynamic models (Korbee, 2012). Thus, measurements would be available of the fuel feed rate from each pulveriser, primary and secondary air flow rates and temperature, furnace pressure, and flue gas residual oxygen concentration, while the additional measurements may be of carbon-in-ash, furnace gas exit temperature, fuel composition and fineness, fuel and air distribution, burner performance (stability, CO/NO<sub>x</sub>, air/fuel ratio) and residual carbon. Using this information, the combustion process can be well characterised then optimised. The gain may be typically 0.1–0.15 percentage points in boiler efficiency (about 0.1–0.15% of fuel saved) and 1000 A\$/y per MW of capacity, according to HRLT. Although better availability and life extension are well-known benefits of turbine and boiler surfaces improvements, HRLT believe that combustion optimisation can give analogous attendant gains that could be as much as an order-of-magnitude higher than the commonly perceived direct economic gain of the performance improvement (Korbee, 2012).

As alluded to earlier, improvements in boiler efficiency can be achieved in parallel with other improvements, for example, reductions in primary NO<sub>x</sub> production by fitting of replacement burners and new air supply arrangements. Siemens have demonstrated this at a 550 MW plant which before the modification had primary NO<sub>x</sub> levels of 1200 mg/m<sup>3</sup> (Thierbach and others, 2012). Apart from reducing the NO<sub>x</sub> production, objectives included reducing the excess air levels, increasing the boiler efficiency, and reducing the carbon-in-ash levels. Originally designed for anthracite combustion, the coal feeding arrangements were changed, replacement burners installed, side wall air nozzles added (to reduce CO corrosion of walls) and overfire air systems added to increase the air staging in the boiler. The CO<sub>2</sub> emissions were reduced by 2.33 t/h while NO<sub>x</sub> emissions fell dramatically from 1200 mg/m<sup>3</sup> to around 300 mg/m<sup>3</sup> (at 6% O<sub>2</sub>). Other gains were:

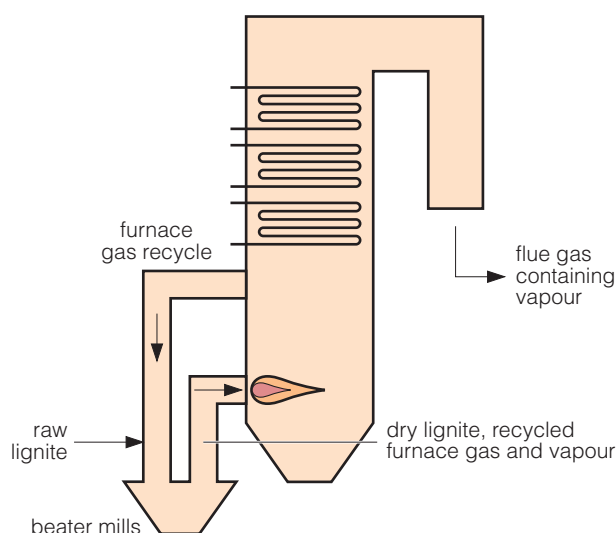
- excess air reduced from 25% to 18%;
- boiler efficiency increased by 0.42%;
- fan power consumption reduced by 900 kW;
- results confirmed on coals from six countries.

### 2.2.5 Other improvements

A previous IEA Clean Coal Centre report (Henderson, 2003) discussed other areas of plant that can deteriorate over time. An example is HP feedwater heaters, which are sometimes taken out of service if they develop leaks and resources are not available for repairs, as can happen, for example, in India. These feedwater heaters play an important role in maximising steam cycle efficiency, and the plant performance will suffer. There may be opportunity for HP heater replacements in well-maintained plants also, as at STEAG's Lünen plant in Germany. Here, installing new ones enabled full advantage to be taken of a replacement HP turbine by optimising the bleed steam pressures (Kempken and others, 2012).

### 3 Lignite drying

Lignites with inherent moisture contents of 30–65% are used for a substantial amount of power generation in countries such as the USA, Germany and Australia. The pulverised coal systems



high grade heat (furnace gas at 1000°C) evaporates the moisture while lignite is broken up by beater mills

much of drying energy escapes as latent heat in vapour

**Figure 7 High moisture lignite firing – conventional drying/milling system** (diagram based on Alstom and RWE sources)

retrofitting, and potentially provide a means of improving existing plants (Babcock Borsig Steinmüller, no date (b)). Flue gas heat recovery can in principle be applied to bituminous coal fired plants, but has been used at only a few such plants. One, using the Powerise© system referred to above, is at Mehrum in Germany (see Adams, 2009), while a somewhat similar Chinese system has been installed at Waigaoqiao No 3 USC plant in Shanghai, China (see Section 5.23.1).

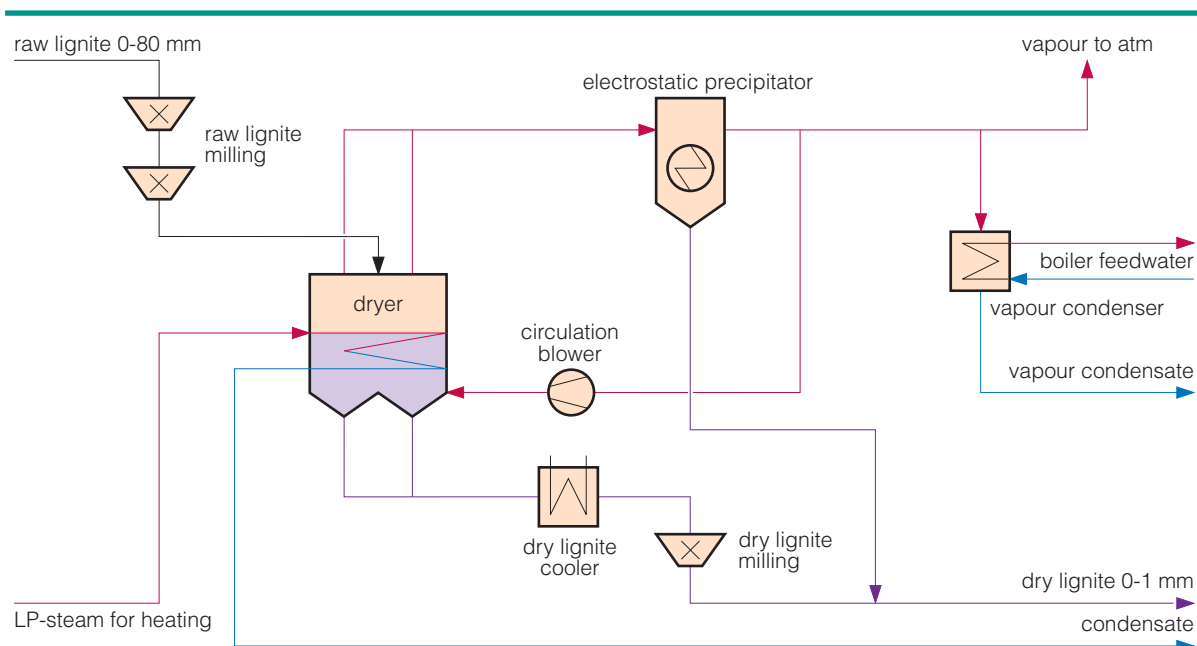
Use of the above systems, together with higher steam conditions and other measures in the modern lignite plants in Germany, enables significantly higher performance than from subcritical designs. However, separate lignite pre-drying using low-grade heat, with as much recovery of this heat as possible, offers the greatest potential efficiency increase for these plants in the immediate future. For a new unit, the gain in HHV or LHV efficiency would be very significant, at about four percentage points, so CO<sub>2</sub> emissions would decrease substantially, by about 10%. New plants are not the focus of this report, but it can be mentioned here that commercial designs for dry lignite-fired utility boilers have been developed. In a recent paper, Alstom have given a detailed description of the differences between their ‘dry’ (12% moisture) lignite boiler design and current designs (Chen and others, 2012). As well as the large efficiency improvement, a new dried feed boiler will offer the benefits of greater turndown, faster load following and avoidance of the need for oil for start-up and support firing. Careful design is always necessary in lignite boilers because of the high slagging tendency of the fuel.

#### 3.1 RWE’s WTA process

For existing boilers, conversion to dry lignite firing is possible, but in this case for part of the fuel flow

generally employed for the higher moisture lignites have beater wheel mills that serve not only to break up the fuel but also to draw 1000°C furnace gas from the boiler to evaporate the moisture and convey the comminuted lignite and water vapour to the burners (see Figure 7). The use of such high grade heat for drying and passing all the evaporated moisture through the boiler restricts generation efficiencies and leads to higher CO<sub>2</sub> emissions than from plants firing lower moisture coals at similar steam conditions.

Some modern USC lignite plants in Germany extract more of the remaining sensible heat and a small proportion of the latent heat in the flue gases using flue gas coolers that can take the temperature down as low as 100°C (Babcock Borsig Steinmüller, no date (a); IEA, 2007), so that efficiency gains of 0.5–0.9 percentage points may be obtained. These Powerise© flue gas cooling systems, constructed using steels and polymers that are resistant to acid corrosion, can be supplied for



**Figure 8** RWE's WTA lignite drying process as used in the prototype at Niederaussem (von Bargaen, 2012)



**Figure 9** RWE's commercial prototype WTA dryer at the Niederaussem power plant in Germany (von Bargaen, 2012)

only (up to 30% for PCC boilers; CFBC boilers could take more). Consequently, a one percentage point gain and a CO<sub>2</sub> saving of about 2.5% is likely, depending on the efficiency of the existing boiler. The furthest developed lignite drying system is RWE's WTA steam fluidised bed dryer. Lignite of 50–55% inherent moisture has been successfully dried to 12% moisture and fed continuously from RWE's commercial prototype of the dryer (*see* Figures 8 and 9) to the 1000 MW BoA (high efficiency) USC Unit K at the Niederaussem power plant.



The system installed at Niederaussem uses fine grained lignite (0–2 mm after milling of the raw 0–80 mm coal), and produces a 0–1 mm dried product after final milling. This product size is more suited to PCC applications than the coarser feed version also developed by RWE, and has reduced fluidising steam requirements and better heat transfer, giving equipment size savings (Zhu, 2012). Here, the WTA system is the open cycle variant, which takes LP steam from the power plant for heat input to the fluidised bed heat exchangers. Part of the evaporated steam is recirculated for fluidisation, and the rest is condensed to provide some of the low grade heat for the power plant's boiler feedwater. [Another version of WTA compresses the liberated vapour for condensation in the heating tubes of the steam dryer, thereby recirculating the heat of evaporation back into the drying process, forming what is effectively an open heat pump cycle.] The dryer at Niederaussem is at full commercial scale: commercially supplied WTA dryers would be no larger. It was designed to dry 210 t/h of 50–55% moisture lignite to produce 110 t/h of dried product, which corresponds to 30% of the fuel requirement of the 1000 MW BoA USC unit at MCR. Initial difficulties to achieve dryer performance with a very cohesive and xylite-rich coal have been resolved by process modifications in 2012 and the WTA plant is now operating very stably. The dried lignite has previously been fed to the existing dry lignite start-up burners on the USC unit (Chen and others, 2012). However, this had resulted in slagging issues and the BoA USC unit was modified in 2013 to introduce the dry lignite at a lower position into the combustion chamber (through the eight beater mills). Initial experience with this new arrangement has been positive (von Barga, 2013).

Availability of the WTA plant was 94% during continuous operations in 2011. Product consistency is good, with moisture content at within 0.5 percentage point of 12% moisture. The dryer now achieves 83% of the original design throughput (174 t/h fuel input), limited only by throughput in the raw coal path. RWE is confident to resolve these issues soon (von Barga, 2013). Heat transfer in the Niederaussem WTA unit matches that obtained on the smaller WTA-2 test plant at the lignite beneficiation plant in Frechen. Currently, RWE is expanding its lignite drying capacity at Frechen by refurbishing the original WTA-1 plant, which had been in test operation from 1996-1999 (von Barga, 2013).

The technology is ready, and is being licensed to three suppliers (Linde, Uhde and another, as yet unspecified, company). RWE will provide tests, basic design, and support, while the licensed suppliers will produce detail designs, carry out erection and commissioning, and provide the commercial guarantees for clients.

### 3.2 Vattenfall's PFBD process

Other lignite drying systems include Vattenfall's similar but higher pressure steam fluidised bed drying system (PFBD process), which may give an additional efficiency advantage from the value of the liberated pressurised vapours for further use. However, this is still at the pilot stage only with some potential challenges to surmount.

### 3.3 Great River Energy's DryFining™ process

In the USA, Great River Energy's DryFining™ process for a less intensive drying of lower moisture lignites has been demonstrated at around 100 t/h at their Coal Creek Generating Station in North Dakota (Bullinger and Sarunac, 2010). Here, the power plant uses a pulverising and firing system similar to that of a bituminous-fired system, with primary air fed to pulverisers, rather than using beater mills drawing furnace gas. The dryer reduces the moisture of the lignite from 38.5% to 29.5% in a fluidised bed of warmed air (at around 51°C), heated by cooling water outflow from the condensers. The outlet temperature from the mills was close to that for undried coal, and fewer mills were needed in service because of the lower fuel feed rate. Mill power was reduced by 13–14%. As would be expected, the primary air flow was reduced, although secondary air flow was increased, and

total air flow remained constant. CO<sub>2</sub> emissions were reduced by 4%, and accompanying benefits were major reductions in emissions of SO<sub>2</sub> (52%, from pyrites separation during drying and better collection efficiency), NO<sub>x</sub> (32%, from improved coal fineness and air and fuel distribution to furnace) and mercury (40%, from segregation of ash minerals plus improved collection efficiency). GRE is now offering the technology commercially in conjunction with its development partner, WorleyParsons (Bullinger, 2010).

### 3.4 ECT's Coldry process

Another lignite pre-drying system is the Australian Coldry Process, owned by Environmental Clean Technologies Limited (ECT), that produces a pelletised product (ECT, no date). ECT say that these could be fed to unmodified lignite plants after simply mixing with raw fuel at up to 30%. The Coldry system would use warm air from the power plant for conditioning and final drying of the product. These and other lignite drying processes are described by Zhu (2012).

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## 4 Major plant modifications

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Major plant modifications, such as conversion of subcritical to supercritical or ultra-supercritical (USC), will raise the thermal efficiency more substantially. Although more expensive than boiler refurbishment or turbine retrofits, major modifications offer a lower cost than plant closure followed by a new build.

### 4.1 Conversion of subcritical to USC

Studies have been carried out at power stations in the UK with a view to re-boiling and partial turbine replacement to convert 16.5 MPa/540°C/540°C 500 MW subcritical units to USC systems. An opted-out 500 MW unit at Ferrybridge in the UK was one of these potential projects (Upton and others, 2007). A one-year FEED study was completed in 2007 for a (nominal) 29 MPa/600°C/610°C retrofit. Savings of capital requirements and construction time were expected compared with a completely new-build plant. Net generation efficiency was projected to increase from 38% to over 44% (LHV basis), saving around 500,000 t/y of CO<sub>2</sub> emissions. The proposed design employed the Doosan Babcock low mass flux vertical furnace tube technology (POSIFLOW™) to reduce boiler feed pump power consumption, and provide simpler boiler erection. However, the plant owner (Scottish and Southern Energy (SSE)) decided not to proceed with the project, citing rising equipment costs as factors in the decision.

