Increasing the flexibility of coal-fired power plants

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Preface

This report has been produced by IEA Clean Coal Centre and is based on a survey and analysis of published literature, and on information gathered in discussions with interested organisations and individuals. Their assistance is gratefully acknowledged. It should be understood that the views expressed in this report are our own, and are not necessarily shared by those who supplied the information, nor by our member countries.

IEA Clean Coal Centre is an organisation set up under the auspices of the International Energy Agency (IEA) which was itself founded in 1974 by member countries of the Organisation for Economic Co-operation and Development (OECD). The purpose of the IEA is to explore means by which countries interested in minimising their dependence on imported oil can co-operate. In the field of Research, Development and Demonstration over fifty individual projects have been established in partnership between member countries of the IEA.

IEA Clean Coal Centre began in 1975 and has contracting parties and sponsors from: Australia, Austria, Canada, China, the European Commission, Germany, India, Italy, Japan, New Zealand, Poland, Russia, South Africa, Thailand, the UK and the USA. The Service provides information and assessments on all aspects of coal from supply and transport, through markets and end-use technologies, to environmental issues and waste utilisation.

Abstract

Increasingly, coal-fired power plants are required to balance power grids by compensating for the variable electricity supply from renewable energy sources. For this, high flexibility is needed, in terms of possessing resilience to frequent start-ups, meeting major and rapid load changes, and providing frequency control duties. This report reviews the means available and under development for achieving flexibility. Potential damage mechanisms are well known, and the necessary flexibility can be achieved with acceptable impacts on component life, efficiency and emissions. Designs are being developed to enable flexibility in future plants.

Acknowledgement

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Acronyms and abbreviations

ABS	ammonium bisulphate
ASU	air separation unit
A-USC	advanced ultra-supercritical
CFBC	circulating fluidised bed combustion
ESP	electrostatic precipitator
FDBR	Association of Plant Engineering for Energy, Environment and Process Industry (Germany)
FGD	flue gas desulphurisation
GW	gigawatts
HP	high pressure
IEA	International Energy Agency
IEA CCC	IEA Clean Coal Centre
IGCC	integrated gasification combined cycle
IP	intermediate pressure
LHV	lower heating value
LP	low pressure
MCR	maximum continuous rating
MPa	megapascals
MW	megawatts
PCC	pulverised coal combustion
PID	proportional integral derivative
RH	reheater
SCR	selective catalytic reduction
SH	superheater
SNG	substitute natural gas
USC	ultra-supercritical

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1 Introduction

A recent report from the IEA Clean Coal Centre discussed the growing capacity of renewable energy plants around the world and the effects of their intermittent and highly variable output on the operation of coal-fired plants (Mills, 2011). In the absence of sufficient large-scale electricity storage capability, the effect has been to force coal (and gas) fired units in some countries to deliver greatly varying output to enable the grid system to meet load at all times. The challenges presented by this situation will only increase and become more widespread in the future. For example, Hitachi Power Europe (now Mitsubishi Hitachi Power Systems) has estimated that fluctuations in supply in Germany from renewable power sources will double or triple by the end of the decade, while the demand for electricity from non-renewable sources will have decreased by 50% between 2010 and 2020 (Schultz, 2012). This is against a background of ever-changing system demand during each day (Balling, 2010). A comparison of the 2010 position in Germany with a projection for 2020 in Figure 1 illustrates the magnitude of the expected challenge (Busekrus, 2012).

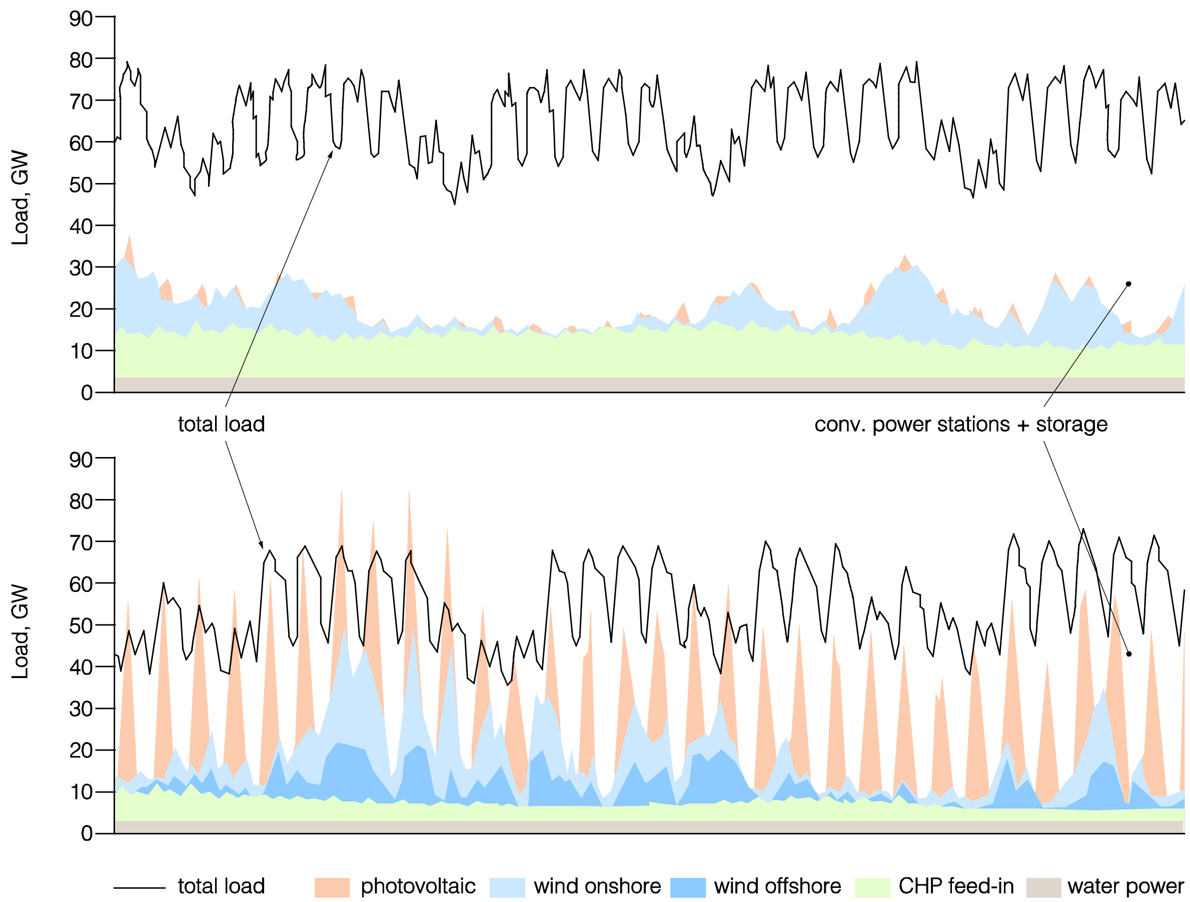

Figure 1 Monthly pattern of load and generation for Germany in 2010 (upper) with prediction for 2020 (lower) (Busekrus, 2012)

There is a wide range of reported values in the literature for the maximum load following rates of coal-fired units. One reason behind this may be that actual and design values can differ. Another reason is that some literature describes the characteristics of one major area of the plant only, for example the steam generator but not the turbine. Another contributing reason may be a lack of clarity sometimes in whether values refer to the normal load ramp rate capability as opposed to the capability for providing transient output changes to provide grid frequency control – *see later in this chapter*.

Once-through steam generators should in principle be capable of changing load more rapidly than boilers with steam drums. The twin Neurath 1.1 GW lignite-fired once-through USC units recently put into commercial operation in Germany can each change by 500 MW in 15 minutes (Fairley, 2013). This is about 3%/min based on MCR (maximum continuous rating). However, it can be possible to exceed this even with some existing plants, depending on design: 5% of maximum load/min was cited some years ago for a 220 MW unit in the USA after control system changes and tuning (Blankinship, 2003). In this report, as is normally the case in papers citing load change rates, % values are referring to % of maximum load. So, for example, a ramp rate of 2%/min on a 1000 MW plant is a linear 20 MW/min rate of change, whether from 400 MW or from 900 MW.

A presentation by Hitachi (now Mitsubishi Hitachi Power Systems) gives a rate of 7%/min from 40% to 100% output for the steam generators of new hard coal or lignite-fired plants (Busekrus, 2012), while brochures by the company suggest even 10%/min is possible (MHPS, 2014a,b). Babcock Power have reported 7%/min as a typical design value for a once-through boiler in the load range 50–90%, with demonstrated operating experience at this value with the 550 MW bituminous coal-fired unit at Rostock, Germany in two-shifting mode (Vitalis and others, 2000).

Some values from a survey and review conducted by Lindsay and Dragoon (2010) are shown in Table 1, to illustrate the potential for confusion in establishing a representative value for existing practical ramp rates. The EPRI data within that table were from a survey by that organisation of a large number of units in 1982, and, although old, do show considerable differences between maximum and average plant ramping rates, probably indicating a desire to limit plant wear, although there may be other influencing factors. In any case, it is likely that much higher load ramp rates will be required for future large units connected to grids for which the proportion of renewable generation sources continues to climb.

Table 1 Some design and reported plant load ramp rates for coal-fired units (Lindsay and Dragoon, 2010)

		Ramp rate, %/min	
Subcritical	Design	3–5	
Supercritical	Design	7–8	
Reported (EPRI)		**Average**	**Maximum**
Subcritical	180 MW	1.8	3.6
	300 MW	2.0	3.1
	420 MW	1.1	2.9
	540 MW	1.7	2.8
	660 MW	1.3	3.7
Supercritical	420 MW	1.3	4.3
	540 MW	1.1	3.6
	660 MW	1.2	2.0
	780 MW	0.9	3.5
	900 MW	1.0	2.0

The information shown in Table 2 on flexibility characteristics of modern USC PCC and IGCC plants is extracted from a table in a paper based on a study by Foster-Wheeler for the IEA Greenhouse Gas R&D Programme.

Table 2 Flexibility features of power plants (Domenichini and others, 2013)

	Turndown	Cycling capability, start-up to full load	Ramp rate
USC PCC	Minimum boiler load: 25–30%	Very hot start-up: <1h Hot start-up: 1.5–2.5 h Warm start-up: 3-5 h Cold start-up: 6-7 h	30-50% load: 2–3%/min 50-90% load: 4–8%/min 90-100% load: 3–5%/min
IGCC	Minimum environmental GT load: 60%. Process unit/air separation unit (ASU) cold box minimum load: 50%. ASU compressor minimum load: 70%	Cold start-up: 80-90 h Gasification hot start-up: 6-8 h ASU hot start-up: 6 h	Gasification ramp rate: 3–5%/min ASU ramp rate: 3%/min

The indications from the above review are that units can be supplied that can provide higher ramp rates than might commonly be supposed, and that part of the reason for this could be that owners have tended to operate their plants conservatively in this respect. However, an even greater degree of flexibility is expected to be required from coal-fired units in future. The present report focuses on the methods that have been developed to enable them to operate in this manner with least detriment to integrity, efficiency and emissions. It also describes means to achieve systems capable of operating at lower than current loads, so minimising the need for on/off operation or support firing.

Power grids have to maintain their alternating current frequency within defined limits. The synchronous capacity (coal, gas and nuclear) on a grid forms an inertial mass that provides a natural resistance to changes in that frequency when step changes in load or generator trips occur. However, the system also has to have active support to re-match supply to demand within seconds so that the system frequency can be quickly restored after it has begun to change. This primary frequency support function is provided by requiring some plants to be designed and operated in a manner to allow the supply of increased or reduced power on a very short-term reactive basis. This function has to be supplied by synchronous plants, typically some gas and some coal units. The high proportion of intermittent-service renewable energy plants on some grids is resulting in a reduction in the inertia of these grids because such plants do not normally deliver frequency control (Tielens and Van Hertem, no date). As a result, an increasing proportion of a decreasing body of fossil-fired units is now having to provide the service.

Primary frequency control requires extremely fast-changing output capability, for example approximately 1% of rated load per second, although it is needed only over short periods of time. Fossil-fired plants conventionally provide primary control through the turbine governors, which give a response to stabilise the frequency within 10 seconds to a minute, although there are other methods that can be even faster. Secondary control from other synchronous capacity within the grid system then restores frequency over a timeframe of 1–10 minutes (NERC, 2011). Providing frequency control capability in coal-fired units is discussed in Section 4.4.

This report mostly concentrates on pulverised coal (PC) plants, since these constitute the largest fraction of coal-fired generation capacity around the world. Circulating fluidised bed combustion (CFBC) plants form a much smaller, although growing, proportion. Many of the issues discussed around the steam cycle and steam turbine systems for PC plants are likely to be similar for CFBC. Integrated coal combined cycle (IGCC) systems are small in number, but further ones are planned. Later chapters in the report look at the expected flexibility of plants using these technologies.

The report is organised as follows. Chapter 2 considers the potential detrimental effects, particularly on the boiler and turbine areas, of plants operating flexibly. Chapter 3 describes technical measures that have been developed for increasing flexibility in boilers. Chapter 4 examines the turbine and water/steam systems with respect to means for increasing flexibility. Chapter 5 looks at other areas, including emissions control systems and auxiliaries. Chapter 6 covers control systems and flexibility, while Chapters 7, 8 and 9 consider other types of coal-fired plants: CFBC (circulating fluidised bed combustion), IGCC (integrated gasification combined cycles) and A-USC (advanced ultra-supercritical – 700°C and hotter – PCC systems). Chapter 10 discusses the potential flexibility of carbon capture plants. A summary and the main conclusions from this review are presented in Chapter 11.

2 Potential detrimental effects of flexible operation

There are different approaches that are available to minimise harmful or performance-degrading influences of frequent plant start-ups and fast load swings, but first, this chapter outlines how adverse impacts on equipment can arise. The major process areas of a pulverised coal-fired power generation unit are indicated in Figure 2. Of particular concern in looking at the detrimental effects of flexible operation are the high temperature and high pressure components of plants, but virtually all areas can be affected: plant cycling (on/off and variable output operation) has the potential to impinge on virtually every area. Other parts of the plant that are likely to be affected in various ways, mainly in reduced efficiency, are the auxiliary systems and emissions control systems. Where scope for modifications to better accommodate cyclic operation is limited, as in older plants designed for base load operation, the use of improved monitoring and prediction systems to enable accurate assessments of component lifetimes will become of increasing importance (*see, for example,* Kranz, 2013; Payten, 2012).

Areas with the greatest potential for adverse effects are the boiler and steam turbine systems. When the plant is called upon to operate frequently at rapidly variable output and with frequent shut-downs and start-ups, resultant changes in temperature and pressure give rise to increased stresses on their various components. The consequences are reduced life, reduced performance and increased costs. Nicol (2014) has produced an IEA Clean Coal Centre report recently on the steels used in coal-fired plants, summarising their development, compositions, assessment and performance.

Formerly, when most plants operated on base load, the principal, though not exclusive, mechanism for materials damage to the hot pressure parts was creep, but a combination of creep with other failure mechanisms is to be increasingly expected with rapidly cycling plants (Kranz, 2013). Fatigue is a major contributor, but other harmful processes will add to this.

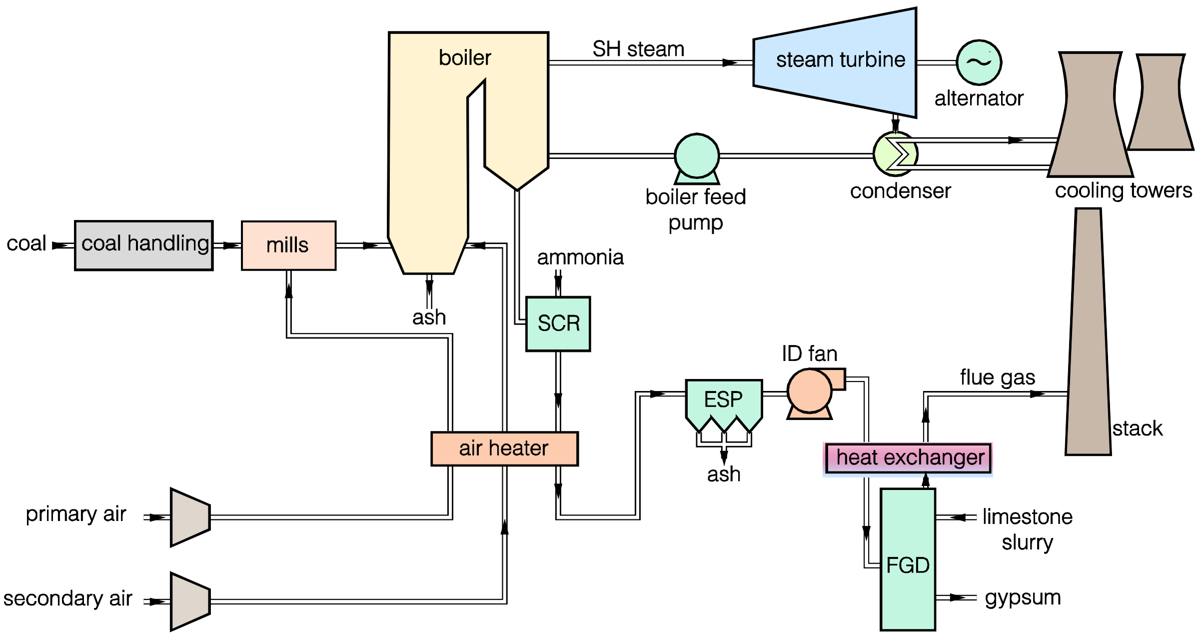

Figure 2 Major process areas of a pulverised coal-fired power plant

The main source of progressive deterioration that occurs when a material is subjected in the laboratory to on/off cycles or variations in loading is fatigue. In power plants, fatigue effects can be enhanced by their occurring in combination with other deterioration mechanisms, particularly creep and corrosion.

Fatigue occurs through the growth of existing flaws or incipient cracks in a material when the stress is applied cyclically. Eventually, if cracks reach a critical size, failure occurs. The number of applications of a given degree of cyclic stress to which a component can be subjected before failure is known as the fatigue life of the component. This is influenced by a variety of factors. Examples are the nature of the material from which it is composed, the temperature, the chemical environment, and the thickness of the component (which can affect temperature gradients). Fatigue is often classified as either high-cycle fatigue, where the number of cycles to failure is large, or low-cycle fatigue, where the number of cycles to failure is small. High-cycle fatigue is characterised by low amplitude, high frequency, elastic (that is, recoverable) strains, whereas low-cycle fatigue is characterised by high amplitude, low frequency, plastic (that is, non-recoverable) strains (DeLuca, no date).

Materials are tested for fatigue life using standard samples that are subjected to cyclic stresses of different amplitudes until they fail. Each test is carried out at a different stress amplitude, and the number of stress cycles to failure is recorded. Cyclic loading is represented in Figure 3, where σ_a is the stress amplitude, and the maximum (σ_{max}), minimum (σ_{min}) and mean (σ_m) stresses are shown.

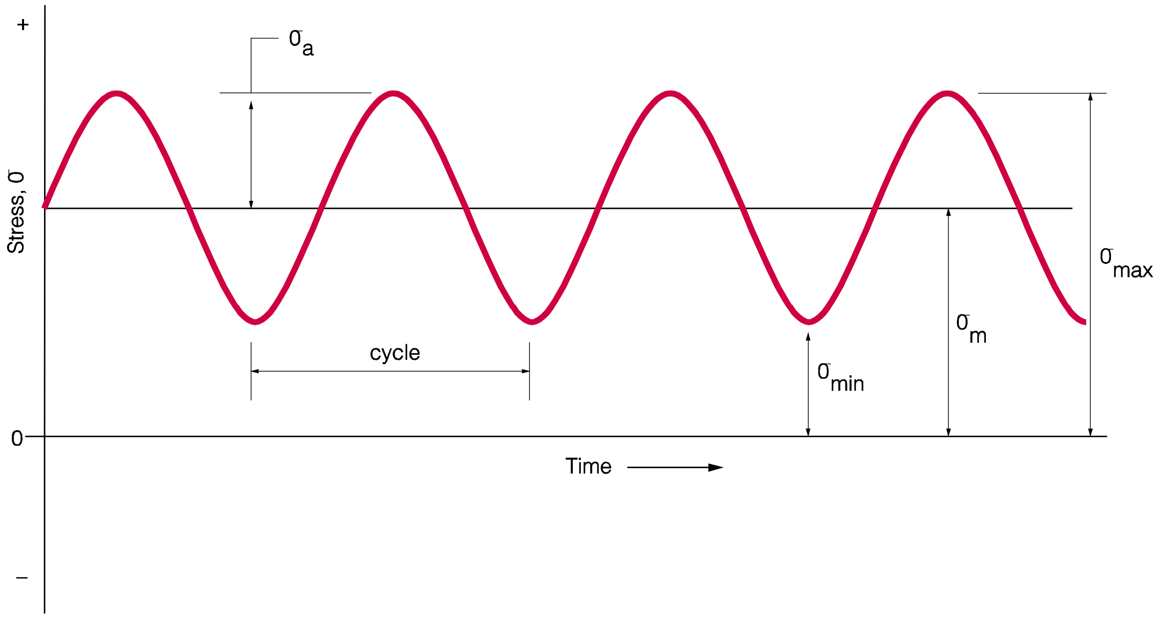

Figure 3 Stress life cycle (Danneman and Lefton, 2009)

From the test data, a graph of stress, S (which has the units of pressure), against the number of cycles to failure, N, known as an S-N curve, is then plotted. Figure 4 shows two examples. As would be expected intuitively, the greater the amplitude of the stress cycle, the shorter will be the life of the test sample. Because materials do not recover when the stress cycle is interrupted (the small cracks will not disappear), the damage to a component constructed from the material is cumulative. For a metal that has been welded or suffered corrosion or creep damage, the curve shows considerable scatter (Danneman and Lefton, 2009).