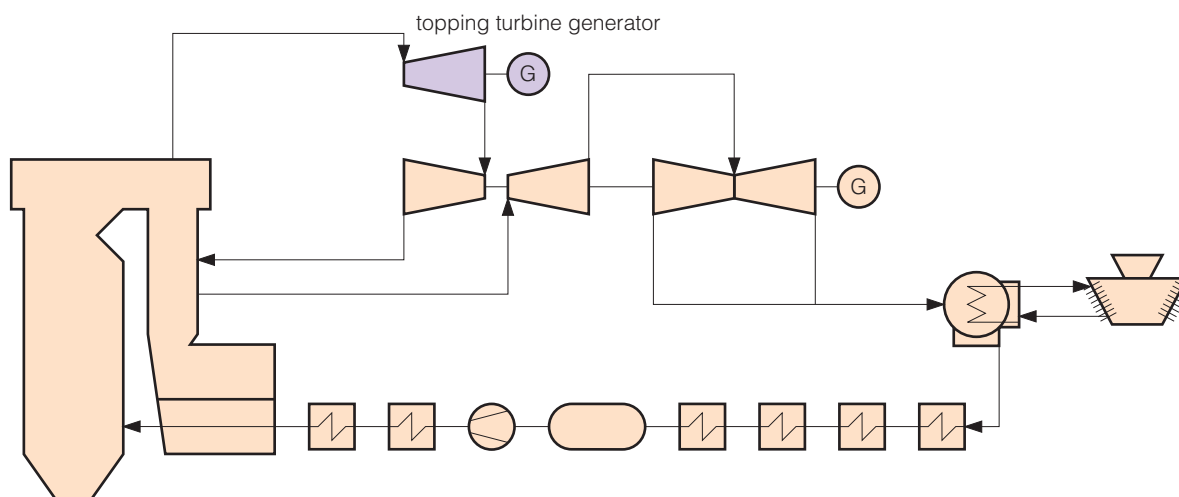
A similar USC retrofit study based on Ratcliffe-on-Soar power station (4 x 500 MW) as an example of the UK's 500 MW fleet was also conducted in the UK in 2007. In this case, CO<sub>2</sub> capture was also envisaged. A 44–45%, LHV, net, efficiency in absence of the CO<sub>2</sub> capture was predicted for conversion to a 29 MPa/600°C/620°C system (Panesar and others, 2009). Again, although the USC retrofit was concluded to be technically feasible, while making substantial use of existing components, no project has emerged.

Parsons-Brinckerhoff have published a study of options for continued operation of plants that have been opted out, and so are due to close in the near future, under the EU LCPD/IED regulations. For conversion of a reference subcritical lignite 4 x 500 MW plant to a 2 x 1000 MW supercritical system (presumably USC), the efficiency was calculated to change from 38% to 41%, LHV, net (Lloyd and Craigie, 2011).

### 4.2 Conversion to A-USC

An extreme example of modification could be a future change of a PCC plant to advanced USC (A-USC) steam conditions using steam pressures and temperatures approaching 35 MPa/700°C. The necessary materials and fabrication and repair techniques for a commercial A-USC plant to be viable are still the subject of R,D&D in the EU, USA, Japan, China, India and Russia (*see, for example*, Phillips, 2012; IEA, 2012). However, it has been suggested by EPRI that it may be possible to demonstrate aspects of the technology very soon by fitting an existing subcritical PCC plant with a topping turbine, exhausting to the inlet of the existing HP turbine. Steam at up to 680°C would be supplied to the topping turbine generator. [Figure 10](#) shows an example cycle to illustrate the principle.

Performance estimates by EPRI indicate a potential 3–3.5 percentage point raising of efficiency, depending on the host plant class (*see* Table 3). However, as of April 2012, there had been no 'takers' for this proposal (Phillips, 2012). Materials developments needed for A-USC technology will form the topic of a future IEA Clean Coal Centre report.



**Figure 10 Suggested demonstration of A-USC using a VHP turbine exhausting to an existing subcritical turbine (Phillips, 2012)**

<b>Table 3 Performance estimates for A-USC demonstrations as a topping cycle on an existing PCC plant (Phillips, 2012)</b>				
Base plant size	120 MW	160 MW	250 MW	500 MW
Base cycle	Non-reheat	Reheat	Reheat	Reheat
Base main steam temperature, °C	538	538	538	538
Base main steam pressure, MPa	12.4	12.4	16.5	16.5
Base thermal efficiency, % (HHV, net)	33.5	35.3	35.9	36.4
A-USC topping steam temperature, °C	682	682	671	671
Efficiency with A-USC, % (HHV, net)	37.1	38.9	38.9	39.2
Note: US Pittsburgh No 8 bituminous coal assumed as fuel				

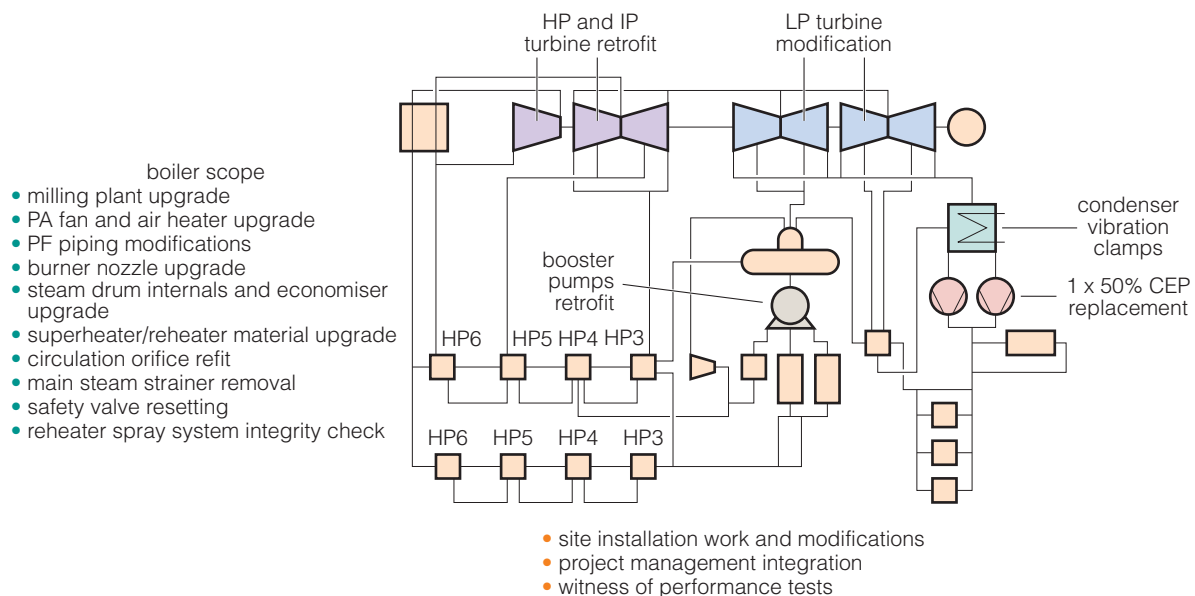
## 5 Case studies

There are many plants where efficiency improvement and upgrading projects have been carried out. This chapter describes some of these and, where available, what the measured efficiency increases or reductions in CO<sub>2</sub> emissions were. It begins with retrofit projects at plants in some non-OECD countries, followed by retrofit projects in the EU and other OECD countries. Less major but also very effective techniques of retrofitting intelligent sootblowing and furnace monitoring follow, while an account of efficiency improvement at a nearly new plant in China illustrates that significant aggregate gains are possible by careful attention to potential minor sources of inefficiencies.

### 5.1 Arnot, Republic of South Africa

Eskom, the nationalised generation company in South Africa has recently embarked on a programme of installing supercritical plants, recommissioning 4 GW of mothballed subcritical units and upgrading of other units to expand capacity. Arnot is a 6 x 350 MWe coal-fired power station, opened in the early 1970s that was the first of these plants to be upgraded in this programme (Davies and others, 2010, 2012). Alstom was awarded a contract in 2006 to upgrade the output of each unit to 400 MWe and a life extension of 20 years. The project covered the boiler, HP, IP and LP turbines, condenser and other balance of plant components. Sumitomo Corporation was awarded a separate contract to supply the station with six new 400 MW hydrogen-cooled Toshiba generators in advance of the retrofit work by Alstom (De, 2003). Alstom was the original supplier of the major equipment, and had the original design documentation for use.

The following account of the retrofit project at Arnot draws on the descriptions given by Davies and others (2010, 2012). An initial review of the main plant areas indicated that the target output of 400 MWe could be achieved with an upgrade or retrofit of the steam turbine and that an increase in boiler load to 108% BMCR was possible. The project scope is summarised in Figure 11.



**Figure 11 Arnot upgrade project — summary scope** (Davies and others, 2012)

#### 5.1.1 Turbines

The major retrofit required on the turbine plant was the complete replacement of the HP and IP

turbine rotors and blading, but the scope also included modifications to the LP turbines and other plant. The HP turbine retrofit consisted of one pre-assembled retrofit module per unit, comprising a drum type single flow HP rotor with reaction blading, together with a new inner casing, with mounted stator blades. New steam seals and gland sealing elements were also provided. The IP turbine retrofit consisted of one partly assembled retrofit module comprising a welded double flow IP rotor with reaction blading and a new inner casing with mounted stator blades. The module was assembled on site and new sealing provided.

The LP turbines required modification to allow for a reduction in the crossover and extraction steam pressures. The swallowing capacity was therefore increased by replacing the first stage stationary and moving blades. The existing condensate extraction pump and the 50% electric and 100% steam boiler feed pumps were also replaced.

### 5.1.2 Boiler plant

The existing furnace size was adequate for the upgrade to 400 MWe for the normally supplied coals. The capacity of the coal mills was increased to 38.5 t/h per mill by fitting larger, high efficiency static classifiers, carrying out a rotating throat modification and upgrading of the gearboxes. New primary air fans were provided. A change of burner nozzles was required to provide the correct relationship between primary and secondary air velocities for the higher output. The new nozzles improved turndown, provided better control of furnace atmosphere and reduced furnace fouling, while being suitable for additional NO<sub>x</sub> reduction measures when needed.

The existing regenerative air heaters on boiler 1 were of the Rothemuhle bisector type with rotating hood and stationary heating matrix, whilst on boilers 2–6 the air heaters were of the Ljungstrom bisector type, with rotating heating surface matrix mounted on a shaft (here, uncommonly, horizontal). Performance was enhanced by Eskom providing new heater elements and Alstom refurbishing the seals. Air in-leakage was reduced to below 9%.

The fifth stage superheater and third stage reheater were upgraded by installing enhanced 9%Cr material on the leading and trailing tubes. To accommodate an increased pressure drop in the superheater, the superheater outlet header pressure was reduced. This necessitated a reduction in the pressure drop between the header and the turbine, achieved by removing a steam strainer and replacing it with a new pipe section. The reheater spray water system, formerly decommissioned, was recommissioned by Eskom after a review by Alstom. To reduce the flue gas exit temperature, two additional rows of economiser surface were added using the existing support structure with only minor modifications.

### 5.1.3 Project implementation and test results

The retrofits were performed during routine major outages of the six units over a three-year period. By 2010, five had been completed (Units 3, 2, 6, 4 and 1) and the remaining Unit (5) was retrofitted in an outage commencing September 2010. The outage period for each was 13 weeks because of the significant amount of work required on the boiler. All work was completed on schedule.

Performance tests carried out by Eskom showed that power output under steady state test conditions was above target, at 406.2 MW for Unit 3 and 409.0 MW for Unit 2. Although more fuel is required to achieve the average 55 MW increase in output, heat balance calculations showed that approximately 15 MW of the additional power was ‘free’ energy arising from increased efficiency. NO<sub>x</sub> emissions were significantly reduced. The station now has the capability of producing an additional 300 MWe of power.

The project at Arnot demonstrated the importance of the initial comprehensive feasibility study in such projects. For example, the latter revealed that substantial work on the boiler was necessary to generate the additional steam required. It also showed the necessity in such projects of all parties participating in an integrated programme to ensure completion of the work on schedule and highlighted the pay-off from applying rigorous quality control procedures. Manufacture of the turbine retrofit inner casings was undertaken in both Europe (Units 3 and 2) and China (Units 6, 4, 1 and 5). However, virtually all manufacture for the boiler upgrades was devolved to South African facilities. Since completion of the project, Eskom's experience with the retrofitted units has been generally positive, and they have provided dependable capacity (Davies and others, 2010, 2012).

Alstom is reported to have received a contract to retrofit the LP turbines on the six 500 MW units at Eskom's Kriel coal-fired power station. The work will involve the supply and installation of 12 inner LP modules and the supply of two spare LP rotors. Installation is scheduled to begin in June 2014. The primary objective is to ensure availability and reliability but there will also be an increase in plant efficiency (Energy Central, 2013).

## 5.2 Suralaya Power Plant Units 1 and 2, Indonesia

PT Indonesia's bituminous coal fired Suralaya power plant consists of eight subcritical units, opened between 1983 and 2011. The boilers of the first two units, rated at 400 MW each and opened in 1983 and 1984, were the subject of a recent upgrade project by Babcock and Wilcox Power Generation Group (B&W PG) to restore their efficiency, increase maximum steam flow and extend their life, while reducing NO<sub>x</sub> emissions and ensuring the units operated with coals of variable characteristics that differed from the original design coal (Borsani, 2012). Steam parameters are 16.7 MPa/541°C/541°C at the boiler headers. The rehabilitation involved the redesign of the convection pass sections and of the combustion systems for NO<sub>x</sub> emissions reduction, upgrades to the pulverisers, and refurbishment of the air heaters.

Pulveriser modifications were needed to meet increased demand from the capacity upgrade and to optimise performance for the wide range of proposed coals. These included:

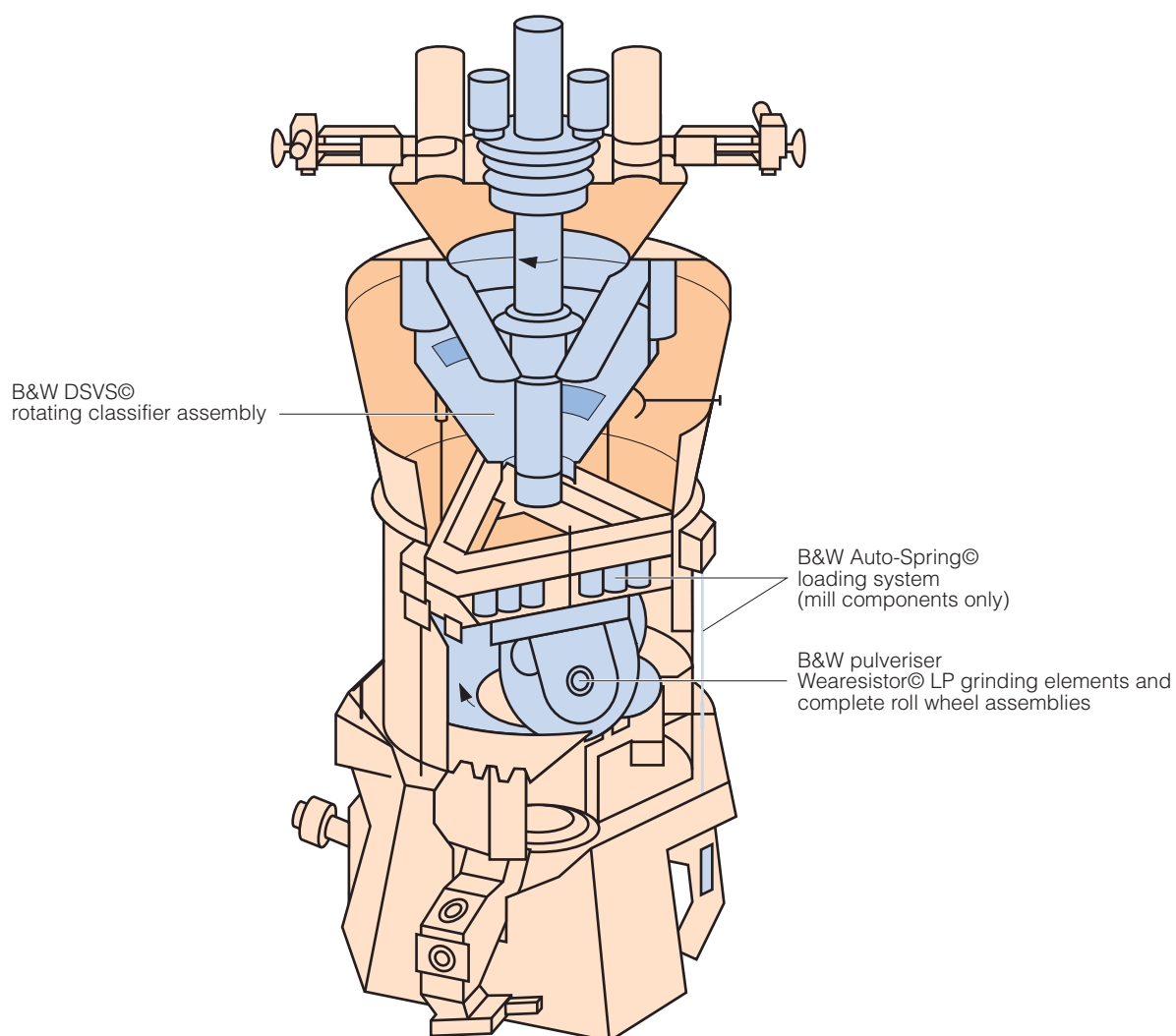
- low profile grinding elements to reduce operating power and allow higher coal flows, while maintaining the original motors;
- a variable roll wheel pressure to accommodate the range of coals;
- rotating classifiers to improve product fineness and maintain combustion efficiency with the new low-NO<sub>x</sub> combustion system.

Other pulveriser components were also renewed to improve availability and to ensure compatibility. [Figure 12](#) illustrates the modifications that were made (Borsani, 2012).

Due to the increase in burner heat input required and to meet optimum combustion efficiency and low emissions, the 35 circular register burners on each boiler were replaced with advanced low-NO<sub>x</sub> burners, designed to fit the original burner openings. To increase output and restore boiler efficiency, all four air heaters on each boiler (two primary and two secondary) were renovated: the radial, bypass and axial seals were replaced and new heating surfaces were installed.

To meet the ASME codes, and current B&W standards, materials were upgraded in most of the boiler pressure parts. The reheater outlet sections were replaced to give a life extension.

Convection heating surfaces replaced were the primary superheater II (PSH II) inlet sections, PSH II outlet and reheater (RH) intermediate sections, secondary superheater (SSH) & RH outlet sections, SSH intermediate sections, and the bifurcate and vertical support tube assemblies. Safety relief valves were replaced in many locations.



**Figure 12 Pulveriser upgrade modifications by Babcock & Wilcox Power Generation Group at Suralaya Units 1 and 2, Indonesia (Borsani, 2012)**

<b>Table 4 Improvements achieved in boiler upgrades at Suralaya power plant, Indonesia (Borsani, 2012)</b>				
Parameter	Pre-retrofit	Post-retrofit	Difference	Change, % of original value
Boiler efficiency, % HHV	85.51	86.22	0.71	0.83
Fuel consumption, t/y *	2,710,000	2,688,000	-22,000	-0.81
Total primary, secondary and ID fan power, kW	30,000	29,000	-1000	-3.33
NO <sub>x</sub> emissions, t/y *	15,970	7,080	-8890	-56
CO <sub>2</sub> emissions, t/y *	5,413,000	5,362,000	-51,000	-0.94
* These data are for both units together, based on a boiler capacity factor of 0.85 and the post-retrofit (increased) boiler output for both the pre-retrofit and post-retrofit values				

All the initial overall objectives were achieved (*see* Table 4). Performance test results are compared on an equivalent basis. The benefit from the airheater was particularly noteworthy. The reduced leakage and lower exit gas temperature provided fan power savings of 1000 kW at MCR for both units and a 0.7 percentage point improvement in boiler efficiency, giving a 0.8% reduction in fuel consumption.



The combined effect of all of the modifications was a reduction in CO<sub>2</sub> emissions of 51,000 t/y and of NO<sub>x</sub> emissions of 8890 t/y for both units together (Borsani, 2012).

### 5.3 AECO Sabarmati D station, India – uprating from 110 MW to 120 MW

NASL, which is a joint venture of NTPC (National Thermal Power Corporation) Ltd, India, and Alstom Power Systems GmbH, provides services for renovation and modernisation of power plants in India and other SAARC (South Asian Association for Regional Cooperation) countries. The company has carried out or is engaged on a number of projects in India, including 30 boiler RLAs (residual life assessments) and 30 turbine RLAs. This project was completed by the company a few years ago. Another completed project is at Bathinda (Section 5.4), and others are in progress (NASL, 2013).

Sabamarti has four lignite-fired units. Unit D is the oldest one, opened in 1978. The scope of the retrofit works, carried out in 2003, included:

- turbine retrofit comprising new HP/IP/LP rotors;
- redesign of reheater to match retrofitted turbine;
- installation of distributed control system and field instruments;
- burner management system.

The results of the work have been as follows:

- machine successfully operated at 120 MW, with better than guaranteed heat rate and output;
- retrofitted machine has operated over the last five years at rated capacity;
- unit has recorded continuous operation of 185 days;
- average PLF ~95% after retrofit.

### 5.4 Renovation and modernisation of 2 x 110 MW units and upgrading of Units 3 and 4 at Guru Nanak Dev TP, PSEB Bathinda, India

The objective of this project, executed by NASL, was to restore the 110 MW rated output of the units 1 and 2 and upgrade Units 3 and 4 to 120 MW. The station, owned by Punjab State Power Corporation Ltd (PSPCL), which takes its coal from Jharkhand, 1500 km away, was commissioned during the 1970s. The R&M works on the first two units were completed in 2006 and 2007. The R&M is providing improved availability, reliability and emissions, through boiler improvements, turbine retrofits and other works:

- addition of a third pass to the air heater;
- upgrading of the mills;
- installation of additional passes to the ESP;
- mono-block HP rotor with high efficiency reaction blading;
- LP turbine retrofitted with new profile blades and diaphragms in all four stages;
- nozzle block for IP turbine;
- new valves;
- replacement HP feedwater heaters of higher efficiency;
- distributed control system;
- pneumatic operation of all actuators with new instrument air compressor system.

After the works on Unit 1, the PLF reached over 98% during some months in 2006 and the first two units are now running at near full capacity. The upgrading of Unit 3 was completed in 2012 and Unit 4 is currently undergoing upgrading. Costs for the R&M have been published, at Rs229 Crore (US\$42 million) for Units 1 and 2 and Rs465 Crore (US\$85 million) for Units 3 and 4 (PSPCL, 2012).

## 5.5 Belchatów, Poland

This is a 12 x 370 MW lignite-fired subcritical plant, dating from the 1970s and 1980s. The owner, PGE, is modernising the boilers and turbines and other systems on the plant to increase its output and efficiency, meet EU emissions regulations and extend its life. Contracts have been placed with Alstom and Babcock Borsig Steinmüller GmbH (BBS). The units already have FGD installed and the low pressure turbines have already been modernised (Power Engineering International, 2011). It is reported that the overall retrofitting programme will save about 1 Mt/y of CO<sub>2</sub> emissions. The work on Units 7–12, consisting of retrofitting the HP and IP turbines, auxiliaries and other related items, at a cost of €140 million, will increase output by 120 MW and save 600,000 t/y of CO<sub>2</sub> emissions by increasing efficiency by 2.4% (basis not stated) (Alstom, 2010). The whole 4460 MW plant currently emits around 30 Mt/y of CO<sub>2</sub>.

The retrofit works were reported in 2012 to have increased the efficiencies of the units by 1.3–2 percentage points. Storm and others (2012) have described the scope carried out by BBS as including (among other areas):

- installation of a low-NO<sub>x</sub> firing system using new burners and installation of overfire air at two levels;
- exchange of superheater bundles to increase the lifetime and steam temperatures;
- renewal of the attemperators;
- installation of an additional feedwater pre-heater on Unit 5;
- new mill classifiers;
- new sootblowers and water lances;
- renewal of cold and hot air ducts;
- overhaul of the FD and ID fans.

The steam parameters of the units are being increased as the primary measure to increase the plant efficiency. This is involving replacement of HP and IP steam lines and boiler heat transfer surfaces augmentation as well as retrofits to the and HP and IP turbines and an increase in final feedwater temperature. Table 5 shows the original and resultant conditions and performances for the units. The works on Units 8–12 are due to be carried out between 2013 and 2016 (Storm and others, 2012).

	Original design	Post retrofit			
		Unit 3	Unit 4	Unit 5	Units 7–12
Year of contract		2005	2007	2009	2011
Main steam flow, t/h	1090	1100	1100	1125	1125
HP steam temperature, °C	540	550	550	570	560
RH steam temperature, °C	540	570	570	570	570
Boiler feedwater temperature, °C	255	255	255	275	255
HP steam pressure, MPa	17.7	18.0	18.0	18.5	18.7
Gross efficiency, % LHV	38.1	39.3	39.3	40.1	39.4
Fuel LHV, MJ/kg	7.75	7.75	7.75	7.75	7.75
Fuel flow, t/h	442	449	449	431	450
Fuel flow, MW LHV	946	960	960	948	965
Gross generation, MW	360	380	380	380	380

The original design was able to accommodate higher steam pressures, but changes to heat transfer surfaces were needed to achieve the higher temperatures. Reheater and superheater areas were increased. The economiser area was also increased to achieve a satisfactory flue gas outlet temperature.

## 5.6 Farge, Germany

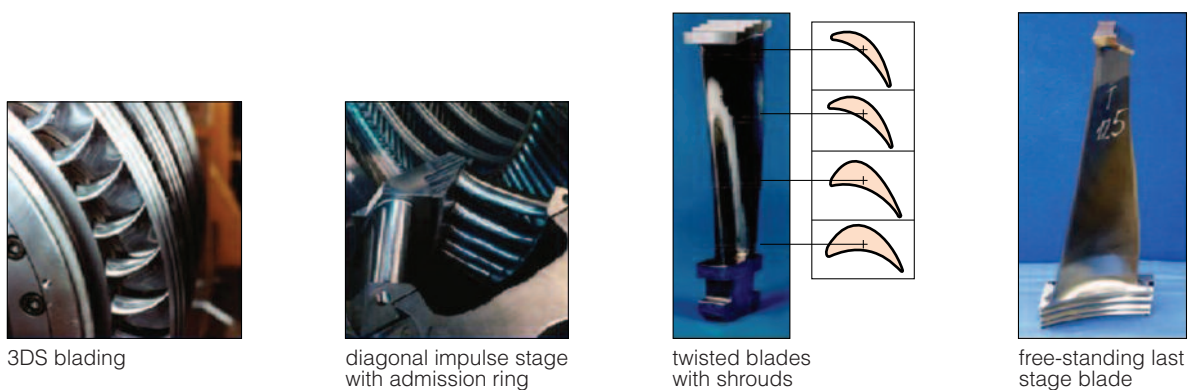
Farge is a 350 MW (gross) bituminous coal fired supercritical (steam parameters: 24.5 MPa/545°C/545°C) unit in Germany owned by E.ON that was the subject of a turbine and condenser modernisation programme by Siemens in 2004. Siemens was the original supplier of the turbine for the plant, which had been operating since 1967. By the time the decision was taken to modernise, the unit had accumulated 200,000 operating hours with 4400 start-ups (Bednorz and Henken-Mellies, 2006; Bielinski, 2012).

The modernisation of the turbines comprised replacement of the rotors, including new 3D blades for the earlier stages of the HP and IP turbines, and installation of new inner casings and stator blades. Leakage losses are relatively high at the admission section to HP and IP turbines, but a better sealed design, using a one-piece admission segment, was used for efficiency gains at these locations.

The three-dimensional geometry of the 3D blades reduced losses at the blade root and tip of the HP and IP turbines. However, in the last stages of the HP and IP turbines and the first stages of the LP turbine, the blades were relatively long and twisted, with integral shrouds, so 3D designs were not required. In the last stage, the rotating blades had no shrouding and the stators in the last row were hollow, enabling suction slots for drawing off surface moisture or introduction of steam for blade heating. Figure 13 shows some of the introduced turbine improvements.

For the new condenser, a tailor-made tube bundle arrangement was designed. There were four fewer tubes in the condenser, yet a 3.7 MW improvement resulted with the new design. The new bundles and the base plates onto which they were welded were constructed from stainless steel. The condenser pressure was 2.3 kPa compared with 3.8 kPa for the original system (Bielinski, 2012). The condenser design featured:

- reduction of steam pressure losses due to a lower steam velocity and optimised tube arrangement;
- optimisation of air removal;
- provision of a horizontal bundle at the bottom for deaeration by upward flow of steam.



**Figure 13** Turbine improvements at Farge Power Plant, Germany (Bednorz and Henken-Mellies, 2006)

**Table 6 Contributions to increased performance at Farge Power Plant, Germany (Bielinski, 2012)**

Area of improvement	Increase in gross power produced, MW
New IP/LP rotor and inner casing	14
New condenser modules	3.7
Maintenance of HP turbine	2.0
Flow optimisation at deSOx	1.0
Flow optimisation at superheater	0.4
Sootblower optimisation	0.1
Other combined improvements	0.8

Performance tests showed that a power increase of 22 MW was obtained. Table 6 shows the contributions to the increase in performance. The efficiency increased from 39.4% to 42.3%, believed to be on a net power, LHV basis.

The above shows that it is not just subcritical coal-fired power plants that can be worth modernising. Here is an example of a mature supercritical plant that has had works done that have provided a major boost in performance, reduced coal consumption by up to 40,000 t/y, and extended the station's life by more than 15 years. The work was carried out during a six-week planned outage.

## 5.7 Ibbenbüren, Germany

Ibbenbüren is a 750 MW hard coal fired (including anthracite) subcritical unit in Germany, owned by RWE, that was the subject of a turbine upgrade in 2009. Steam conditions are 20 MPa/530°C/530°C. In 2009, the high-pressure, intermediate-pressure, and two low-pressure turbines as well as the two condensers – all commissioned in 1985 – were modernised in a ten-week period by Siemens. Output was increased by 86 MW, half of which was from increased efficiency, from installing new turbine rotors and inner casings with advanced blading and seal technologies, combined with the installation of optimised condenser tube bundle modules. The efficiency increase gave a saving of up to 260,000 t/y of CO<sub>2</sub> emissions. The system also had better operating characteristics and greater flexibility. A life extension to 2030 was achieved (Walsh and Sommer, 2012; Bielinski, 2012).