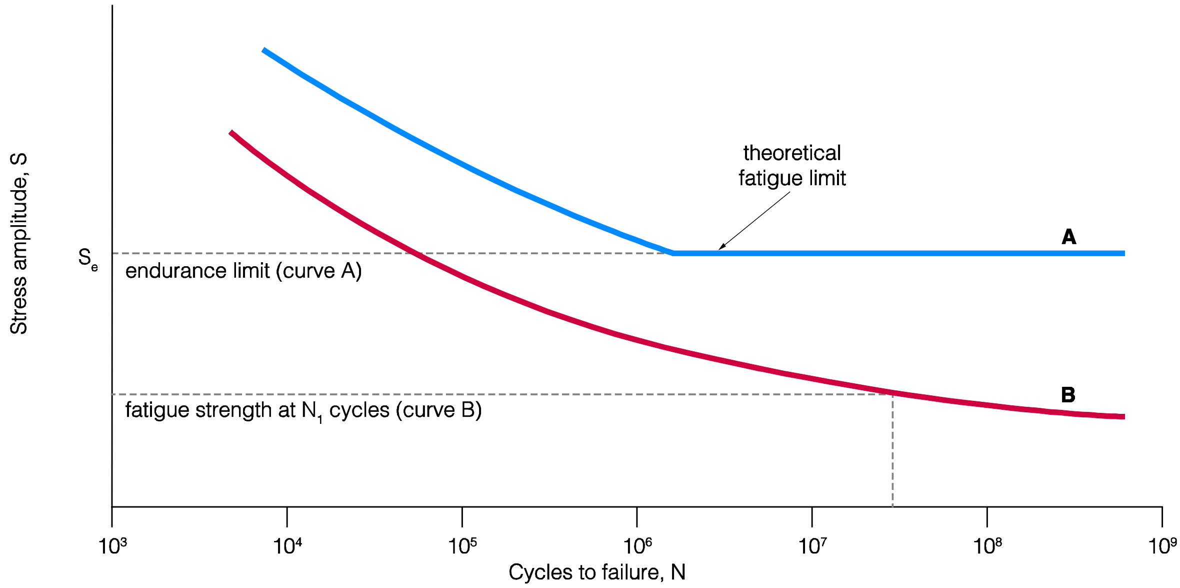

Figure 4 **Typical S-N curve of stress amplitude versus number of cycles to failure for two materials** (Danneman and Lefton, 2009)

There can be a magnitude of stress below which fatigue failure will not occur, regardless of the number of cycles. This is known as the endurance limit, or fatigue limit, and is shown on Figure 4 for material A. An endurance limit does not apply for certain materials, such as aluminium, which will fail eventually at any level of stress cycling. Steels do have a fatigue limit, but there is unfortunately no theoretical lower limit for *corrosion fatigue*, a damage mechanism that has been described as the dominant mode of failure for coal-fired power generation units operating in on/off cycling mode (Danneman and Lefton, 2009).

For thermal cycling fatigue, the number of cycles to failure (N) is related to the range of the temperature cycle (ΔT) thus:

$$N = C/(\Delta T)^{\gamma}.$$

C and γ are constants, characteristic of the material.

In a plant that has been cycling for a number of years, the residual fatigue-related life of the equipment is adequately calculated by taking into account the effects of all the different types of stress encountered. However, for a metal that has been welded, or suffered corrosion or creep damage, the S-N curve exhibits scatter, so predicted fatigue life is subject to more uncertainty (Danneman and Lefton, 2009).

2.1.1 Resultant effects of fatigue on pressure components

The most important areas of likely life-limiting deterioration from fatigue through cycling are the boiler pressure parts and the turbine and its associated equipment. Figure 5 (from Aptech Engineering Services) shows the different types of load cycles that a unit can suffer and, qualitatively, the relative levels of damage that can occur.

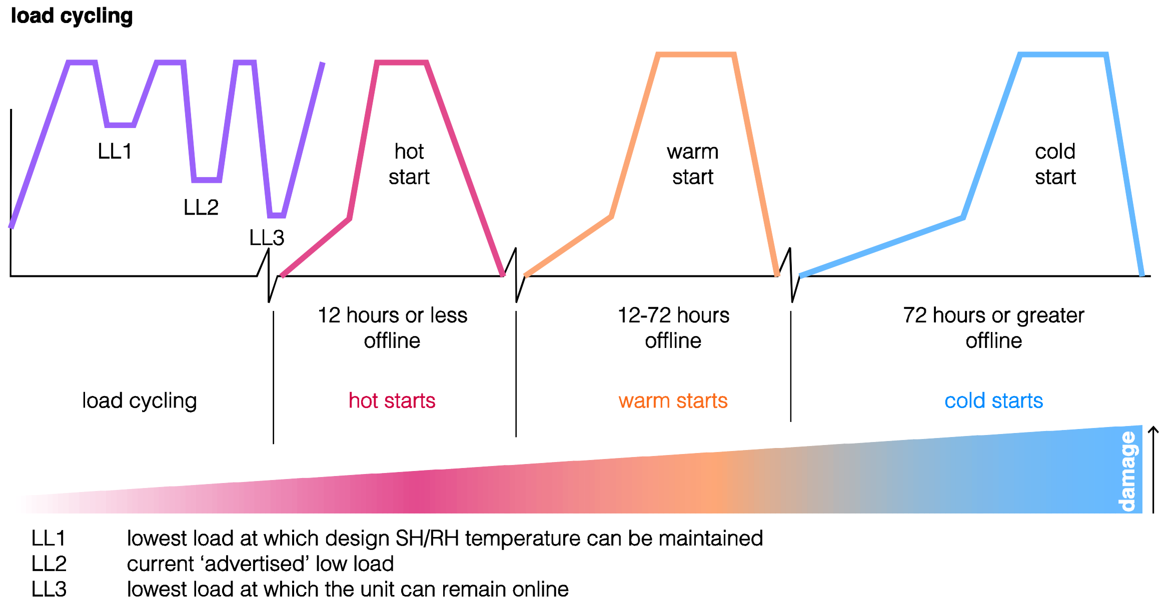

Figure 5 Types of load cycles that a unit can experience and potential relative damage levels (Danneman and Lefton, 2009)

Danneman and Lefton (2009) show that common fatigue-related failures from cycling of existing units in the USA include boiler tube corrosion fatigue, superheater and reheater tube attachment fatigue, turbine blade coating cracking extending into the base metal, and water wall tube membrane cracking. Thermal fatigue, from temperature changes, causes cracks between tube stubs of superheater and reheater headers, as well as damage to turbine rotors and thick-walled castings such as turbine valves and casings (Hesler, 2011).

2.2 Other damage mechanisms and effects of plant cycling

Thermal expansion can itself cause systems to expand so much compared with surrounding components that damage may occur. Examples are membrane wall sections, ductwork, and ties used to support superheat and reheat tubing. Differential expansion also contributes to tube-to-header cracking in superheaters and reheaters (Hesler, 2011).

Low load operation can reduce the flue gas exit temperature from the economiser. This can exacerbate air heater cold-end corrosion, leading to greater cross-leakage within the heater and so lower efficiency (Koza and others, 2011). The low flue gas temperature can also cause problems with maintaining correct conditions in selective catalytic reduction (SCR) systems. The latter is discussed in Section 5.1.

Maintaining boiler feedwater quality is always important, but operating a plant in a cycling mode necessitates additional vigilance. Steps that can be taken when designing or modifying a plant for cycling operation to avoid water quality induced problems include maintaining the correct chemical treatment programme, implementing condensate polishing, and installing on-line monitoring equipment (Koza and others, 2011).

An example of an operational problem that can arise in steam turbines at reduced load is ventilation. As the steam flow is reduced, a disturbance in the flow spreads upstream from the later stages of the turbine. In this mode, only the front turbine stages set performance, while the rear stages give off power to the fluid. In extreme cases, damage can result, but it is mainly a performance issue (Kwitschinski and others, 2013).

A survey by EPRI found that equipment modifications and changes to operational practice could reduce start-up times significantly. Examples were fitting natural-circulation boilers with circulating systems to pump water around the evaporator when off-load and addition of inter-stage drains to prevent condensate from earlier superheater stages reaching hot final stages (Hesler, 2011).

Mills (2011) has included a useful summary table of impacts of plant cycling, sourced from MMU (2010).

2.3 Summary

Normal power plant operation over time results in creep damage to high temperature and pressure components, but flexible operation introduces thermal and mechanical fatigue stresses also. These, together with corrosion, differential expansion, and other effects, often with synergisms, result in a reduction of the expected life of the pressure parts. The residual fatigue-related life of the equipment can be calculated approximately by taking into account the effects of the different types of stress encountered. Many other parts of plants can be affected by plant cycling in the form of either reduction in life, performance or energy efficiency. These include auxiliary systems and emissions control systems. Means to counter these difficulties have been, and are continuing to be, developed.

3 Increasing flexibility – boiler area

In Germany, where the power grid is already experiencing large variations in generation from the extensive capacity of renewable sources, an action plan for increased flexibility in the nation's coal-fired plants has been developed by the Association of Plant Engineering for Energy, Environment and Process Industry (FDBR, 2013). Among the technical suggestions are a large number concerned with the boiler-related parts of plants. These include, in respect of combustion, combustion system optimisation, retrofitting of replacement start-up and flame support burners that use solid fuels (dry lignite, pulverised coal, waste fuels) instead of expensive oil, and installation of indirect firing systems. These methods are discussed in Section 3.1. Some also target minimising emissions and maximising efficiency during changes in output. Other measures in the action plan concern the pressure parts of the boiler and water/steam and turbine systems. These are covered in Section 3.2 and Chapter 4.

Goerner (2012) has highlighted the following additional considerations in designing for high flexibility:

- extension of the acceptable fuel range;
- improved co-ordination of mill and burner systems;
- reduction of combustion chamber volume and height to facilitate fast-load change and high-efficiency at full and partial loads.

Means for reducing the minimum technical load and for increasing the permissible rate of load change are also needed in designing new plants. This additionally involves extending the primary control range (over which the design superheated and reheated steam parameters are maintained) and stretching the secondary control range down toward the revised, lower technical load – *see* Figure 6, from Vattenfall (Dirschauer, 2012).

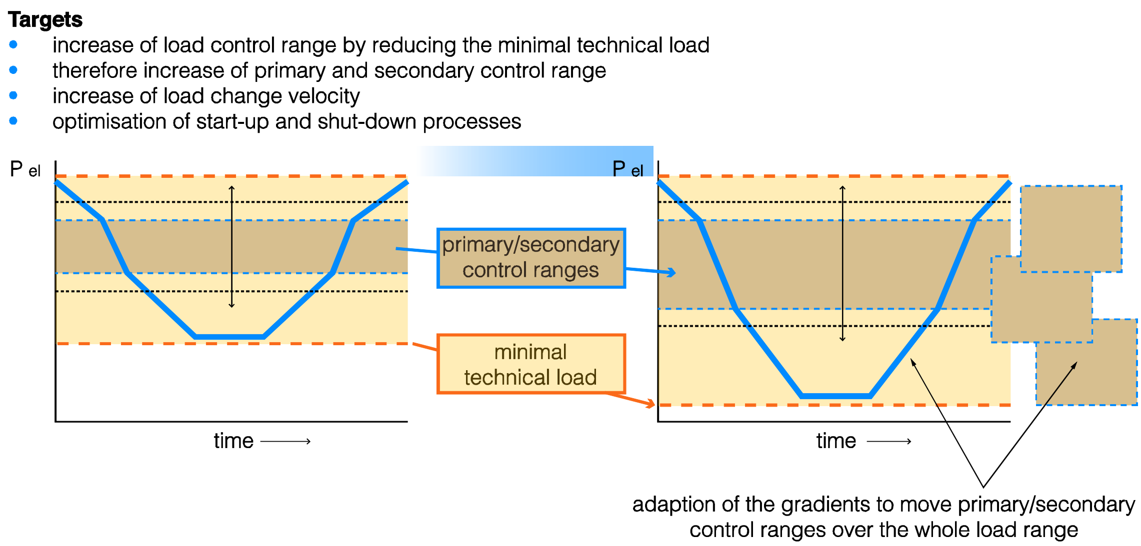

Figure 6 Increasing load range and ramp rate (Dirschauer, 2012)

A critical constraint during rapid ramping is matching steam and turbine metal temperatures. Modern supercritical units provided with sliding pressure operation have advantages in this respect over throttle control during start-up by establishing a flow to the turbine earlier in the sequence, with lower overall heat input and by retaining high temperatures on shut-down (Hesler, 2011; Lindsay and Dragoon, 2010). Sliding pressure is discussed in Section 4.2.

3.1 Firing systems

Among the various areas to consider in increasing boiler flexibility are changes that can be made to the firing systems. The following sections describe some of the means that can be applied.

3.1.1 Varying number of mills in operation to permit lower loads and greater load range

Providing the capability of very low-load running will minimise the number of cold start-up operations. The combustion system needs to play its part. Conventional firing systems for hard coals have permitted typically 40% boiler load without the need for back-up firing. That is far from the sort of performance that will be needed in future. However, it is possible through changes to mill size and burner operating range to achieve 25% load with two out of four mills operating (*see* Figure 7). Where four mills are supplying tangential corner-fired systems, the minimum load can be further reduced: in recent plants it has been shown that single-mill operation can be realised stably, with turndown to less than 20%, reducing the number of shut-down operations (Brüggemann and Marling, 2012). Provision for turndown to 15% has been provided in this way at Heilbronn Unit 7 (Starkloff and others, 2013).

These examples are from Alstom, but other suppliers also offer suitable burners and single-mill operation for very low load capability (*see, for example,* MHPS, 2014a, 2014b). Better instrumentation, combined with sophisticated control, will also improve minimum load capability (Schröck and Dürr, 2013).

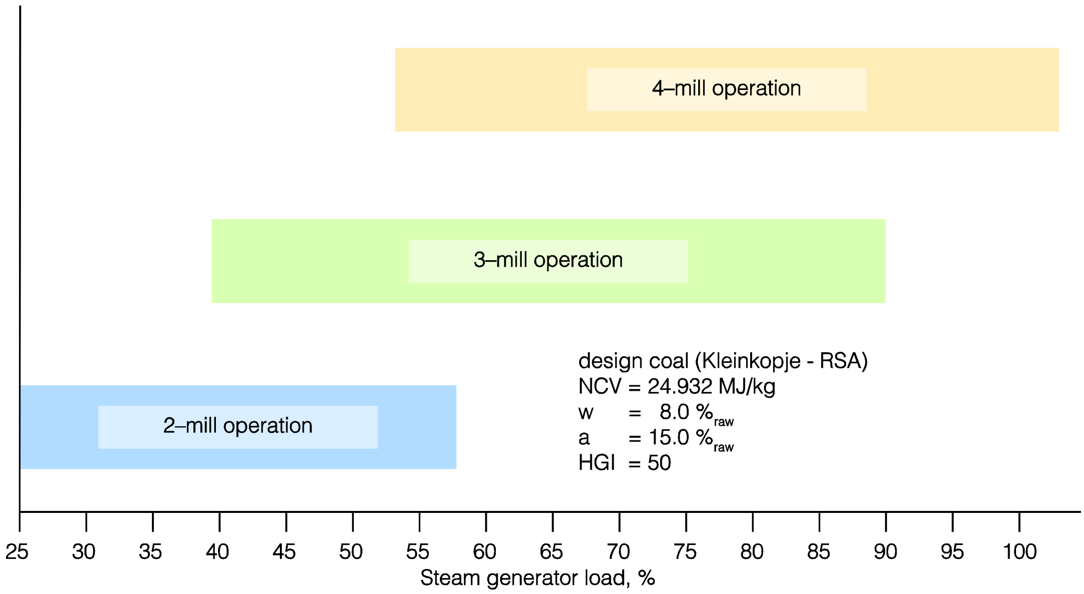

Figure 7 Burner operating range – design with four mills for hard coal (Brüggemann and Marling, 2012)

The use of tilting burners for corner firing gives flexibility in the position of the fireball relative to the heat transfer systems. Higher efficiencies at partial load are realised by reducing the need for reheat attemperation. Efficiency can be increased by 0.5–1% points. Figure 8 shows how adjustments to the reheat temperature can be made without attemperation.

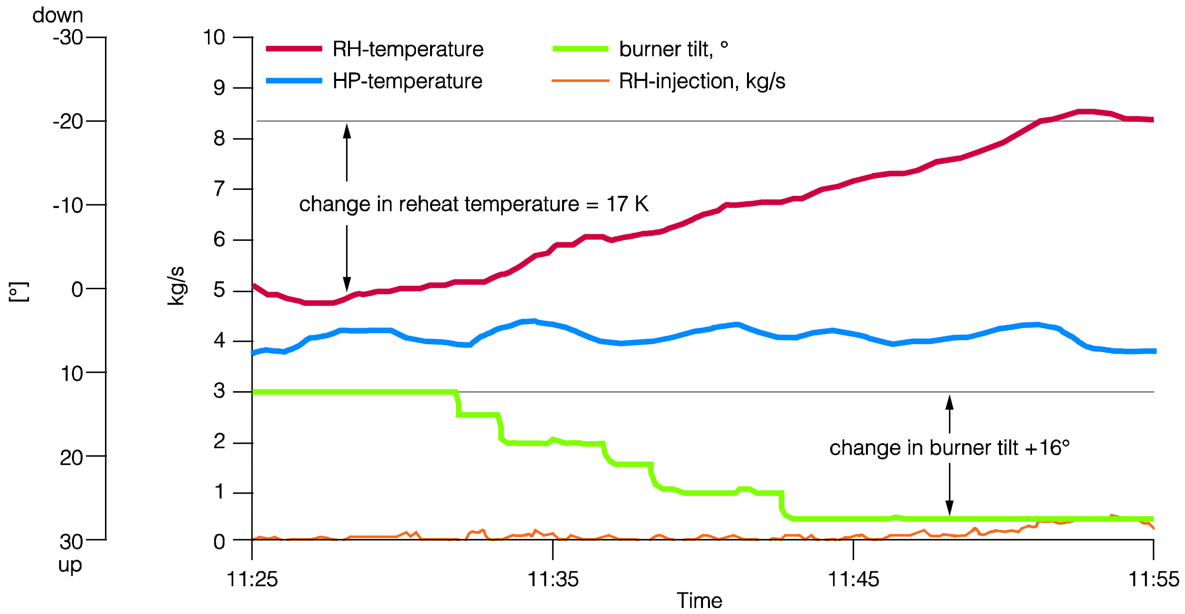

Figure 8 Use of tilting burners to avoid need for reheat attemperation at partial load (Brüggemann and Marling, 2012)

For lignite plants, which may typically have 6–7 beater mills operating at full output, systems are usually designed for a minimum load of 40% for new units (but only down to 50%, for older units), using burner air management and adjustments to the mills and firing systems. Four mills are normally in operation at the 40% load. However, it is possible to achieve a further reduction in minimum output by having only 3 mills in service with fine control of air supply and mill speed adjustments (to ensure flame stability). For example, tests at Vattenfall's lignite-fired Schwarze Pumpe supercritical power plant have indicated that a boiler minimum load of 37% is obtainable (Brüggemann and Schmidt, 2013). This was while the supercritical boiler was still in once-through mode – some water recirculation would also be needed for still lower loads. Reaching a minimum load as low as 35% in both new and existing units is considered possible using these means (Brüggemann and Marling, 2012; Reischke, 2012). Use of lignite after-burners will also reduce the minimum load, give improved stability and extend the permissible fuel range (Reischke, 2012).

Installation of indirect firing systems for hard coals, as well as introduction of lignite drying systems for new designs of lignite boilers, will also enable reductions in the achievable minimum firing and load change rates (Chen and others, 2012; Höhne and others, 2013; Jentsch and others, 2013). These are described in Section 3.1.3.

3.1.2 Increasing the acceptable fuel range with low load operation

Biomass is gaining in application as a cofiring fuel to reduce net CO_2 emissions. Single-mill operation for low load operation is compatible with 10% (thermal) biomass cofiring for large USC units (Brüggemann and Marling, 2012). Start-up can be optimised by putting mills into operation at an early stage, first at part-load, taking advantage of the measures described in Section 3.1.1. Further savings can be achieved with supplementary burners in the primary air system, to provide additional drying energy and allow mills to be loaded faster. Up to 90% of costly support fuel can be saved by switching very rapidly to minimum stable coal/biomass load during start-up (MHPS, 2014a).

For recent information on the influence of biomass cofiring on the design and operation of coal power plants, *see* a number of reports by the IEA Clean Coal Centre (Fernando, 2009, 2012; Dong, 2012; Barnes, 2012; Sloss, 2010).

In order to burn coals of higher moisture contents and lower caloric values than the design coal range for a plant, it is necessary to provide mills with increased drying capacity. In retrofit situations, this can take the form of larger mills with dynamic classifiers, new primary air fans with greater capacity, and means for additional heating of the primary air.