## 5.8 Heilbron Unit 7, Germany

Heilbron Unit 7 is a 750 MWe (nominal) plus 300 MWth combined heat and power subcritical plant, fired on bituminous coal, opened in 1985 and owned by EnBW. Following a FEED study by Alstom, the company was contracted to carry out a turbine retrofit programme and boiler and fuel preparation systems upgrade to enable output and efficiency to be increased and to enable a coal specification change as well as cofiring of sewage sludge. In the fuel preparation area, the four pulverising mills were replaced, an additional primary air fan added, and additional steam pre-heating of the combustion air added to prevent corrosion in the existing air pre-heater. The turbines were retrofitted throughout with modern blading of higher efficiency, while retaining the outer casings. Inner casings, shafts and seals were replaced. Power was increased considerably, (from 766.3 MW to 827.2 MW), and efficiency increased by 1.1 percentage points. Specific emissions of CO<sub>2</sub> were reduced by 2.8% (Stamatelopoulos and others, 2011).

## 5.9 Karlsruhe Unit 7, Germany

This is a 535 MWe/220 MWth bituminous coal fired subcritical unit owned by EnBW and opened in 1985. It was the subject of a retrofit in 2010 of the LP turbine by Alstom with modern blading. The other two turbine sections had already been upgraded in 2005. Electrical output was measured before and after, and increased by more than expected (27 MW) because the LP turbine had deteriorated considerably before the project was implemented. The efficiency increase was 1 percentage point, with a decrease in specific CO<sub>2</sub> emissions of 2.5%. Changes were also made to the firing system to

cope with changed coal characteristics and to reduce the ammonia quantities needed for the SCR system. These consisted of modifications to the mills, burners and boiler air supply entry points. The modifications allowed the excess air to be reduced from 25% to 20%, reducing fan power consumption, while reducing primary NO<sub>x</sub> generation. All work was accomplished within a planned overhaul window (Stamatelopoulos and others, 2011).

## 5.10 Altbach Unit 2, Germany

This is a 430 MW bituminous coal fired plant owned by EnBW opened in 1997. It is linked on the water-steam side to a small natural gas-fired combined cycle unit. A routine inspection revealed that the IP turbine had suffered damage so the decision was made to retrofit this part of the plant. Siemens was awarded the contract, and the project was scheduled for March 2012 and consists of the now familiar replacement of the shaft, blades and inner casing. Advances in blade profiles and sealing since the turbine was designed will give an increase of 2 MW output for the same firing rate. There is also a good margin for increasing capacity by 21 MW through burner and mill modifications that will also be carried out by Steinmuller Engineering (Stamatelopoulos and others, 2011).

## 5.11 Jänschwalde Power Plant, Germany

The Jänschwalde power station is a 6 x 300 MW subcritical lignite-fired plant, owned by Vattenfall, and opened during the 1980s. It has had various improvements over the years, including improved combustion systems for lower NO<sub>x</sub> production, upgraded ESPs and addition of FGD. Turbine retrofits have also been carried out by Alstom to achieve increased output and an efficiency increase (Baumgaertnar and Rediess, 2011). LP retrofits were carried out in the 1990s and the HP turbines were replaced 2003 and 2006 because the fuel saving benefits were seen to make the work particularly cost-effective. Replacement of the rotors, blades, sealing and inner casings of the IP turbines is currently in progress.

Baumgaertnar and Rediess (2011) describe the work on the IP turbine of Unit D, which involved a change from impulse to reaction blading with an increased number of stages. The outer casing also needed some minor reworking to restore correct geometry. All steam parameters were maintained. Factors contributing to the improvement in efficiency included 3D blading, optimum stage loading, and efficient labyrinth type sealing. The result was that the IP turbine was 3.3% more efficient than before, producing an additional 6.3 MW without any additional fuel. Thus, for the same output, 46,000 t/y of CO<sub>2</sub> emissions are saved. By the time all the work is complete on all the blocks, the modernisations over the life of the plant will have increased output from 3000 MW to 3210 MW and raised efficiency to 36% LHV, net.

## 5.12 J H Campbell Power Plant, USA; boiler upgrade and fuel switch from bituminous coal to subbituminous coal

J H Campbell Unit 3, owned by Consumers Energy, dates from the early 1980s and is an 820 MW plant. Steam conditions are 17.5 MPa/541°C/541°C. The wall-fired boiler was designed to burn a range of Eastern USA bituminous coals but was modified in the late 1990s to use a blend of Powder River Basin (PRB) subbituminous coal (70% heat input) and Eastern coal (O'Brien and others, 2012). Table 7 summarises the phases of the upgrade project, commencing with first conversion to partial PRB firing, up to the most recent change to 100% PRB.

In 1999, Doosan Power Systems supplied a low-NO<sub>x</sub> combustion system (low NO<sub>x</sub> burners and an overfire air system) to give emissions of 370 mg/m<sup>3</sup> at 6% O<sub>2</sub> for the PRB/Eastern coal blend. The owner subsequently required the NO<sub>x</sub> emissions to be further reduced while firing 100% PRB for the

<b>Table 7 J H Campbell Unit 3: boiler upgrade project phases and achievements since 1997</b> (O'Brien and others, 2012)	
Phase	Achievement
Phase 1	Achieved greater than 50% reduction in NOx with partial firing of PRB
Phase 2	Confidence in results of engineering study with respect to assessment of the coal fired units to determine the most cost-effective method for reducing NOx emissions
Phase 2a	Achieved a higher proportion of PRB coal fired Plant modifications allowed rated MWe output to be maintained
Phase 2b	Allowed 100% firing with PRB coal Further reduction of NOx emissions Solved an existing erosion problem in the convection pass

same boiler output. Changing to 100% PRB coal firing has various implications for plant design because of its higher moisture content, lower calorific value and severe slagging and fouling tendencies. Furnace deposits also tend to be reflective, reducing furnace performance, reducing the evaporation rate and increasing the furnace gas exit temperature (FGET) (O'Brien and others, 2012).

Radiant secondary superheaters were already installed to maintain the FGET below the ash fusion temperature, but these were not adequate to cope with the introduction of PRB coal and there were issues with slag build-up. In Phase 2b, they were therefore replaced with a platen type superheater, designed to meet the increased thermal duty (O'Brien and others, 2012). The increase in the secondary superheater surface results in a corresponding reduction in heat absorption by the (convective) primary superheater. The reduction in furnace absorption also means that the economisers have to be increased in size to accommodate some of the deficit in the evaporative heat absorption.

The project phases since 1997 and their achievements are summarised in Table 7.

The Phase 2b works carried out since 2006 to achieve firing on 100% PRB coal involved major heat transfer surface replacements and upgrades to reduce gas velocities in the rear gas pass while keeping steam production at the original design conditions. Doosan Power Systems was responsible for project management and the supply and commissioning of the equipment and the client was responsible for erection. The project involved close integration with the customer and other contractors. The project value was US\$400 million including subsequent installation of SCR technology by other suppliers to deliver NOx emission reductions of 70% (O'Brien and others, 2012).

The scope of supply for Phase 2 of the project included:

- additional capacity overfire air ducting and additional overfire ports;
- replacement of secondary superheater division walls with platen secondary superheaters, to reduce FGET;
- new furnace roof tubes and tube penetrations to accommodate the platen superheaters;
- new superheater and economiser surfaces, and new side wall panels and headers;
- new rear convection pass pressure parts except for final superheater;
- replacement reheater and economiser surfaces;
- rear pass enlarged to reduce erosion;
- eight new mills, with dynamic classifiers;
- new primary air heaters of higher duty;
- new primary air fans of higher duty;
- sootblower upgrades and sootblowers on furnace walls replaced with water cannons.

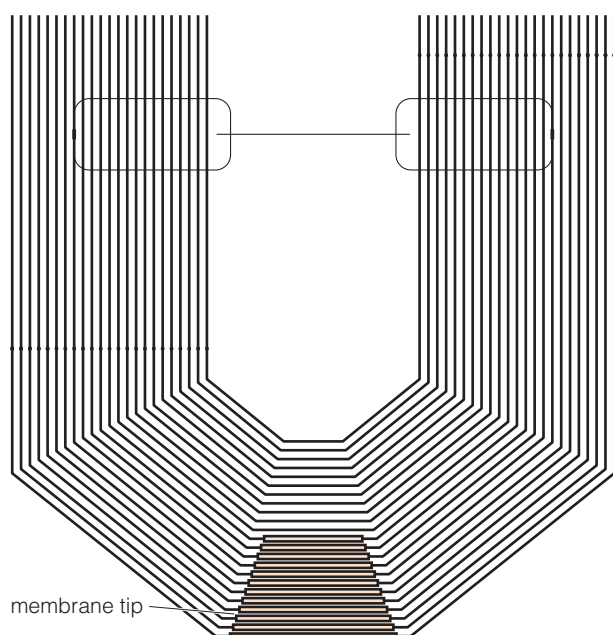
Stage 2b successfully resulted in 100% PRB firing, further reduction of the inlet NOx emissions to the

<b>Table 8 J H Campbell Power Plant, USA: test results from boiler upgrade and fuel switch</b> (O'Brien and others, 2012)			
Phase 1	Before upgrade	Design requirement	Achieved result
Main fuel	100% Eastern bituminous coal	30% PRB/70% Eastern coal	30% PRB/70% Eastern coal
NOx production	305 g/nGJ	137 g/nGJ	127 g/nGJ
Fly ash carbon	6–7%	7–11%	6–7%
<b>Phase 2a and 2b</b>			
Main fuel		100% PRB	100% PRB
NOx production		123 g/nGJ	114 g/nGJ
Output, MW		820	820
SH outlet pressure	17.5 MPa	17.5 MPa	17.5 MPa
SH outlet temperature	541°C	541°C	541°C
RH outlet temperature	Original design value not achieved	541°C	541°C

SCR system and resolution of the existing erosion issues in the boiler's rear flue gas pass. Table 8 shows the test results from all of the project phases.

### 5.13 Comanche Station Unit 1, USA – availability improvement

PRB coal is also fired at Comanche Unit 1, which is a 19.5 MPa/541°C/541°C, 350 MWe plant, owned by Xcel Energy and dating from 1972. The tangential-fired boiler had for a long time given serious slag accumulations on the pendant division panels and platen heat exchangers, affecting availability and output. The division panels are lower sections of the superheaters below the platen superheater surfaces. Detaching of heavy accumulations had from time to time caused deformation and damage to lower sections of the boiler. Mornis and others (2011) describe the work to solve these problems by Doosan Power Systems through installation of new division panels incorporating membrane tips.



**Figure 14 Membrane tip platen, Doosan Power Systems** (Mornis and others, 2011)

The membrane tip design has also been applied to platens on other plants with equal success. The lowest, horizontal tubing lengths are minimised, by tapering the shape of the division panel or platen, and these horizontal tubes are fitted with a membrane across them (see Figure 14, here shown for a platen superheater). The former minimises the amount of surface that is most prone to slag accumulation, while the latter prevents slag from encircling the individual tubes, so preventing it from attaching so strongly. The slag that does accumulate on the membrane

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surfaces is thereby considerably easier to remove by sootblowing. Tube alignment in that vulnerable area is also maintained as the membrane holds the tubes fixed in position. Misalignment in the past had made slag removal by sootblowing more difficult. The new components were installed during an outage period of eight weeks. It was reported that, in the period from recommissioning in May 2011 up to December 2011, deposits on the lower superheater sections were almost non-existent (Mornis and others, 2011).

## 5.14 J P Madgett Station, Alma, WI, USA

Madgett is a 365 MW subcritical unit, opened in 1979, that had a turbine retrofit in 2004 by Siemens during a 50-day outage (Peltier, 2006). The owner, Dairyland Power Cooperative, had the HP/IP turbine unit retrofitted with new rotors with new blading, inner casings and stator blades. The work was carried out at the same time as major boiler maintenance and while replacing the control system with a modern distributed control system. The new shrouded blading of the replacement HP/IP module enabled improved sealing to be incorporated. The retrofitted LP turbine internals included reaction front-end blades with integral shrouding, free-standing 95.8 cm last stage blades and a single inner casing. Both new turbine systems had solid rotors to provide longer life.

Over the load range, the efficiency of the HP turbine increased by 8–10%, while that of the IP turbine increased by 2–4%. The LP turbine improvements gave a 7–8 MW increase in output. Overall output rose by 20–27 MW.

## 5.15 Labadie Station, USA

Labadie is a 4 x 600 MW subcritical station owned by AmerenUe and opened during the 1970s. It has operated on PRB coal following boiler modifications since the 1990s. More recently, the turbines have been retrofitted by Alstom. The HP/IP combined units only were retrofitted on Units 1 and 2. Improvements included better steam sealing with cold reheat steam rather than main steam and a HP/IP turbine of impulse type with full arc admission with an opposed double flow design that avoided the axial thrust of the old configuration (also reducing the number of positions that needed sealing). The outer casings were also replaced for maintenance reasons. The retrofits resulted in an additional 27 MW output from each unit (Peltier, 2006).

On the other two units, the HP/LP turbines were analogously retrofitted, while the LP turbines were replaced. The original LP turbines had 76.2 cm final stage blades, whereas the new turbines had 86.4 cm blades. The owners found that a whole-plant approach to planning the changes was important to obtaining maximum benefits. For example, the turbine retrofits were designed to allow any boiler changes for greater steam flow to be accommodated and so used effectively.

## 5.16 Northport Station Unit 3, USA

Northport is a 1520 MW station dating from the 1960s and 1970s, owned by KeySpan Corporation. Unit 3 is a 375 MW unit that was suffering a loss of output and efficiency for some time when it was taken out of service in 2004 for an overhaul by TurboCare. Internal steam leakage from HP to IP in the combined HP/IP unit was diagnosed as responsible (*see also* Section 2.1). In this case, leakage was estimated by TurboCare at 11%, and it was predicted to be potentially reducible to 4%. The works involved machining of the turbine inner casing to restore it to flatness specifications along the mating joint, installation of new labyrinth seal packing rings and brush seals and blade tip seals. Retractable packing seals of the type shown in Figure 3, fitted also with brush seals as described in Section 2.2.1, were used between the stages. This prevented rubbing during start-up but reduced clearance to virtually zero during normal operation. The works, together with others, increased output



by 14.1 MW. A 334 kJ/kWh net heat rate gain (out of 491 kJ/kWh total) came from the turbine improvements (Peltier, 2006).

## 5.17 Eraring Power Plant in NSW, Australia: boiler and turbine upgrade

Eraring Energy's bituminous coal fired power plant in New South Wales, Australia, consists of 4 x 660 MW subcritical units (original rating) with design steam conditions 16.7 MPa/540°C/540°C at boiler outlets. It was opened in the early 1980s. By the 2000s, the plant was suffering from failure to achieve rated steam conditions, limited efficiency and flexibility, together with increased operating and maintenance costs. A modelling study by the original equipment manufacturer in 2003 indicated that upgrading the efficiencies of the HP and IP turbines could enable the original 660 MW unit output to be achieved, with potential for further efficiency enhancements to give 720 MW, with peaking capacity of 750 MW (*see* Table 9) using original design steam conditions. Doosan Heavy Industries and Construction was awarded turbogenerator and boiler upgrade contracts and these targets were achieved. The total cost of the upgrade project, carried between 2009 and 2012, was AUS\$613 million. As a result, the project has given a reduction in specific emissions of CO<sub>2</sub> of 30 g/kWh, equivalent to around 450,000 t/y of CO<sub>2</sub> emissions savings (O'Brien and others, 2012).