3.1.3 Installation of indirect firing systems

Indirect firing is a system that has been retrofitted successfully to pulverised coal-fired units in Germany to achieve reduced minimum boiler load, and so extend the operating load range. It can also enable increased ramp rates and better part load efficiency. Indirect firing involves installation of a pulverised coal hopper between the mill and burner, together with additional pipework and valves. By using such an arrangement, the instantaneous firing rate is not determined by the mill output at the time (*see* Figure 9). This separation of milling rate and burner feed rate results in a considerable reduction in the inertia of the firing system. The arrangement can allow a rate of change of firing of up to 10%/min (compared with conventional firing load ramps of 2–5%/min). Indirect firing can also stabilise the combustion process, avoid the need for oil as start-up fuel and enable more power to be usefully diverted to coal grinding when there is less demand for power to be sent out. When installed in conjunction with flexible burners, indirect firing can allow the minimum firing rate to be lowered to below 10% of MCR. Efficiency is also improved at low load as mills can continue to operate in their range of optimum power consumption (Reischke, 2012; FDBR, 2013; MHPS, 2014a,b; Busekrus, 2012).

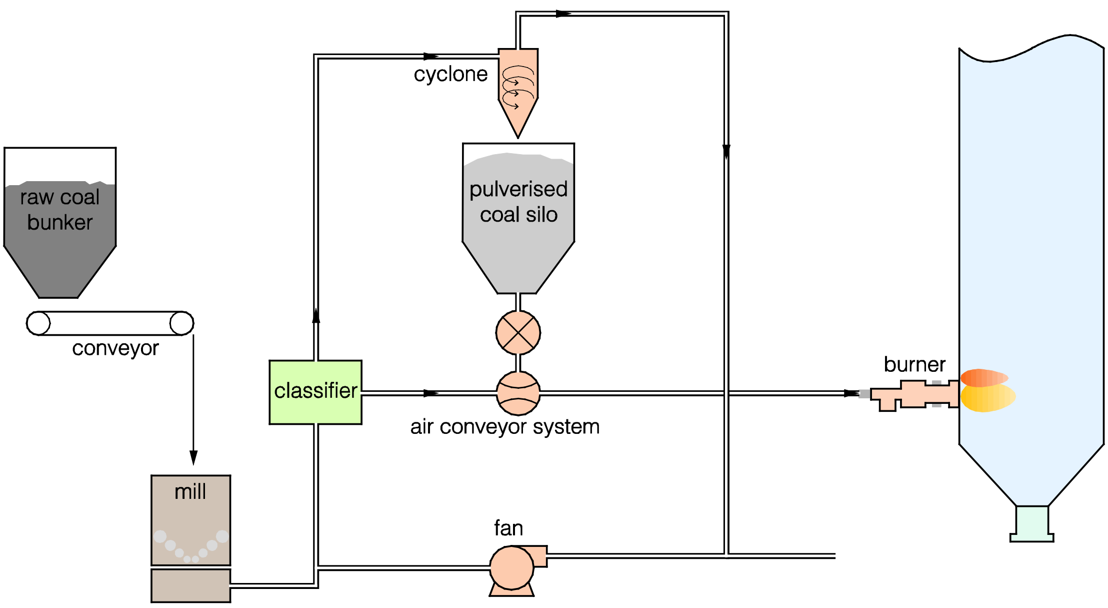

Figure 9 Indirect firing of pulverised coal (Busekrus, 2012)

There can be other benefits of indirect firing also (*see* Table 3).

Table 3 Beneficial effects of installing indirect firing (Busekrus, 2012)

	Direct firing	Indirect firing
Minimum load	25–30%	<10%
Ignition fuel demand	100%	5%
Excess air	15%	<12%
Grinding process	Mills operating at partial load	Mills operating at optimal load

Without installing an indirect firing system with its associated additional valves, pipework and hoppers, it is possible to a more limited extent to improve dynamic performance by simply controlling the coal flow in a conventional configuration that uses vertical spindle coal mills. By varying, within the acceptable range, the grinding pressure of such mills, pulverised coal output can be increased for periods of some minutes by increasing the grinding force. Because the coal feed to the mills cannot be accelerated as quickly, the mills act as energy storage devices (Lindsay and Dragoon, 2010).

Use of lignite pre-drying, while primarily intended to allow higher efficiency, would also provide a method for achieving indirect firing as the dried fuel would be fed to hoppers before firing. This system therefore also provides a capability for increased load change rates and reduced minimum load, as well as a fuel for start-up and combustion stabilisation without the need for fuel oil (Chen and others, 2012; Henderson, 2013; Höhne and others, 2013; Jentsch and others, 2013). The tangential firing arrangement would use corner mounting of the burners for better stability (wall-mounting is used in conventional lignite tangential-fired boilers), and so be akin to hard coal-burning tangential firing systems (Chen and others, 2012). A minimum load of around 30% is suggested by Pinkert and others (2013).

3.1.4 Monitoring and optimisation of combustion

Closer monitoring of the conditions in the furnace is especially important for a unit operating in cyclic mode and when very low loads need to be reached, perhaps with biomass addition. This can allow combustion efficiency to be maximised throughout. An example of the systems available is Zolo's ZoloBOSS technology, based on Tunable Diode Laser Absorption Spectroscopy (TDLAS). This passes laser beams through the furnace between a number of points and spectroscopically analyses the emerging light to monitor the concentrations of H_2O, CO, O_2, CO_2 and the temperature. One of the benefits from such monitoring is the fast response time and reduced need to derive large numbers of correlations (Dubert, 2013; Starke and Williams, 2013).

3.2 Pressure parts

3.2.1 Designing for faster load changes

Tubing and other pressure parts will better withstand the rapid and large changes in temperature associated with on/off and highly variable operation if the thermal gradients are reduced. For this, metal thicknesses need to be made thinner. The number of headers can also be increased. External steam heating or hot storage systems have also been used in Germany to reduce boiler start-up times, while, at Waigaoqiao No 3 in Shanghai, China, an identical adjacent unit can be used for steam heating to speed up start-up of a 1000 MW USC boiler (Henderson, 2013).

More advanced alloys have been developed to enable the metal thicknesses to be reduced, so that the stresses can be reduced in new plants. Former thick-sectioned components made using less advanced steels could only allow output to be adjusted up or down by up to about 3–4%/min. There are differing rates given by various sources, as mentioned earlier, but the highest load rate changes currently suggested by suppliers are as large as 10%/min (FDBR, 2013; MHPS, 2014a,b; Goerner, 2012).

Because the dominant failure mechanism of rapidly cycling units becomes not the development of creep voids, but rather a creep-fatigue interaction, the traditional basis of 200,000 h creep-based design standards is becoming increasingly regarded by plant designers as less applicable. A design life based on 100,000 h, or even less, rather than 200,000 h, without loss of actual plant life for cycling duty, becomes more appropriate due to the lower specific creep strain (Kranz, 2013; Reischke, 2012; Wolff, 2012). Figure 10, from Reischke (2012), shows how the creep lifetime consumption per cycle is significantly reduced by designing components for 100,000 h instead of 200,000 h at full load. Hence, more rapid cycles are possible.

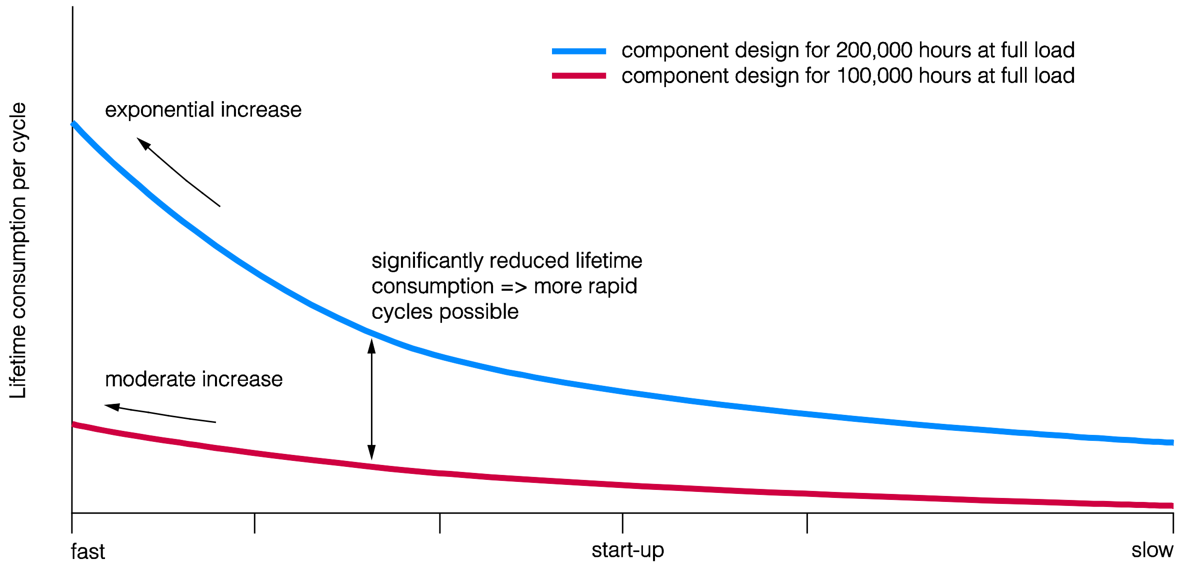

Figure 10 Comparison of lifetime consumption of superheater headers for design creep life of: a) 100,000 h; b) 200,000 h (Reischke, 2012)

Modern calculation methods, such as the Finite Elements Method (FEM) of the European Pressure Equipment Directive (PED), more closely simulate the real gradients in complex structures and facilitate the calculation of the (smaller) design wall thicknesses (Busekrus, 2012; Kranz, 2013). The dimensions and permissible temperature increase rates compatible with acceptable creep rates for a P92 header are shown in Table 4.

Table 4 Dimensions and creep performance of a P92 header (Busekrus, 2012)

Internal diameter, mm	Pressure rating, MPa	Temperature rating, °C	Required thickness according to EN12952-3, for 2.9 K/min gradient, mm	Required thickness, based on modern calculation methods, for 5.1 K/min, mm
255	29.5	615	100	77

3.2.2 Reducing the minimum load

Reducing a boiler's minimum load capability can be achieved through various approaches, for example, for new boilers, by paying special attention to evaporator design and, in existing systems, carrying out economiser modifications. Conditions in the economiser have to be correct, that is, such that there is an adequate degree of sub-cooling of the feedwater to prevent steaming. A reduction in minimum load has been found generally to be possible for existing boilers following assessment (Hamel and Nachtigall, 2012, 2013). The first step is to determine the current minimum technical load, based on thermal input, steam temperatures, flue gas temperatures and stability. This is followed by a feasibility study, involving modelling of the various boiler components, to permit a comparison of potential options. A detailed engineering study of the preferred option is then carried out to confirm costs before implementation.

An example from a case study referred to by Hamel and Nachtigall (2012, 2013) is the adjustment of a steam generator's flue gas temperature after the economiser to achieve the design value at loads down to

30% without economiser steaming. This was done by adding an economiser water-side bypass together with feedwater recirculation pumps and pipework. The same authors show, in another example, the approach adopted to achieve low (20%) load operation through the static and dynamic stabilisation of a spiral wound evaporator of a boiler (Hamel and Nachtigall, 2012, 2013). This included the following elements:

- creation of a thermal model of the boiler;
- analysis of operating data for full and partial load situations;
- calculations of the static and dynamic stability of the spiral evaporator;
- calculations of the static stability for all downstream heating surfaces;
- determination of the stable minimum load in the absence of modifications;
- comparative investigations of the potential advantages and limitations of different stabilisation concepts.

One way of designing for minimum load in designing new boilers is to use internally rifled or ribbed tubing within the evaporator (Reischke, 2012). This enables higher heat transfer rates at lower water flows. Circulating pumps may also be retrofitted to once-through boilers to reduce losses from steam escaping at low loads and during start-up (Schröck and Dürr, 2013). In drum boilers, it may be possible to increase the flow rates in the evaporator to achieve greater stability (FDBR, 2013).

3.3 Plant configuration choices

3.3.1 Using more than one boiler

Configuring a new plant to have more than one boiler supplying the steam to a single turbine will allow a greater degree of flexibility. RWE are developing a plant concept using 2 x 550 MW boilers connected to a single 1100 MW steam turbine for a possible future lignite plant in Germany. This would give high flexibility, with load change rates similar to those of modern gas-fired power plants. A turndown from 1,100 MW to around 175 MW would be possible (Wolff, 2012; Reischke, 2012).

3.3.2 Integrating gas turbines

In Germany, retrofitting of gas turbines equivalent to about 20% of the existing power plant capacity has been carried out at some plants, to enable output, efficiency and load change rate to be increased. They may be added either to create what is fairly similar to a conventional combined cycle or else to provide feedwater heating in a less integrated, lower efficiency, combination (MHPS, 2014b; Gurner, 2012; FDBR, 2013). The energy efficiency of usage of the additional natural gas can reach approximately 80% in some systems, compared with about 60% for a modern dedicated natural gas-fired combined cycle power plant (FDBR, 2013).

4 Increasing flexibility – turbine and water-steam systems

There is much that can be done to make these areas of a plant more durable, able to respond faster and suffer less efficiency losses. Examples are given in this chapter.

4.1 Reducing stresses during start-up

Start-up, especially from cold, places particularly large stresses on many parts of a coal-fired plant. The turbine is no exception in this regard. Very rapid temperature changes need to be kept to the minimum, while component designs can be adapted to suit. Lindsay and Dragoon (2010) have collected together data from published sources on start-up times for different plant conditions. They found that, generally, coal plants required approximately 12 hours to cold start, 4 hours to warm start, and 1 hour to hot start. There was considerable variation, and this was believed to stem from how hot, warm, and cold starts were defined, and whether those times were actually equipment-limited or not.

One of the requirements for flexibility in the turbine is that the very small clearances between stationary and moving components remain almost constant during output changes. This requires careful design, advanced sealing (*see also* Henderson, 2013) and measures for ensuring uniform thermal loading and applies especially during cold start-up operations (Quinkertz and others, 2008).

Turbine bypass systems are a necessity in plants designed for two-shift (on/off) and other flexible forms of operation. They allow all or part of the steam to bypass the HP turbine or LP turbine so that the rate of steam temperature change in the turbine can be managed as the boiler is starting up and shutting down. This allows thermal stresses in the turbine to be reduced (Lindsay and Dragoon, 2010). This is not to be confused with another type of bypass (HP stage bypass), that can be installed for frequency control in new plants and is described later.

The very high temperature and pressure conditions of USC systems necessitate use of thick-walled components so that they possess adequate strength. Unfortunately, this can limit the rate of temperature change consistent with reducing thermal fatigue to acceptable levels. In the turbine, one means used to counter this is steam cooling of the outer casing to keep its temperature 30–40°C lower than that of the inner casing at the corresponding position along the turbine during load changes. The steam for this is bled radially from points along the inner casing. The steam reduces temperature extremes in the outer casing and allows its thickness to be reduced. The result is that cold start-up time is reduced by almost 50% (Almstedt and others, 2007).

4.2 Load following using sliding pressure operation

While, traditionally, throttling has been used to vary output from a turbine while keeping the pressure constant (Lindsay and Dragoon, 2010), sliding pressure operation has become a commonly applied system in modern supercritical once-through systems (Henderson, 2004). A critical constraint on ramping operation is matching steam and turbine metal temperatures, and more rapid output changes can be achieved using sliding pressure. Sliding pressure also offers advantages over throttle control during start-up, by establishing a flow to the turbine earlier in the sequence, with lower overall heat input and by retaining high temperatures on shutdown.

This is a whole-plant design aspect, since it concerns the boiler as well as turbine systems. At the reduced pressure used for part load operation, when the system is operating subcritically, evaporation occurs in the boiler within a region of tubing that shifts with changes in load as the enthalpy increases in the boiler associated with preheating, evaporation and superheating change with pressure. The decrease in efficiency at reduced load is reduced, as better control of turbine temperatures and wetness is possible than when the governor valves are throttled. In addition, boiler feed pump power consumption is reduced and there are lower stresses on components such as valves.

In practice, a certain degree of throttling is usually also used to maintain some reserve steam to give the capability for meeting sudden increases in power demand (*see also* Section 4.4). Sliding pressure has been used for around twenty years in units in Denmark and in Germany, for example at the Rostock unit in Germany (Vitalis and others, 2000). Sliding pressure once-through boilers are provided with small steam drums for water and steam separation at the (subcritical) conditions of reduced load. Small separator vessels and a recirculating pump are in any case normally provided for start-up (Henderson, 2004).

4.3 Other ways to achieve greater load range and ramp rate

Addition of bypass pipework around feedwater heaters is a convenient modification to increase flexibility. The lower resultant temperature of the feedwater at the economiser inlet can then allow lower loads to be reached without economiser steaming (FDBR, 2013). Economiser steaming can be a problem limiting the extent to which water flow, and so plant load, can be turned down (*see also* Section 3.2.2).

Provision of bypasses around high pressure feedwater heaters, accompanied by the (necessary) closing of the HP bleed steam valves, can also be used to produce *additional* power over about 20-30 minutes. This occurs because the steam flow through the turbine is increased (Wechsung and others, 2012; Lindsay and Dragoon, 2010). Feedwater heater bypass used in this way can provide a means of very rapid response suited for frequency control (*see* Section 4.4).

Of relevance in considering new plant designs, separate HP and IP turbines, as opposed to combined HP/IP systems, are said to make faster load changes possible (Cozza, 2012).

4.4 Rapid response for frequency control

Many coal-fired power units already incorporate the means to provide very rapid output changes of 5% or even up to 10% within a time of no more than about 30 seconds (Reischke, 2012). These are plants that are designated and so designed to provide frequency stabilisation on the grid through primary frequency control. In addition to this very short-term response duty, other units are designated to operate to provide secondary (within several minutes) frequency control. The response of the latter frees up the primary frequency control units making them ready to provide immediate response again. Although not actually the same designated duty, providing secondary frequency control has similar implications for plant design to providing the capability for meeting large, rapidly changing supply/demand gaps, covered in other sections of this report, so this section concentrates on means for primary frequency control. Retaining some fossil-fired units for primary and secondary frequency control will remain very important in the future, as many renewable energy generators do not provide frequency control. Coal-fired plants designated for frequency control are kept on, and so synchronised, but operating below full load, ready to provide a response when needed.

Methods available for primary frequency control include the well-established means of opening of throttled main steam valves, but also, nowadays, condensate throttling, feedwater heater bypass (*see* Section 4.3) and HP stage bypass. Another alternative is to install a thermal storage system, which can also increase the load range. The latter is described in Section 4.5.

The three Torrevaldaliga North 660 MW USC units commissioned in Italy between 2009 and 2010 have been designed to provide primary frequency control through turbine throttling. Each 25.3 MPa/604°C/612°C (at boiler outlets) unit has the capability for producing a 4% change in power within 30 seconds. The turbines were supplied by MHI Ltd. The response time of the boilers, supplied by Ansaldo Caldaie S.p.A. and Babcock Hitachi Kure (BHK), is approximately 90 seconds. This allows the primary reserve provided by the turbine system to be recovered quickly, with provision of the power reserve for 15 minutes in accordance with the grid requirements (Penati and others, 2011).

The principle of condensate throttling is that the turbine control system opens the governor valves, if not fully open, to utilise the reserve steam storage capacity of the boiler (as in conventional throttling in absence of condensate throttling). The flow of condensate to the low pressure feedwater heaters is reduced at the same time by throttling the main condensate control valve (*see* Figure 11). The flows of extraction steam to the LP feedwater heaters and the deaerator/storage tank are therefore reduced. These actions leave additional steam flow in the turbine, generating the additional power. The response time can be optimised using additional fast acting valves in the extraction steam lines giving a maximum output after about 30 seconds (Cziesla and others, 2009; Quinkertz and others, 2008). The boiler fuel feed rate is also increased. At Waigaoqiao No 3 plant in Shanghai, China, a similar principle has been used on the Siemens turbine in adjusting condensate flow to vary indirectly the flows of extraction steam to enable transient demands to be met efficiently (Henderson, 2013).