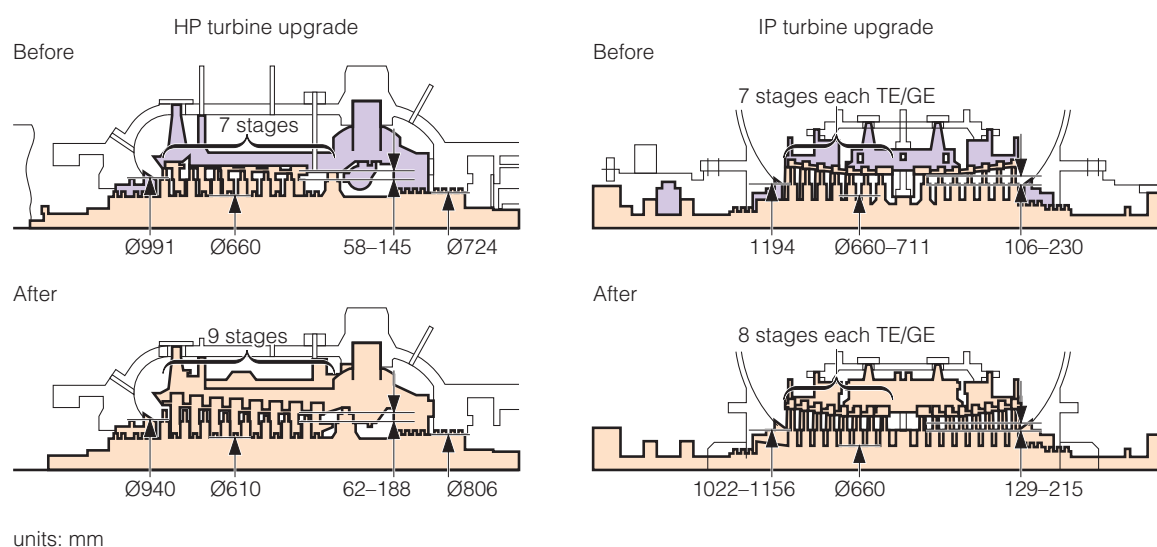
**Table 9 Eraring Power Plant, Australia, turbo-generator upgrade modelling predictions** (O'Brien and others, 2012)

	MCR, %	Output, MWe gross	Steam flow rate, kg/s	Change in flow
Existing turbine	95	660	560	-5%
	100		590	
Turbine upgrade	88	660	537	-9
	96	720	595	+0.5
	100	750	625	+5.6

### 5.17.1 Turbine upgrades

Most of the turbine improvements at Eraring were on the HP/IP system. The existing outer casing was retained, while the inner casing was replaced, as is commonly the case in such projects. However, here it was also necessary to allow a greater steam flow. These considerations meant that new rotors of smaller diameters were needed and the new blades needed to be longer. After several optimisation trials, it was determined that two additional stages in the HP section and one additional stage in the IP section were required (*see* Figure 15).

Because the original bearing span had to be retained, a saving in space was achieved by applying a nozzle plate in the control stage and axial entry dovetails in the IP section. The original turbine had used a (larger) nozzle box design and tangential entry. Advanced blade designs, diaphragm and tip seals and brush seals were also introduced. The generators were additionally re-wound to permit the increased output. The modifications were applied to Eraring Unit 4 in 2009, and successfully demonstrated the predicted efficiency improvements in advance of the integrated retrofit of boiler and turbine on Unit 2 in 2010 (O'Brien and others, 2012).



**Figure 15** Turbine modifications at Eraring Power Plant showing increase in number of stages and changed dimensions (O'Brien and others, 2012)

### 5.17.2 Boiler upgrades

Studies focused on the 3–8°C shortfalls in the final and reheat steam temperatures of the existing natural circulation boiler plant. It was necessary to recover the design steam temperatures and correct an imbalance between evaporation and superheating surfaces. This work included extensive modelling, followed by design, supply and overseeing of the installation of the boiler modifications.

Among the design targets were:

- recovery of 3–5°C shortfall in main steam temperature;
- recovery of 5–20°C shortfall in reheat steam temperature;
- achieve rated steam temperature 540°C at boiler MCR and over the load range;
- achieve 105% of the original boiler design peaking capacity;
- minimise the rear gas pass particle impact erosion wear rates by limiting the maximum flue gas velocities.

The changes in the boiler included:

- additional primary superheater elements;
- additional reheater elements;
- new finned economiser;
- new plain economiser;
- new and relocated headers.

Table 10 summarises performance indicators for Unit 2 before and after the boiler and turbine improvements.

<b>Table 10 Unit 2 boiler upgrade and turbine improvements at Eraring Power Plant, Australia – some performance indicators (O'Brien and others, 2012)</b>					
	March 2009	December 2010	December 2010	October 2010	Target
Gross output, MWe	660	660	720	750	
Main steam temperature, °C	537	540	540	540	540
Reheat steam temperature, °C	530	540	540	540	540
Main steam flow, kg/s	561.4	543.4	600.6	625.0	

Extensive site surveys in particular on the boiler plant proved crucial in identifying and resolving potential construction challenges. Close and regular communication across design, manufacturing and construction teams proved invaluable throughout the project. Single point accountability and defined division of responsibility facilitated project delivery (O'Brien and others, 2012).

## 5.18 Drax, UK

Drax is a 6 x 660 MW (nominal gross), bituminous coal fired power station in the UK, commissioned between 1974 and 1986. Over the last six years, the low pressure and high pressure turbines on all six units have been retrofitted with new internals by Siemens. An average heat rate improvement of 4–5% is predicted from the £100 million (US\$155 million) programme, which has recently been completed (Drax Group, 2007, 2012; Drax Power, 2011). That is equivalent to more than a 1.5 percentage point improvement in efficiency and will save approximately 1 Mt/y of CO<sub>2</sub> emissions. Among the

Year	Work completed
2007	Unit 3 HP module installed
2008	Unit 5 and 1 LP and HP modules installed
2009	Unit 6 LP and HP modules installed
2010	Unit 4 LP and HP modules installed
2011	Unit 2 LP and HP modules installed
2012	Unit 3 LP module installed

TMS (Total Maintenance System) readiness review meetings schedule for all units	
TMS 1	365 days before outage
TMS 2	180 days before outage
TMS 3	60 days before outage
TMS 4	30 days after outage
Monthly update meetings (component manufacturing and site status)	
Joint planning and development	
Combined action items list (joint document reviewed on monthly basis)	
Daily site outage interface meetings	
Weekly site outage meetings to agree progress/issues	
Six-monthly executive steering committee meetings	
Joint HSE meetings, daily joint inspections, weekly audits	

objectives of the retrofit were a 12-year maintenance interval and 300,000 h design life. Output has been increased to 675 MW (gross) per turbine (Austin and Davidson, 2009) and efficiency has recently been reported to have increased to almost 40% LHV, net, (Drax Group, 2012). The overall retrofit schedule is shown in Table 11. During the HP turbine retrofits, the rotors and fixed blading and the inner casings were replaced and the outer casings were retained (Ghent, 2012). Among the issues identified before the retrofit was LP blade erosion. The original LP casings were retained and fitted with new rotors, blading and diaphragms (Power Engineering International, 2012).

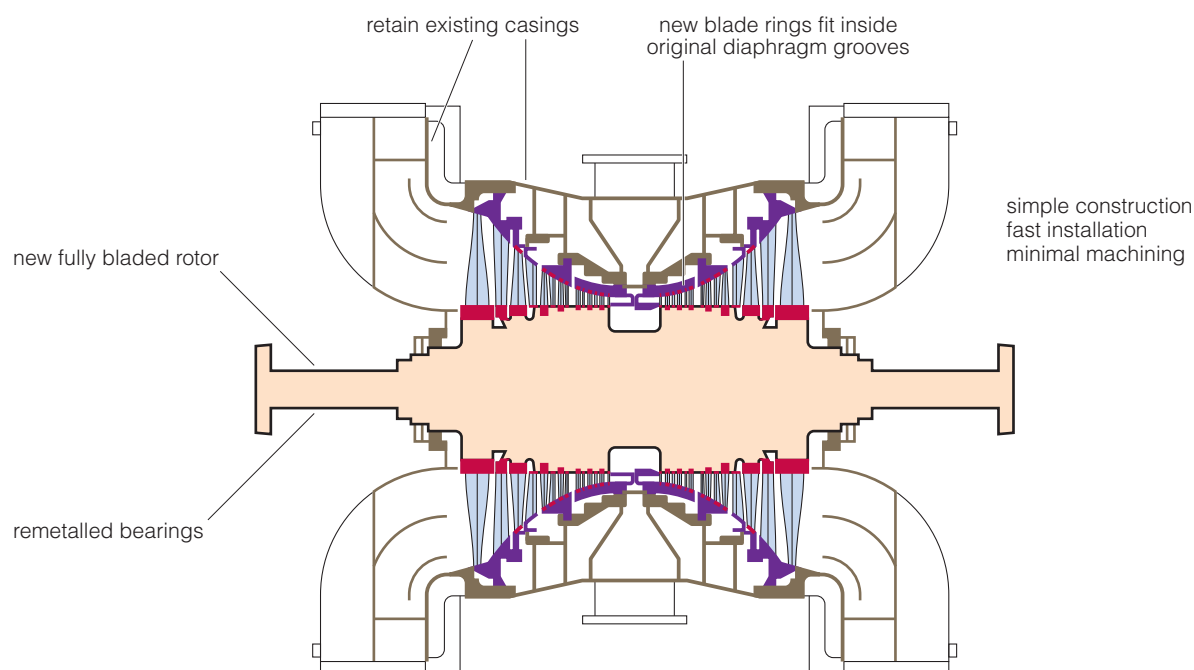
Detailed planning was carried out for each unit with a timetable of readiness review meetings, action lists and regular and frequent site meetings during the works (*see* Table 12).

Among the key co-ordination and technical issues for each unit in implementing the HP and LP upgrade and generator worksopes within 55 day outages were those shown in Table 13.

Published information on the improvements achieved from the first three unit retrofits between 2007 and 2008 is available. The Unit 3 turbine HP retrofit resulted in a 7.07% increase in turbine efficiency. The HP/LP retrofits of Units 1 and 5 achieved heat rate improvements of 2.05% and 2.22%, respectively (Austin and Davidson, 2009).

The retrofit work on the LP Units 1 and 5 are described in detail by Armstrong (2009). The original casings were retained, but the rotors

<b>Table 13 Drax turbines retrofit: some of the key co-ordination and technical issues</b> (Austin and Davidson, 2009)	
LP outer casing	Exhaust machining
HP module	Sub-contractor interface
Generator	Interface between mechanical works by (Drax Power and RWE) with stator inspections (Siemens)
Final alignment	Couplings, bearings (teamwork approach)
Co-ordination	Co-ordination with boiler and condenser works and BOP



**Figure 16 Drax LP turbine retrofit modifications** (Armstrong, 2009)

and original impulse blading were replaced with reaction blading. The inner casings had become distorted, so required machining. The time required for the latter on Unit 1 was reduced from experience on the machining of Unit 5. 19 days were allowed, but only 17 and 15 days were needed for the units. The turbine retrofits gave higher performance from:

- conversion from impulse to reaction blading;
- latest aerofoil blade designs and tip seals;
- optimised flow path from latest design tools;
- free-standing blades (not coupled).

The retrofits also resulted in greater integrity from:

- elimination of 1960s blade root fixings;
- no riveted coverbands;
- no brazed erosion shields;
- improved water extraction;
- improved composition of white metal bearings.

Figure 16 shows the changes made.

As a result of the success of this retrofit, the three intermediate pressure (IP) turbines on the units that are being converted to 100% biomass firing are also to be retrofitted by Siemens (Drax Group, 2013).

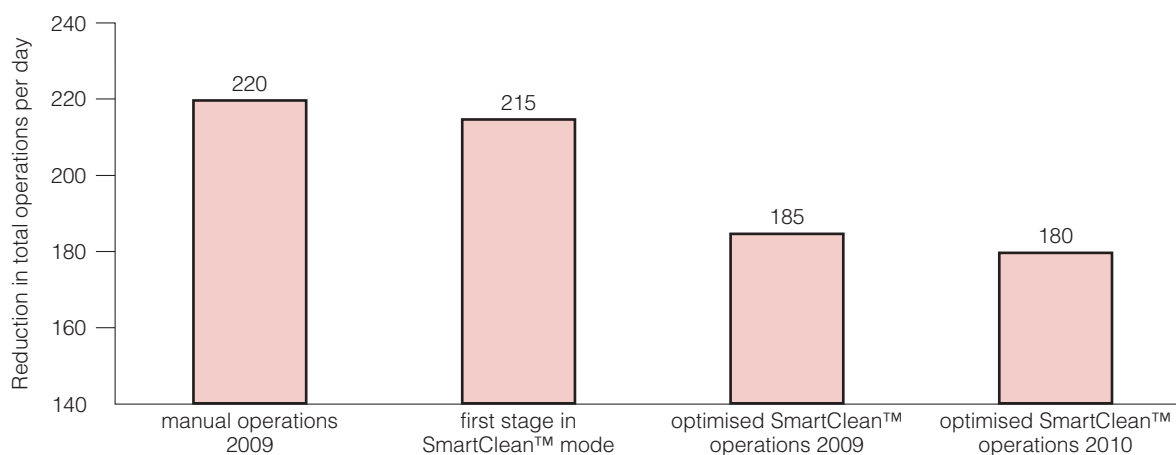
This will help to offset any loss in efficiency experienced as a result of the change in fuel. Each IP turbine will be installed as a module, to ease installation and reduce the duration of the outage required. The first module is scheduled to be installed in 2014, with project completion in 2015.

## 5.19 Jeffrey Energy Center Unit 3, USA – installation of intelligent sootblowing system

Thabot and others (2010) describe the effect of the use of an intelligent sootblowing system at Jeffrey Energy Center Unit 3 in the USA. This is a 780 MW subcritical unit, opened in 1983, firing Powder River Basin (PRB) subbituminous coal. Before it was fitted with the new sootblowing system, this unit had major difficulties. It suffered frequent derates and outages because furnace exit gas temperature was in excess of the ash fusion temperature of the coal, resulting in slagging and fouling, causing tube leaks, plugged pendant heat transfer surfaces and molten ash carryover into the economiser. Previous attempts to solve these problems (adding additional sootblowers, changes to heating surfaces and additional instrumentation) had not prevented the heavy fouling. In contrast, the SmartClean™ System, put in service in February 2009, has been shown to improve boiler efficiency while preventing costly derates and outages. The system continuously monitors the condition of key areas of the boiler and controls sootblower operation accordingly. The three main elements of the system are:

- the Superheater Fouling Monitor (SHFM): this uses strain gauges to measure the amount of ash building up on tube pendants;
- Thermodynamic Model (TDM): this measures the thermodynamic efficiency for each heat exchanger;
- smart sootblowers: these can adjust cleaning intensity and speed during operation.

Two monitoring means are used. The SHFM uses strain gauges, on which the pendants hang, to measure the mass of ash accumulating on pendant heat exchangers. The strain gauges relay the increase in weight to the control system, which then operates the correct sootblower to remove the deposit. The TDM measures the thermodynamic efficiency of each heat exchanger by determining the energy balance around each of the boiler heat exchangers. Any decrease in heat transfer is detected by the TDM, which similarly instructs the system to operate the appropriate sootblower. The system has reduced the number of sootblowing operations (Figure 17) and increased plant efficiency, while eliminating forced outages arising from fouling. The sootblowers are themselves of novel design such



To date - no forced outage due to fouling and no falling clinkers

SmartClean™ priority queue and exclusion logics have improved the plant efficiency and at the same time have reduced the number of sootblowing operations

**Figure 17 Improvement in fouling control at Jeffrey Energy Center Unit 3, USA, through use of SmartClean™ sootblowing system (Thabot and others, 2010)**

that their cleaning intensity can be varied during an operation. The heat rate was decreased (improved) by 0.87% as a result of use of the system (Thabot and others, 2010).

## 5.20 Allen S King Station, Unit 1 – installation of intelligent sootblowing system

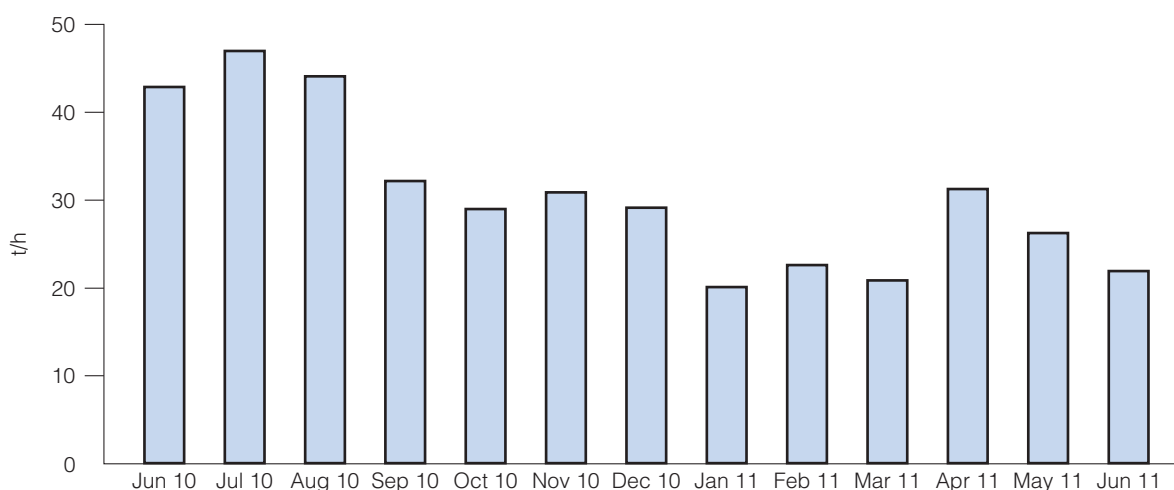
Xcel Energy's Allen S King Unit 1 is a 574 MW plant, opened in 1968, with supercritical steam parameters of 25.2 MPa/541°C/541°C. Here again, the fuel is the highly slagging PRB coal. Babcock & Wilcox Power Generation Group, Inc's (B&W PGG) Powerclean™ intelligent sootblowing system has been applied at the unit's B&W PGG cyclone-fired boiler (Schmidt and Brown, 2011). Previously, in the convection passes, manual operation only of the sootblowers was used, and this had resulted in accelerated erosion, frequent boiler tube failures and reduced performance. Water lancing in the furnace zones was also formerly carried out manually, causing quench cracking on the furnace waterwalls.

The Powerclean system features introduced included:

- an accurate and responsive boiler performance model for system monitoring and feedback;
- elimination of furnace exit gas temperature probes;
- elimination of heat flux sensors in the furnace for control of furnace water cleaning;
- ability to control a variety of cleaning devices including retractable sootblowers, wall blowers, water lances.

The Powerclean system employs the boiler model used originally to design King Unit 1 to enable it to continuously assess whether the furnace is performing as expected. The system uses live data from the distributed control system to calculate heat transfer as well as boiler efficiency and heat rate. This information is then used to determine when and where sootblowing should be initiated to optimise performance. Small groupings of sootblowers were designed to clean different components of the boiler effectively without causing upsets in operating conditions. As part of Powerclean commissioning, a reduction in reheater attemperation spray flows was targeted (*see Figure 18*).

Prior to implementing the Powerclean system, the spray flows averaged around 45,000 kg/h. With the new system, the reheat spray flows have been approximately halved. The efficiency of the unit has also increased. The heat rate was calculated by Powerclean to have decreased from 9223 kJ/kWh to 9061 kJ/kWh (a 1.8% improvement), corresponding to a payback of less than six months (Schmidt and Brown, 2011). These are equivalent to 39.0% and 39.7% (HHV). It was not stated whether this was for gross or net power.



**Figure 18 Allen S King Unit 1 – improvement in monthly average reheat spray flow from using B&W's Powerclean™ system (Schmidt and Brown, 2011)**

## 5.21 Raichur Thermal Power Station, India – smart wall blowing system for improving heat rate

In India, BHEL has developed a smart wall blowing system (SWBS) that is installed at Raichur TPS, Karnataka. Raichur is an 8 x 210–250 MW station, commissioned between 1985 and 2009 (Henderson, 2003; APP, no date). Sootblowing control by the SWBS is based on monitoring of superheater spray flow and furnace heat absorption in different zones. The system helps to maintain the furnace heat absorption at optimum level thereby maintaining the superheater and reheater sprays within limits. The system is described in the best practice manual, produced in India under the USAID (United States Agency for International Development) and APP (Asia Pacific Partnership on Clean Development and Climate) programmes, and referred to in Section 6.5.

The SWBS has waterwall heat flux sensors installed between the wall blowers. The sensors have built in thermocouples and are installed at four elevations with eight heat flux sensors in each wall. The two ends of the sensors are exposed to the flame radiation and the cooling water side. They are connected to a remote control panel linked to the conventional soot blowing system. The heat flux changes, depending upon the thickness and heat transfer properties of the deposits. When there is a reduction in the heat flux below the set value of a particular sensor, the adjacent two blowers are actuated. The sequence of blowing continues in a sequential manner from wall to wall until the SH spray flow reaches a low set point.

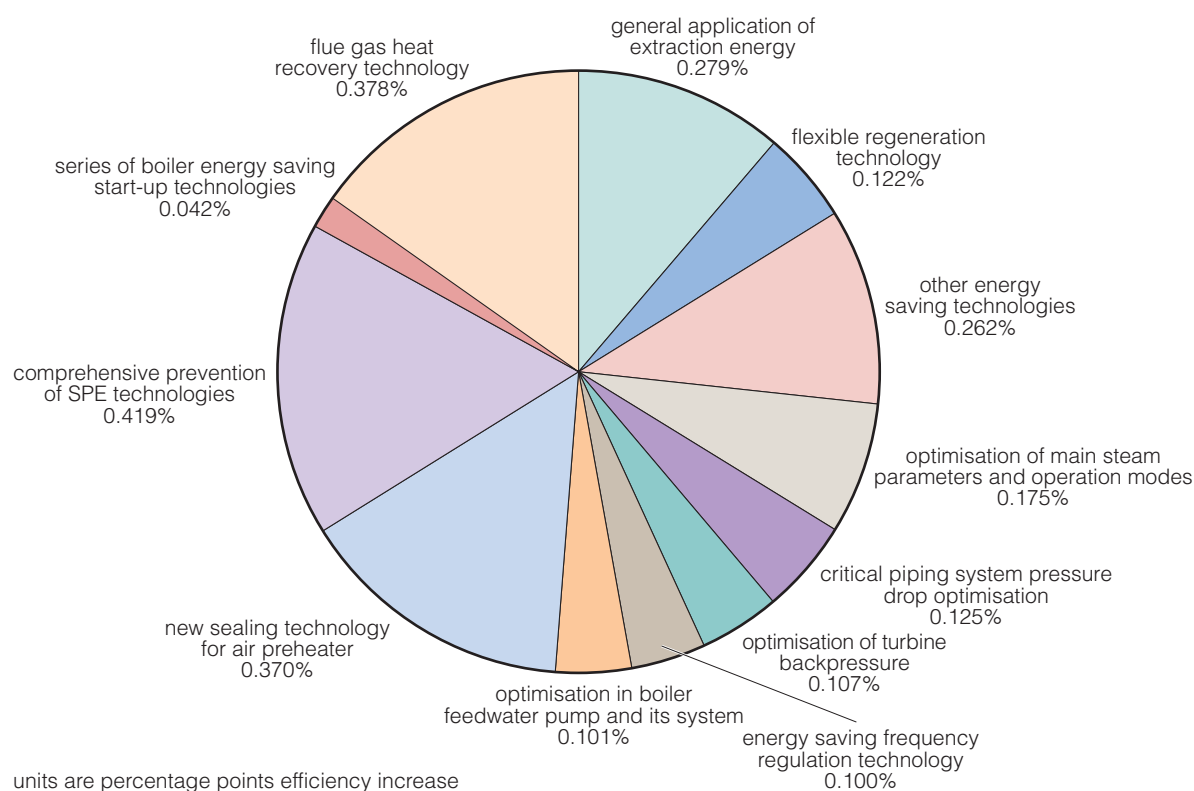
The SWBS resulted in a steady SH/RH steam temperature, giving improved boiler efficiency in addition to reduced superheated steam consumption due to fewer blowings (operation was reduced by about 55–60%) and there was an accompanying reduction in tube erosion.

## 5.22 Monitoring and combustion control optimisation using a laser-based system

Combustion optimisation is important for maintaining maximum efficiency, as discussed in Section 2.1, and recent developments in equipment using a laser system to show the fireball shape were described by Dhubert (2013) and Starke and Williams (2013). Zolo's ZoloBOSS technology, based on Tunable Diode Laser Absorption Spectroscopy (TDLAS), passes laser beams through the furnace between a number of points and spectroscopically analyses the emerging light to monitor the concentrations of H<sub>2</sub>O, CO, O<sub>2</sub>, CO<sub>2</sub> and also the temperature. A typical benefit can be the centring of the fireball in a tangentially-fired unit. Another example is more precise determination of oxygen profiles, enabling elimination of low O<sub>2</sub> areas that cause tube wastage, elimination of high O<sub>2</sub> areas that lower efficiency, and reducing the overall excess O<sub>2</sub> to give boiler efficiency improvements of 0.3–0.75% (Dhubert, 2013). Siemens supplies the technology as part of its process optimisation solutions for power plants. A boiler efficiency increase of 0.42% was reported for a boiler in China (Starke and Williams, 2013).

## 5.23 Waigaoqiao No 3 Plant, China – efficiency enhancements at a modern USC unit

The possibilities for efficiency improvement are not restricted to old power plants. For example, a 4% drop in efficiency in some Chinese SC and USC units after two years has been reported due to solid particle (oxide) erosion of turbines (Feng and Yu, 2012). But other, scarcely recognised, shortfalls in potential performance have very recently been shown to be compensated by use of innovative approaches. The Waigaoqiao No 3 plant in Shanghai has two 1000 MW USC tower boilers of Alstom design, steam parameters 28 MPa/605°C/603°C, constructed by Shanghai Boiler Works, and two 1000 MW Siemens designed turbines, manufactured by Shanghai Turbine Works. The plant was



**Figure 19 Efficiency improvements at Waigaoqiao No 3 USC plant in Shanghai, China (Feng and Yu, 2012)**

opened in 2008. The owners have been active since the start of construction in optimising the design. Efficiency improvements, verified by Siemens (Mao, 2012), have been impressive (*see* Figure 19), and some of the innovations that have been introduced are described below. Further details are in Feng and Yu (2012) and Mao and Feng (2012).

### 5.23.1 Boiler area

Air heater leakages were reduced by installation of flexible seals. The seals follow changes in geometry and have given improved heat transfer and a reduction in fan power. The total gain in efficiency was 0.37 percentage points.

A novel design of heat exchanger using corrosion resistant metals, placed ahead of the FGD, has been installed to achieve low temperature heat recovery from the flue gas. Plastic heat exchange materials, as applied together with corrosion-resistant metals in the same part of some (mainly lignite) plants in Germany (*see* Chapter 3, page 15), were considered too difficult to apply and too expensive. FGD power consumption was also reduced by more than 0.2% of generated power by process and operating mode improvements.

An innovative boiler start-up procedure was developed. Among these was steam heating, using the adjacent unit, to convert a cold start-up to a hot start-up, saving most of the start-up oil and maintaining better flue gas quality and safety. Another example was boiler water filling in static pressure state without starting up the boiler feed pump, and hot flushing in a non-fired mode.

### 5.23.2 Turbine area

Innovative optimisation of the operation mode of the control and overload valves gave significant



advantages. For example, adjusting condensate flow to vary indirectly the flows of extraction steam enabled transient demands to be met without efficiency loss. The main control valves remained fully open and the overload valve closed, thereby eliminating throttling losses. Ramping rates of 15 MW/min were achieved.

The main boiler feed pump is turbine driven. The Alstom boiler feed pump turbine can be supplied with steam from the neighbouring unit for start-up, reducing power consumption during start-up.



**Figure 20** IP turbine blading at Waigaoqiao No 3 after 30 months' operation (Feng and Yu, 2012)

Steam side corrosion of boiler components with associated solid particle erosion of the HP/IP turbine and valves is a known potential issue in the recent USC units in China, as elsewhere, decreasing efficiency markedly with time. At Waigaoqiao No 3, this has apparently been solved. This involved selecting appropriate materials and adjusting the start-up regime and operating strategy to minimise the accumulation of detached oxides in the boiler tubes, as well as ensuring that they can be blown out more effectively when they arise (to the condenser) using higher flushing energies. Figure 20 shows that the IP turbine blading after 30 months had suffered no damage. The approach used here appears conventional, but carefully designed to be very effective.

Further innovations are planned at Waigaoqiao, including a cross-compound turbine design such that the HP/IP unit is mounted at the level of the boiler steam headers, while the LP cylinders remain at ground level. This will reduce pressure drops in the main and reheat steam lines, enhancing efficiency, and reduce the cost of these thick pipes. It is seen as the way forward, particularly for 700°C A-USC units, with their need for very expensive materials for these pipes (Feng and Yu, 2012).

## 5.24 Comments

The examples in this chapter show that upgrading and efficiency improvements are offered by many suppliers. The improvements can not only restore ageing plants to their original performance, but also can often improve them further by avoiding the limitations of the prevailing technology at the time of original plant design. Even some supercritical plants have reached the age where upgrades can usefully be applied to them, and a lesson from the events at Waigaoqiao is that it may be possible even in a new unit to improve efficiency by a significant amount using the same steam conditions by focusing on detailed areas of small potential losses. Not all of these areas have been considered worthy of attention previously, and a conclusion from that is that there may be other unrecognised areas of losses in efficiency which could be worth identifying. The Waigaoqiao No 3 owners believe that they will be able to achieve, with 600°C steam turbines, efficiencies that were considered to be achievable only with future 700°C systems. A point to make here is that it is not known how much additional cost has been involved in producing this outturn of performance improvement at Waigaoqiao No 3 (*see* Figure 19). Hence, application of some of these measures may be precluded in some circumstances, depending on local factors.