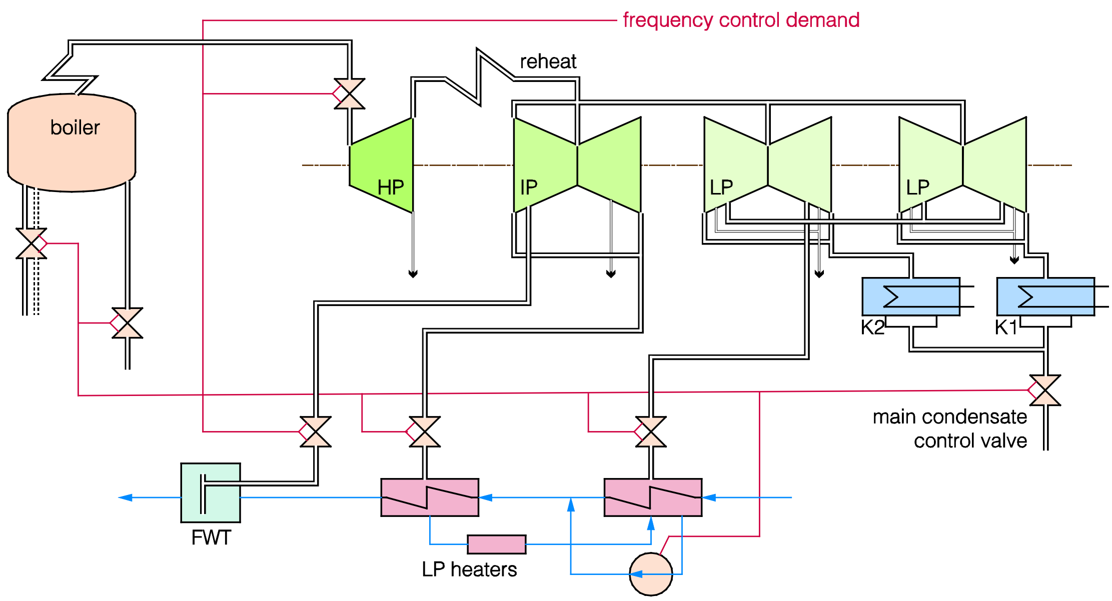

Figure 11 Condensate throttling for rapid response (Cziesla and others, 2009)

Another very rapid response system for primary frequency control that can be supplied with USC steam turbines is HP stage bypass. Figure 12 shows the system in Siemens 600-1200 MW turbines equipped with sliding pressure and full arc admission over the load range. It permits additional HP steam to be admitted to the HP turbine some stages after the first blade row when the bypass valve is opened, also to give full arc admission at that stage. The system is normally designed to give a short-term 5% increase in power. It is however possible to design such systems for an additional 10%, or even, if required, 15% increase in power (Almstedt and others, 2007; Wechsung and others, 2012). Normal operation at 100% MCR is achieved with the stage bypass valve closed. Efficiency falls upon opening it, but providing frequency control is a necessity to stabilise the grid. In any case, the HP stage bypass system is the most efficient means that is available for achieving rapid load increase (1% per second) because throttling losses are at a minimum at both points (Quinkertz and others, 2008). The stage bypass system is available for use within the whole load range. In contrast, throttling is normally operated at around fairly high load. Alstom supply similar systems (Alstom, no date).

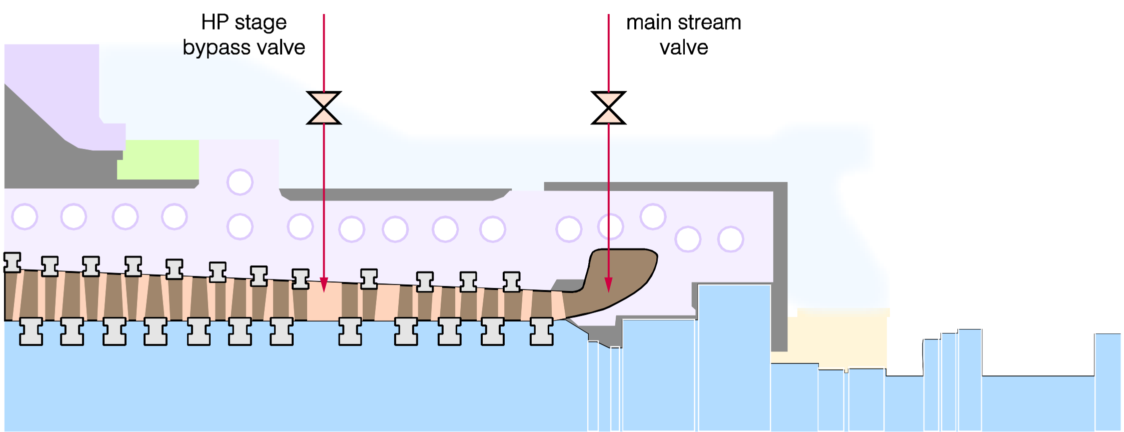

Figure 12 HP stage bypass system for very rapid response (Almstedt and others, 2007)

Alstom show a primary frequency control capability of 10% in 10 seconds as being under development for new and existing plants without expanding on the nature of the system (*see* Table 5) (Reischke, 2012).

Table 5 Flexibility capabilities of coal-fired units (Reischke, 2012)

	State of the art:	**Development (new and existing plants):**
Start-up:	2–6 hours depending on starting condition	1–4 hours depending on starting condition
Minimum load (hard coal)	New power plants: 25% Existing power plants: 40%	Conventional firing 15–20% Indirect firing 10–15%
Minimum load (Brown coal)	New power plants: 40% Existing power plants: 50%	Conventional firing 35–40% Indirect firing 10–15%
Load change cycles	Moderate	High to very high
(Primary frequency control)	2–5%/30 s possible to 5%/30 s	10%/10 s
(Secondary frequency control)	2–/min	10%/min
Biomass	10% cofiring	100% biomass

Modern control strategies have been said to permit a reduction of boiler inertia by more than 30%, reducing the turbine valve throttling needed for frequency control (Rech and others, 2009).

4.5 Thermal storage systems

Bypass of feedwater heaters has already been described as a way to increase steam flow for up to 30 minutes (*see* Section 4.3) and for frequency control, but even more flexibility can be achieved by installing storage systems for the low pressure or high pressure feedwater. An extended load range, increased ramp rate and provision of an alternative means for primary and secondary frequency control result (FDBR, 2013). Figures 13 and 14 show variants of a system that can be installed that is in principle capable of rapidly providing 5% more power at existing plants (Schuele and others, 2012).

The LP feedwater heaters are provided with a bypass which feeds upright cylindrical storage tanks (*see* Figure 13). These tanks contain both the cold and hot condensate, and any increase in storage of hot water displaces cold water and vice-versa. When power output needs to be reduced, the tanks are filled with hot condensate, taken from the outlet stream of the deaerator/feedwater storage tank. To achieve this, the condensate mass flow through the LP preheaters and the feed water tank is increased. This causes increased extraction of steam from the IP and LP turbines, reducing power output.

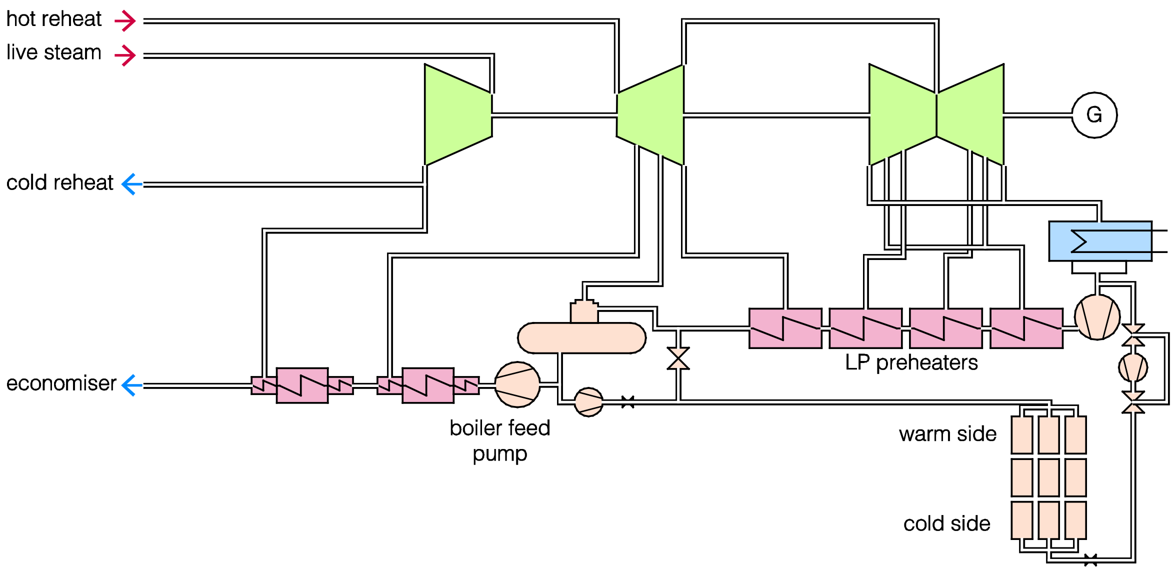

Figure 13 Thermal storage system for increasing plant flexibility (Schuele and others, 2012)

When additional generation is required, the LP feedwater preheaters are bypassed, and the cold condensate from the condenser displaces the hot condensate in the storage tanks. The hot condensate is introduced upstream of the deaerator/feedwater storage tank. Because the LP feedwater heaters are bypassed, they do not draw extraction steam. The hot condensate from the thermal storage tanks is at approximately the same temperature as that of the water in the feedwater tank, so no IP extraction steam is required at this point either. The steam flows through the final stages of the IP turbine and the LP turbine are consequently increased, raising electrical output.

The increase in output is greatest at full load, because then the impact of the reduced extraction steam mass flow is maximised. Approximately 5% of MCR can be produced. The associated capital cost is much lower and the efficiency associated with the system is much greater than for energy storage alternatives such as batteries or compressed air storage. The usable load range is also extended, as there is no need for other means, such as throttling, to provide frequency control (Schuele and others, 2012).

The more involved system in Figure 14, which utilises additional feedwater heaters, enables even greater flexibility. During heat storage, steam from the plant is used to heat the cold condensate from the tanks. In this case, the 'charging' condensate mass flow is independent of the water-steam cycle. The load reduction occurs because of the diversion of IP steam from the turbine. Adding the condensate from the storage preheater to the hot storage condensate reduces the 'charging' time. Power increase is achieved in the same way as for the simpler system, by cold condensate displacing stored hot condensate, which is re-introduced upstream of the feedwater tank.