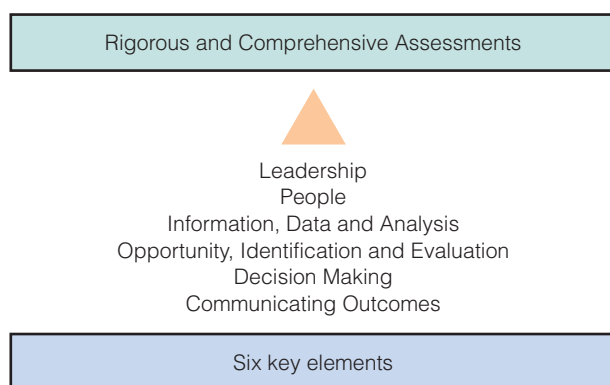
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## 6 Programmes

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National and international programmes to encourage plant improvements are expected to play an important role in moving to lower CO<sub>2</sub> emissions. Some examples are given in this chapter.

### 6.1 Australia's Energy Efficiency Opportunities Program



**Figure 21 Energy Efficiency Opportunities Program assessment framework** (Shoesmith and Dessi, 2012)

Australia's Energy Efficiency Opportunities (EEO) Program is aimed at encouraging large energy-using businesses to improve the identification, evaluation and implementation of worthwhile opportunities to save energy (RET, 2011). The legislation came into effect for large electricity generators in July 2011 (Shoesmith and Dessi, 2012). The philosophy of the programme is to incentivise companies through ensuring that they can see how a payback can be achieved through a whole business consideration of energy usage. Implementation is then left to the companies. The aspects considered are shown in Figure 21.

In order to meet the requirements adequately, for each of these six key elements, a company must (a) explain the aim of that element, (b) list the key requirements, and (c) show evidence that the requirements have been met. First indications from the (still ongoing) process are that there is a lot of data available, but that better measurement and handling of the data could identify areas for improvements in efficiency. The detailed technical areas identified under the EEO Program for efficiency improvement are shown in Chapter 7, on best practices.

### 6.2 Plant renovation and modernisation in India

In India, there are large numbers of coal-fired units above 100 MW capacity that are clear candidates for renovation and modernisation (R&M) to raise their efficiency and availability. The non-reheat units of 100 MW and smaller capacity will be closed, but the overall deficit in power in the country dictates that the great majority of plants be retained. According to the Central Electricity Authority (CEA), in all of India, 18.965 GW of coal-fired units are being renovated under the 11th five-year economic plan (to 2012) and 4.971 GW are being renovated under the 12th plan (to 2017) (Mathur, 2011). The R&M programme is primarily aimed at overcoming problems due to:

- design deficiencies;
- non-availability of spares;
- poor quality of coal;
- environmental regulations;
- safety requirements.

In the past in India, power plant renovation focused mainly on reliability improvement and life extension, but emphasis is shifting to increasing efficiency (Srivastava, 2010). Two to five percentage point improvements are regarded by NTPC as achievable, although opportunities for gains in the higher end of this range would probably be limited in number. The plant areas regarded as the most important for energy efficiency in plants in India are (Srivastava, 2010):

- combustible losses in furnace and ash;
- excess air control;
- final flue gas temperature at air heater outlet;
- feed water temperature;
- water chemistry;
- leakages of steam/water leading to additional water make-up;
- boiler insulation;
- condenser vacuum;
- turbine steam parameters;
- reheat attemperation;
- removal of Bauman stage in LMZ turbine sets (Baumann LP turbines tend to be subject to severe erosion and efficiency loss).

Table 14 shows the expected benefits from improving a typical 210 MW unit (Srivastava, 2010).

Description	Pre R&M	After R&M (target)	Improvement,%
Turbine heat rate, kJ/kWh	9378	8374	12
Boiler efficiency, %	82–84	85	
Unit heat rate, kJ/kWh	11304	9630–10467	7–14
CO <sub>2</sub> emissions, g/kWh	992	848-918	7–14

Issues identified by Srivastava (2010) for consideration in implementing R&M schemes include:

- whether to go to OEM or open tender;
- whether to adopt turnkey concept or owner design with multi-contract procurement;
- whether to modify units simultaneously or progressively to check benefits are being realised;
- scheduling;
- guarantees, penalties, scope widening, cost overrun and delays;
- pressure to keep online;
- rapid obsolescence of control and instrumentation system;
- role of regulator as a catalyst and enabler;
- poor financial health of power utilities;
- establishing techno-economic viability;
- complexity and cost of complying with environmental requirements.

### 6.3 USAID CenPEEP programme in India

The United States Agency for International Development (USAID) assisted NTPC in India in establishing the Centre for Power Efficiency and Environmental Protection (CenPEEP) in 1994. Under the programme, experts from the US Department of Energy and utilities have worked with NTPC in implementing various routes to improve efficiency through technology demonstrations, better maintenance from improved monitoring and performance test systems, as well as associated measures including information dissemination and training (Smouse, 2012). Figure 22 shows the scope of CenPEEP.

Figure 23 shows a breakdown of the efficiency loss areas typically found in Indian power plants. Availability and reliability improvements were seen as key areas to achieve sustained CO<sub>2</sub> emissions reductions.

**Technology Demonstrations**

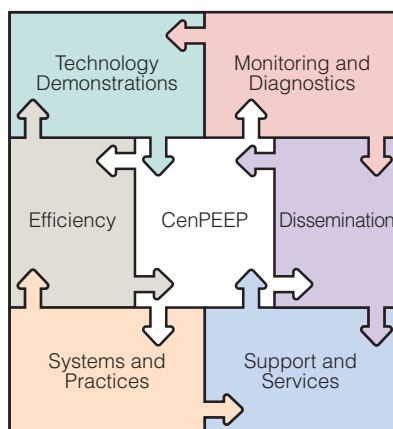
- condenser water powered tube cleaners
- helium leak detector for condenser air-in-leak
- dirty pitot and rotary probe for mill
- boiler performance assessment and optimisation
- infra red thermography, acoustics and videoscope for diagnostics
- thermodynamic modelling for performance analysis
- ultrasonic techniques for feedwater flow measurement

**Monitoring and Diagnostics**

- predictive maintenance
- reliability centred maintenance
- risk evaluation and prioritisation
- financial risk optimisation

**Efficiency**

- accurate test instruments
- simplified subsystem performance test
- user friendly system – portable data acquisition systems, computational software, tapping location, etc
- periodic gap assessment and action plan



**Dissemination**

- workshops – efficiency and monitoring and diagnostics
- guidelines on technology
- performance optimisers, CenPEEP times, portal on intranet
- best practices on overhaul

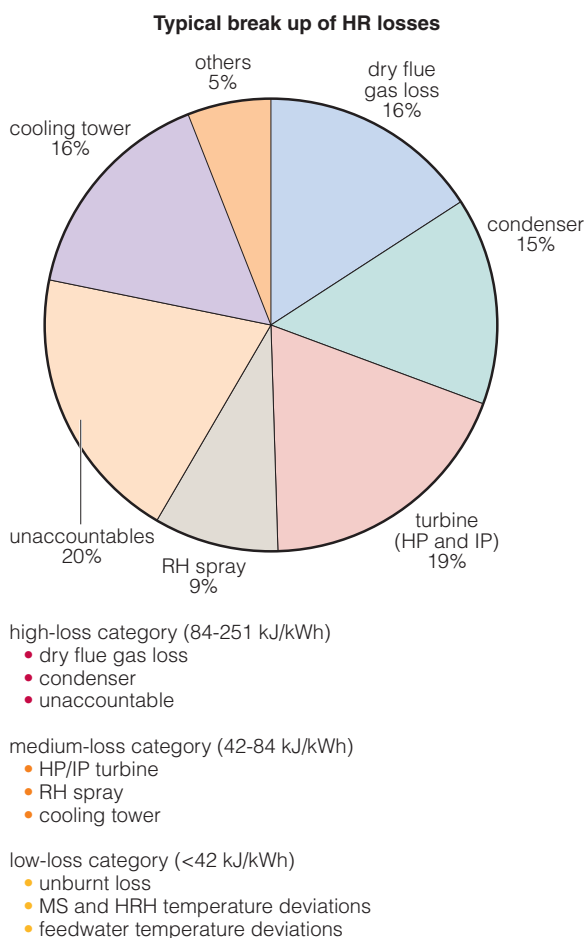
**Systems and Practices**

- energy and efficiency management system
- overhaul preparedness index
- knowledge-based maintenance

**Support and Services**

- customised training programmes
- support to state utilities
- consultancy assignments
- capability and skill building – hands-on training and demonstrations

**Figure 22 USAID-NTPC CenPEEP initiative (Smouse, 2012)**



**Figure 23 Typical efficiency loss areas in Indian PCC plants (Smouse, 2012)**

CenPEEP has also worked with the Asia Pacific Partnership on Clean Development and Climate (APP – see Section 6.5) at three plants in India on technical implementations (see Table 15), as well as other plant surveys, workshops, production of an extensive best practices manual (APP, no date) and providing training in the USA.

The CenPEEP measures have allowed over 90 Mt of CO<sub>2</sub> to be saved over 16 years, with these gains being maintained. However, a key challenge area that remains in India is a lack of service providers for maintaining the fleet. This needs addressing urgently to provide future support for the supercritical plants that are being constructed throughout India (Smouse, 2012).

## 6.4 India's Partnership in Excellence (PIE) Programme

Also in India, the Partnership in Excellence (PIE) Programme was introduced to tackle both the technical and non-technical factors that were responsible for very low plant load factors (PLF, known outside India generally as

Table 15 Technical implementations at three Indian PCC plants (Smouse, 2012)		
Kolaghat	Ropar	Tuticorin
Gravimetric feeders re-calibrated – OEM	Fuel air damper operation restored	Boiler casing and ducts repaired
RH Spray line commissioned	Burner tilts commissioned	Penthouse roof & furnace enclosure repaired
HP heater 5 taken in service for 1st time	RH spray reduction by regular sootblowing	SH/RH spray measurement provided
Aero foils installed for PA measurement	Boiler insulation restored	One ejector taken out of service
Additional O <sub>2</sub> probes installed	Mill classifiers restored for improved PF fineness	PF orifices replaced
Gas duct expansion joints replaced	Additional O <sub>2</sub> probes installed	Additional O <sub>2</sub> probes installed
Wind box – insulation replacement	Tests for monitoring air ingress	High energy drain valves replaced
Ejectors for economiser hopper ash evacuation	Fuel air ratio optimisation	High energy drain downstream temperature monitoring provided
Sootblowers being commissioned	Test ports provided	Test ports provided
Test ports provided		

capacity factor) – 26 plants were selected for this programme (Goswami and others, 2009). These authors also described the constraints that have to be considered for improving the performance. Issues include the difficult coals (*see also* the IEA Clean Coal Centre report: Henderson, 2003, for case studies centred on coal quality effects at three power plants) and plant maintenance (also described in the above report), but non-technical issues can also be important. Apart from the obvious financial resource constraints, there may be cultural difficulties at some power plants that give rise to ingrained resistance to, for example, adopting updated maintenance systems or giving sufficient consideration to changes that would be aimed at energy conservation. The PLF was improved significantly at many of the 26 plants. Changes in efficiency were not detailed in the paper.

## 6.5 Asia-Pacific Partnership on Clean Development and Climate

The Asia-Pacific Partnership on Clean Development and Climate (APP) was referred to in Section 6.3 on USAID. Although the organisation's work formally concluded in 2011, a number of individual projects will continue under the aegis of other co-operation organisations. One of these is the GSEP Power Working Group, described in Section 6.6. Among the activities of the APP was promoting best practices within the power industry, and an important item was the co-operation with USAID in production of a best practice manual for India by its Task Force on Power Generation and Transmission (APP, no date).

## 6.6 Clean Energy Ministerial Global Superior Energy Performance Partnership (GSEP)

The Clean Energy Ministerial (CEM) is a high-level global forum to promote policies and

programmes that advance clean energy technology, to share lessons learned and best practices, and to encourage the transition to a global clean energy economy. Initiatives are based on areas of common interest among participating governments and other stakeholders. The Global Superior Energy Performance Partnership (GSEP) has been established within the CEM to foster energy efficiency improvements. The Power Working Group of the GSEP, consisting of leaders from the public, private, and academic/research sectors, exists to exchange information and create practical projects through public-private partnerships. One of the areas for co-operation will be on efficiency and environmental performance improvements at existing power plants. The Working Group is building upon work introduced under the APP Power Generation and Transmission Task Force, described in Section 6.5. Among its activities, the Working Group is working with the technology providers to identify best practices for power generation, quantifying the potential energy savings and emissions reductions from applying them, and facilitating investments in projects employing best-available technologies as identified through activities of the Working Group (GSEP, 2013).

## 6.7 China's incentive policy on upgrading and efficiency improvements

In June 2012, China's government announced a new policy to upgrade and improve the efficiency of its older existing coal-fired power plants through boiler and turbine retrofits (Hu, 2013). Qualifying units have to meet the following prerequisites:

- capacity between 100 and 1000 MW;
- operation time of the retrofitted unit should be over two years and, for units of under 200 MW, the operation time should be less than 15 years, except for retrofitting for heat supply;
- the retrofit of a unit should give at least a 7500 tce saving per year.

The following incentive measures have been introduced:

- for each 10,000 tce saved, a 30,000 kW capacity credit will be awarded to the company for building new coal-fired power units;
- for each 10,000 tce saved, RMB3 million will be awarded;
- commercial bank loans will be available at a favourable interest rate;
- retrofitted units with 'distinctly' higher efficiency will be preferentially dispatched.

The dispatch preference is interesting, as much of the coal-fired capacity in China, except in a few provinces, operates at an approximately similar capacity factor, regardless of efficiency. However, in a few provinces a dispatch order is operating (under the Energy Conservation Power Generation (ECPG) scheduling programme). Nationwide introduction is still awaited (Minchener, 2010; Henderson and Baruya, 2012; Hu, 2013).

More than 500 coal-fired units, with an installed capacity of over 200 GW, are currently engaged in upgrading and efficiency improvement works. By 2015, more than 800 units, with a total capacity of over 350 GW, are expected to have carried out or to be in the process of carrying out, upgrading works. The estimated saving in coal consumption will be more than 14 Mtce, and the reduction in coal consumption over 7 g/kWh (Hu, 2013). This appears to be a rather conservative estimate, being equivalent to around only a 0.5 percentage point increase in efficiency, and consideration of the case studies in Chapter 5 suggests that the benefits may turn out to be greater than this.

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## 7 Best practice in plant upgrading and improvement

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In this chapter, best practices for achieving performance improvements from existing coal-fired plants are summarised. Figure 1 on page 8, from an earlier IEA Clean Coal Centre report, showed those areas of a PCC unit that can give rise to efficiency loss.

Some of these losses can be minimised through better operational practices. As well as directly minimising, for example, combustible losses, good practice will also provide the data needed for applying condition-based maintenance effectively. Condition-based maintenance will in turn improve plant availability and efficiency and involves monitoring of important plant parameters, some on a continuous basis, others on a periodic basis. The following lists, based on suggestions by Goswami and others (2009) for Indian plants, are generally applicable.

Concerning operational practice, continuous monitoring is needed in the following areas:

- temperature, pressure and flow of air-fuel mixtures at all burners to ensure homogeneous mixing and balanced firing;
- flue gas temperature, flow and oxygen and CO contents;
- steam parameters and flow;
- vibration monitoring of critical rotating equipment including pulverising mills, turbines, fans, pumps.

In addition to the above tasks, periodic monitoring is needed in the following areas to identify developing areas of potential future failure as well as declining efficiency:

- boiler tube thickness measurement;
- vibration measurement of less critical rotating machinery;
- detailed vibration analysis of turbine for detection of misalignment, lack of balance, etc;
- temperature measurements on valve bodies;
- identification of valve leakage by acoustic and other means;
- boiler feedwater quality;
- condenser vacuum;
- records of data for trend analysis.

Table 16 gives a more extensive list taken from the many detailed technical areas for improvement that have been identified within Australia's EEO Program that was described in Chapter 6 (Shoosmith and Dessi, 2012). Best practice will entail considering all of these areas for relevance to the plant in question. Naturally, not all will be applicable, and, of those, not all will reveal a need for improvement. Many of those under the headings 'fuel based efficiency opportunities' and 'boiler based efficiency opportunities' are within the better operation and maintenance category, where there may be shorter term operational and maintenance (O&M) changes that can improve performance without major capital expenditure to give a return on investment. A key lesson from the EEO has been that performance should be assessed at actual operating loads. Most within the 'steam/water cycle based efficiency opportunities' and 'auxiliaries based efficiency opportunities' fall within the category of plant improvement projects (retrofits).

The focus of this report is mostly on retrofits, which are typically substantial projects to restore units to close to, or even better than, design performance. For these fairly capital intensive projects, it is first necessary to prioritise the plants to identify which ones in which to invest. A selected plant should have potential for long life, secure fuel availability and high future capacity factor (within reasonable expectations, given market and regulatory uncertainties). Increased efficiency, with resultant lower fuel costs will probably improve the plant utilisation, which, by itself implying an increased load factor, will maximise the efficiency. Thus, when evaluating improvements available from changes to plant it is necessary to establish the likely net result of these interactions.

The first step of an improvement programme is to assess the current situation. The plant should have a good track record of competent management in the past, so that there is a certainty of being able to depend on future performance monitoring and maintenance. A recent history of plant faults must be examined closely to assess the prospects of achieving sustainable improvements. The improved plant must have a future-proof environmental control strategy, including acceptable outlets (disposal or markets) for solid outputs. A thorough plant examination is then required, including current performance measurements. If 50% of systems would need replacement within a few years, a new plant, perhaps retaining only civils and utilities, will be more appropriate.

An APEC report published in 2005 (Boncimino and others, 2005) recommended the following plan for implementing upgrading and refurbishment activities once the plant has been selected:

- conduct a plant assessment to identify the highest priority plant improvement options;
- from the above, select the equipment improvements to be analysed in detail; the selection should be based on feasibility, available funding, cost benefits, and operational considerations;
- complete a detailed analysis which provides estimates of performance improvements (including CO<sub>2</sub> reductions), capital costs, operational and maintenance cost differences and reliability improvements.

Table 16 from the Australian Energy Efficiency Opportunities Program, as already discussed, provides a comprehensive check-list of suggested areas for reviewing. Performance indicators for major equipment areas are shown in Table 17, taken from the APEC report also cited earlier (Boncimino and others, 2005). This forms a listing of guideline criteria for major equipment areas where a shortfall can markedly impact on performance. This is suggested as a guideline for conducting the initial evaluation. It is followed by assessments of availability, operations and maintenance (O&M) practices and emissions for the major plant areas, reproduced as Table 18. Following the latter, the plant owner then carries out economic and financial evaluations of potential improvement actions. The APEC report contains (theoretical) example projects to illustrate the process. The final step before implementation is to prioritise the improvements according to the estimated efficiency, emissions, reliability, operational and financial benefits.

The examples in Chapter 5 showed that there is extensive expertise and experience available among the major suppliers of new plants and other companies involved in retrofit work. Projects have been realised on schedule or ahead of time, and gains in efficiency and output have been substantial, as predicted during the project definition stages. The figures and tables in Chapter 6 showed the maintenance, monitoring, performance testing, technical implementations and training that are capable of giving major improvements also.

## 7.1 Cost-effectiveness of coal plant upgrading in comparison with renewables

Alstom (a supplier of both fossil- and renewables-based technologies) has compared the cost of increasing the output of a coal-fired plant through efficiency improvement with that of building various types of renewable energy plants (Atkins, 2012; Davies, 2013). Even using quite conservative assumptions, the former was found to be much more favourable in terms of calculated levelised cost of electricity. One of the reasons for this was the lower capacity factor expected for most of the renewable energy options than for a base load coal-fired unit. This, together with the large capacity of coal-fired power generation that is expected to persist for some time, demonstrates the value of a global strategy for CO<sub>2</sub> emissions reduction encompassing use of both renewables/non-fossil energy sources and coal plant efficiency improvements.



**Table 16 Energy efficiency opportunities (Shoosmith and Dessi, 2012)**

Fuel based efficiency opportunities	Use higher quality coal
	Use lower ash coal
	Achieve consistent coal quality
	Better coal quality measurement
	Use waste heat for coal drying
	Monitor real time cost/consequences of coal quality
Boiler based efficiency opportunities	Reduce air leaks
	Waste heat recovery
	Reduce steam/water leaks
	O <sub>2</sub> trimming
	Performance monitoring
	Reduce fouling
	Upgrade air heaters (reduced leakage, improved heat transfer)
	Improve mill performance
	Trend boiler efficiency
	Tune boiler control system
	Better heat transfer in tube banks – design
	Excess air optimisation; O <sub>2</sub> and CO probes
	Monitor air and fuel flows to each burner for combustion optimisation
	Improve maintenance – schedule and implementation
	Optimise sootblowing
Training for operators	
Steam/water cycle based efficiency opportunities	Upgrade/reinstate HP heaters
	Reduce cooling water inlet temperature (condenser, cooling tower improvements)
	Waste heat recovery
	Optimise feed heating
	Upgrade cooling tower packing
	Turbine upgrades (more efficient 3-D blading, diaphragms, etc)
	Install new high efficiency seals/glands/retractable packing
Auxiliaries based efficiency opportunities	Variable speed drives
	Increase use of smart instrumentation
	Improve monitoring instrument quality/calibration
	Auxiliary operation practice – training for operators
	Improve mill efficiency
	Optimise use of conveyors/plant

<b>Table 17 Equipment performance indicators (Boncimino and others, 2005)</b>			
Equipment	Key Operations and Economic Performance Indicators		
	Indicator 1	Indicator 2	Indicator 3
Air heater	Air leakage more than 5% to 10% above design or above 20% in any case	Gas inlet to outlet temperature difference within 15°C to 20°C of design or above 170°C in any case	Air temperature to the pulverisers and burners that is lower than design by about 20°C to 30°C. Pulveriser output limitations based on insufficient air temperature may need to be considered
Pulverisers	Overall 100% output within 10% of the design value with applicable adjustments for coal grindability and moisture	Coal fineness less than 10% below design value; For example, 60% versus 70% passing a 200-mesh screen based on the current coal and unburnt carbon and furnace slagging within reasonable limits	Coal spillage from the pulveriser pyrites discharge is minimal. Reasonably uniform coal and air flow to the burners. Adequate rejection and removal of pyrites
Burners	Flame length, colour and position are proper; and no pulsation or vibration	NO <sub>x</sub> emissions are within 10% of design value and below the environmental air permit requirements	In conjunction with the air heater and pulveriser operation, excess air, for example, less than 25% is achieved with acceptable furnace slagging and other boiler operation requirements
Sootblowers	Furnace wall, superheater, reheater, and economiser surface cleanliness is within the boiler supplier's recommendations	Furnace exit gas temperatures and flue gas temperature entering the superheater and other heat exchange surface sections are within the boiler designer's acceptable range	Erosion of superheater and other surfaces is not causing tube failures due to the sootblower operating frequency, location or steam moisture
Steam turbine	The results of a turbine test (for example: ASME Performance Test Code 6) with the design heat balances should show that the tested heat rate is within 4% of design	The results of a turbine test should show that current maximum output is within 2% of the design output	The results of a comparison of turbine test results with new turbine components is within 4% of the new turbine design or the maximum expected output. Also, the type of turbine (for example, partial or full arc) is compatible or optimum for the planned unit operation
Condenser	Operating pressures are high because of scaled tubes, excessive number of plugged tubes or air leakage into the condenser	Cooling water leakage into the condenser results in poor water quality to the boiler and steam quality to the turbine	Inadequate cooling water flow because of pump deficiencies, water intake or discharge problems, and excessive piping pressure loss. Also, increased cooling water supply pressure from the river, cooling tower or other source

**Table 18 Availability, operations and maintenance (O&M) and emissions indicators for major plant areas** (Boncimino and others, 2005)

Major plant area	Availability	O&M	Emissions
Boiler	<p>Better than 90% availability</p> <p>Water and steam tubing temperatures are monitored as needed and are not excessive</p> <p>There is a programme for steam drum and main headers non-destructive testing (NDT) examinations based on the age of unit, materials and operating conditions</p>	<p>Operating staff follows manufacturer's startup, shutdown and other operation manual recommendations to control fuel consumption</p>	<p>Emissions (NO<sub>x</sub>, CO) are no more than 5% greater than the contract performance values or for similar units firing similar coal</p>
Turbine generator	<p>Better than 95% availability</p> <p>Steam supply temperatures and quality is within equipment supplier's recommendations</p> <p>There is a programme for shaft, blade and other NDT examinations based on the age of unit, materials and operating conditions</p>	<p>Operating staff follow manufacturer's start-up, shut-down and other operation manual recommendations to control thermal stresses</p>	<p>Not applicable</p>
Condenser	<p>Condenser tube plugging and leaks are not occurring resulting in less than 99.5% average availability</p>	<p>Tube scaling and water thickness measurements show no major deterioration. Tube plugs are mapped to show if there are failure trends that need to be investigated</p>	<p>Not applicable</p>

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## 8 Summary and conclusions

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Many coal-fired power plants operate at low efficiencies because of deterioration of components or decrease in coal quality or both. The result is that more CO<sub>2</sub> is emitted from these units per unit of electricity supplied than need be the case. The losses that develop in the earlier part of the life of a plant are generally containable by employing good operating and maintenance practices. However, after about 25–30 years of operation, performance and reliability will usually have decreased to the extent that substantial works, known as retrofits, may be merited, in order that the unit may be restored to operating efficiently and economically. Potentially all areas of plants could be improved, including boiler, turbine, non-process area plant and auxiliaries. There is a large number of older coal-fired power plants worldwide that could potentially be retrofitted to give major reductions (hundreds of Mt/y) in CO<sub>2</sub> emissions. Improvement measures are generally cost-effective, because of fuel savings, availability increase and plant life extension, and, in some countries, CO<sub>2</sub> emissions cost savings.

The lower performance of older plants also stems from the limitations of the prevailing technology at the time of plant design. Modern steam turbines use features such as sophisticated blade profiles that give considerably higher efficiency and output than those of 30 years ago, even using the same steam conditions and flow rate. Retrofitting modern technologies on them will increase performance significantly, or compensate completely for loss of net efficiency from addition of environmental control equipment after a plant was first commissioned. As an example of the latter, the annual average efficiency in 1982–83 of the first three units of Drax power station in the UK with no FGD was 37.1% HHV, net (Electricity Supply Handbook, 1984). This is equivalent to around 39% LHV. The turbine retrofit work described in Section 5.18 has now increased the efficiency to almost 40% LHV even with FGD (Drax Group, 2012). Annual operating efficiency will probably be a little lower than this, but comparable with the 39%. Major plant upgrading involving conversion of subcritical to supercritical or ultra-supercritical (USC) could raise efficiencies more substantially but has seldom progressed beyond studies because of the high cost.

Although there are large numbers of ageing coal-fired power plants everywhere, the impact of plant ageing on efficiency tends to be most significant in countries where financial resources for maintenance are limited. So, for example, there tend to be serious shortfalls in plant performance in the non-OECD countries of Southeast Asia. Also, because realisable efficiencies are also lower in this region than in cooler climates, it is particularly important to maximise efficiency by retrofitting. In contrast to OECD countries, where the turbine is generally the major area of equipment most likely to need upgrading, it is equally common to see deterioration in the boiler and associated systems.

Retrofits are the main subject of this report, but optimisation of the combustion process can give valuable benefits in efficiency and costs. The gain may typically be about 0.1–0.15% in fuel cost saving, efficiency and CO<sub>2</sub> emissions. It has also been speculated that there may even be an unrecognised potential additional economic value, through improved availability, life extension and maintenance costs. Improvements in combustion efficiency can be achieved in parallel with other improvements, for example, reductions in primary NO<sub>x</sub> production from replacement burners and new air supply arrangements. Intelligent sootblowing systems that monitor the condition of key parts of the boiler and control sootblower operation accordingly can improve boiler efficiency by 1% or more and reduce the incidence of outages from fouling.

Lignites with inherent moisture contents as high as 50–65% are used for power generation in some countries. The systems that use these coals extract furnace gas from the boiler to evaporate the moisture and convey the lignite and water vapour to the burners. This restricts generation efficiency, leading to higher CO<sub>2</sub> emissions than from plants firing lower moisture coals. Lignite pre-drying, to keep this moisture out of the boiler, would give a potential efficiency advantage of about

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four percentage points if a boiler designed for the dryer feed were used. Retrofitting a pre-dryer to treat a maximum of about 25–30% of the fuel feed to an existing boiler would be possible, and would give a worthwhile one percentage point efficiency gain. Such dryers, which use low-grade heat as energy input, are at the point of commercial availability.

Programmes to drive efficiency improvements of coal fleets are important and some are described in the main body of the report (for example, Australia's Energy efficiency Opportunities Program and the USAID CenPEEP programme in India and India's Partnership in Excellence (PIE) Programme). Notably, China has recently set up a major programme providing incentives for plant owners to carry out upgrading and efficiency improvements through retrofits, with a total capacity of over 350 GW expected to have been improved or to be undergoing improvements by 2015.

Many companies provide efficiency improvement and upgrading services. A major chapter of the report contains a number of case studies in South Africa, Indonesia, India, Poland, Germany, USA, Australia, UK and China. Most are major retrofits of old units, but the last case study, from China, is an interesting example of relentlessly pursuing all the smaller potential losses in a new USC plant, to push efficiencies higher, by focusing on detailed areas, including areas not previously recognised as worthy of attention. A conclusion from that is that there may be other unrecognised losses capable of being reduced.

Another chapter of the report summarises best practice in plant upgrading and improvement. This will also provide the data needed for applying condition-based maintenance effectively, involving monitoring of important plant parameters. Before retrofits, it is first necessary to identify which plants in which to invest. A selected unit should have potential for a long life, secure fuel availability and high future capacity factor. It should have a good track record of competent management, and the recent history of plant faults must indicate good prospects of achieving sustainable improvements and a future-proof environmental control strategy with secure outlets for waste streams as by-products. A thorough plant examination is then required, including current performance measurements. In planning the upgrading and refurbishment activities, it is then necessary to select the equipment improvements to be analysed in detail with estimates of performance improvements and costs.

Overall, this report shows that environmental and economic benefits are routinely achievable from plant modernisations and that the potential gains are now very considerable. Progress is being made to realise these gains through projects at increasing numbers of plants. Technology sharing between all countries will be valuable in increasing the benefits.

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