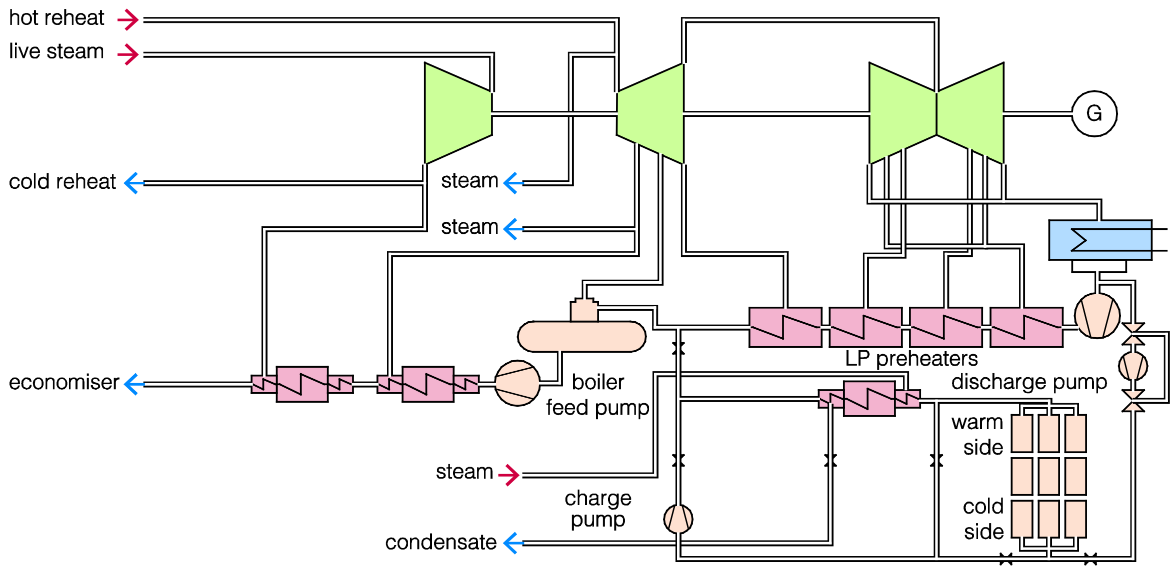

Figure 14 Thermal storage system for increasing plant flexibility (variant) (Schuele and others, 2012)

4.6 Water treatment

Poor water quality causes corrosion, and the likelihood of water quality deterioration is increased as a result of frequent load changes. For once-through boiler systems, all-volatile treatment and oxygenated treatment are used. Boilers operating in a cycling mode are best provided with all-volatile treatment together with full-flow condensate polishing. All-volatile treatment with oxygenating is preferable for ferrous-only based systems. It allows air in-leakage, resulting in dissolved oxygen levels of 1–10 ppb that form a ferric oxide hydrate layer on the magnetite (Nicol, 2014). The dissolved oxygen concentration is controlled by mechanical means, while chemicals such as ammonium hydroxide and hydrazine or other substances can be used as the pH adjuster (Koza and others, 2011). Condensate polishers remove dissolved contaminants, such as sodium and silica, and filter suspended particulates that become detached from heat exchanger internal surfaces during load transitions (Koza and others, 2011).

Operation of makeup water or wastewater clarifiers can be improved by the addition of recirculation lines to allow the maintenance of adequate flow through the clarifier at low load, keeping it ready for increased load operations (Koza and others, 2011).

5 Increasing flexibility – other plant areas

On/off and highly variable load operation affects other parts of the plant also. This chapter describes the potential problems that can arise and how they can be overcome.

5.1 NOx removal systems

The main potential issue with low load operation of plants with selective catalytic reduction (SCR) systems, which are usually placed after the economiser, is the possibility of lower flue gas temperatures occurring. SCR units often use ammonia as reagent, and ammonia control may become difficult during fast load swings, compounded by variable fuel properties. Excess ammonia can then leave with the exit gas stream. This so-called ammonia slip can then lead to ammonium bisulphate (ABS) formation as a sticky liquid that fills catalyst pores, reducing reactivity. ABS may also deposit in the air heater, increasing its pressure drop, and necessitating cleaning. It can even be blown from the air heater into boiler air ducts, where it can influence readings of air flow measurement devices.

To avoid problems with ABS formation, the conventional solution is for a flue gas or water-side economiser bypass to be installed to enable the flue gas temperature at low load to be kept at design value (FDBR, 2013). Such an arrangement can avoid plugging without sacrificing NOx removal performance (Rummenhohl and Davis, 2012; Koza and others, 2011; Moser, 2006). Where units are not, or cannot be, equipped with economiser bypass capabilities, other options are available. One is to monitor continuously the inlet NH_3 and SO_3 concentrations and temperature distribution in the SCR, and to compare these with design conditions. Other possibilities may be to change the fuel sulphur content or, if allowed, the NOx reduction levels at low load, or to modify the inlet temperature distribution using a static mixer (baffle). Adding a heating facility for hot gas carrying components can also be used to give shorter start-up times (FDBR, 2013). Whatever means is used, provided the correct temperature can be maintained, rapid rates of load change can generally be accommodated (Beckmann and Lerke, 2012).

5.2 FGD systems

The chemical processes involved in conventional wet flue gas desulphurisation (FGD) systems require precise control of the reaction conditions, which are influenced by reagent flow, water flow and flue gas temperature. Operation at varying power output can consequently affect the performance and reliability of these plants. The number of shut-downs and start-ups of FGD systems should also be minimised because of the need to purge to avoid slurry solidification. Reducing the number of shut-downs and start-ups is also needed to minimise the accumulation of start-up fuel oil residues on absorber linings, and to avert the lengthy warming up time that is needed by an FGD system.

It can be possible to obtain savings in energy consumption at part load by switching off some circulation pumps. Goerner (2012) suggests updating control systems to reduce the energy demand. However, at low-load, it will be difficult to maintain optimal performance if the reagent flow is fixed. Keeping within required emissions limits during rapid load changes requires sophisticated control concepts, and an increased liquid/gas ratio may be needed for sufficient SO_2 capture (Beckmann and Lerke, 2012).

5.3 Particulate removal systems

Particulate control systems can usually cope with a plant operating at partial load and rapid load changes without problems. Inlet gas temperatures need however to be watched – they must not fall so low that acidic moisture condenses on particles, causing adherence of solids to fabric filters or a resistivity that is too low for efficient ESP performance. At partial (or full) load, enhanced dust collection may be achieved in electrostatic precipitators by increasing residence time, while energy savings of up to 80% are possible using intelligent control systems for the power supply (Beckmann and Lerke, 2012). Goerner (2012) suggests that flexible plants include modern controls for electrostatic precipitators to reduce their energy consumption. A recent IEA Clean Coal Centre report describes developments in various types of particulate removal systems (Nicol, 2013a).

5.4 Auxiliary systems

During start-up and operation at reduced load, a power plant is at off-design conditions. Consequently, the thermal efficiency is reduced. It is desirable in flexible operation that any efficiency penalties be minimised. Apart from reduced boiler and turbine performance, a penalty can come from excessive power consumption by ancillary systems. Auxiliary systems on older plants designed for base load waste power at low load as drives still draw too much power. Examples are the major fans and the feedwater pumps. Flexible drive motors using variable frequency power supplies are now available for these large consumers in the power plant to reduce the energy losses from this source (FDBR, 2013; MHPS, 2014b; Hesler, 2011; Koza and others, 2011, Lindsay and Dragoon, 2010). Variable frequency drives for cooling tower fans can also help regulate condensate water temperature. Other suggested methods suggested by Goerner (2012) for flexible plants include using superconducting components. However, the latter technology is not widely used and is basically still developmental.

Supplying the auxiliary drives with power at varying frequency enables their operating efficiency to be improved when a plant is operating at reduced load, as mentioned above. At Waigaoqiao No 3 power plant in Shanghai, China, a novel means of achieving this has recently been developed and installed. It consists of a variable frequency turbine (manufactured by Siemens) driven by steam extracted from the main turbine. This follows the change of load to change the frequency supplied to the plant auxiliary systems and has been shown to save a considerable amount of power (Feng, 2014).

6 Control systems for improved flexibility

It is generally worthwhile replacing control and instrumentation systems in older plant to increase efficiency and flexibility. RWE has carried out such retrofits on its 300 MW and 600 MW lignite fired units to achieve greatly increased ramp rates and lower minimum loads. Figure 15 shows the demonstrated and predicted future improvements on a 600 MW unit (Eichholz and others, 2013).

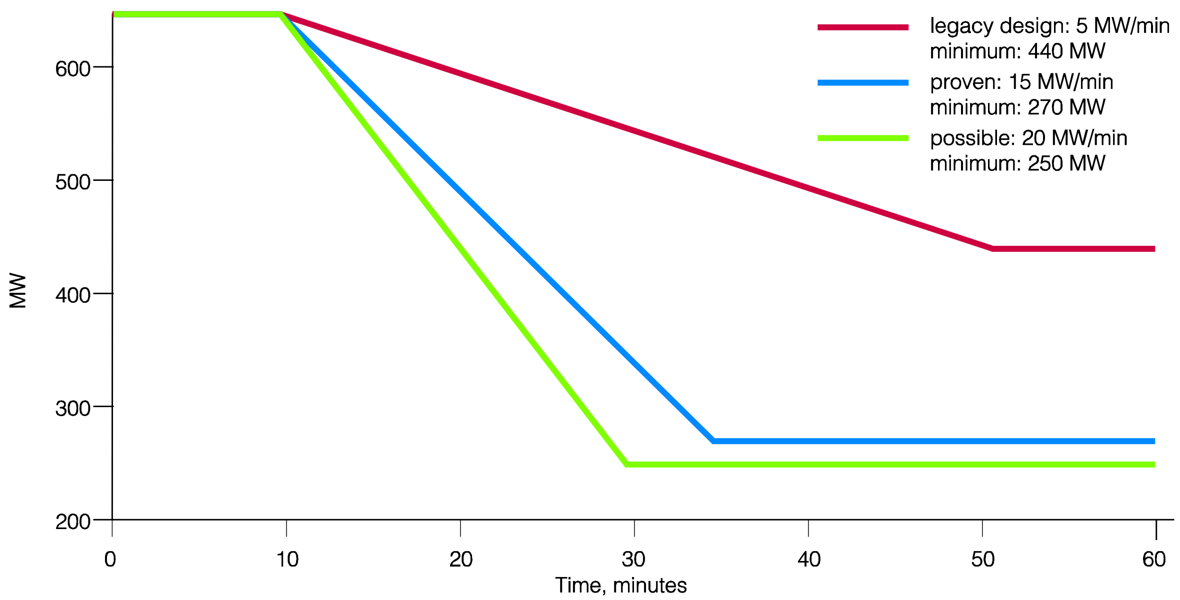

Figure 15 Demonstrated and predicted future improvements in minimum load and ramp rate on 600 MW lignite-fired units from retrofitting modern control systems (Eichholz and others, 2013)

6.1 Boiler control systems

Conventional control schemes are designed to provide responsive control within a unit's normal operating capacities. However, the boiler and steam-side response profiles are significantly affected at low load. Furthermore, conventional control systems may not be able to take into account changes such as those occurring as a plant ages (Wendelberger and others, 2009). Thus, if the dynamic response of the boiler changes over time, control performance will become degraded. In that case, the simple proportional integral derivative (PID) controller has to take corrective actions increasingly frequently. Eventually, the plant's stability and flexibility suffer. Modern systems available now can overcome such difficulties. For example, Siemens Energy has developed a system (advanced process controller – APC) for controlling the main steam pressure by adjusting the fuel flow (Figure 16). This controller is said to reduce commissioning time by more than 50%. The APC is able to stabilise non-stable loops so that it is not necessary to use the steam turbine to help stabilise steam pressure. As a result, the electrical load will follow its set point with a very high degree of accuracy and the APC can act as a full pressure controller, and dynamic tracking of the pressure set point in case of load changes or frequency disturbances is unnecessary (Wendelberger and others, 2009).

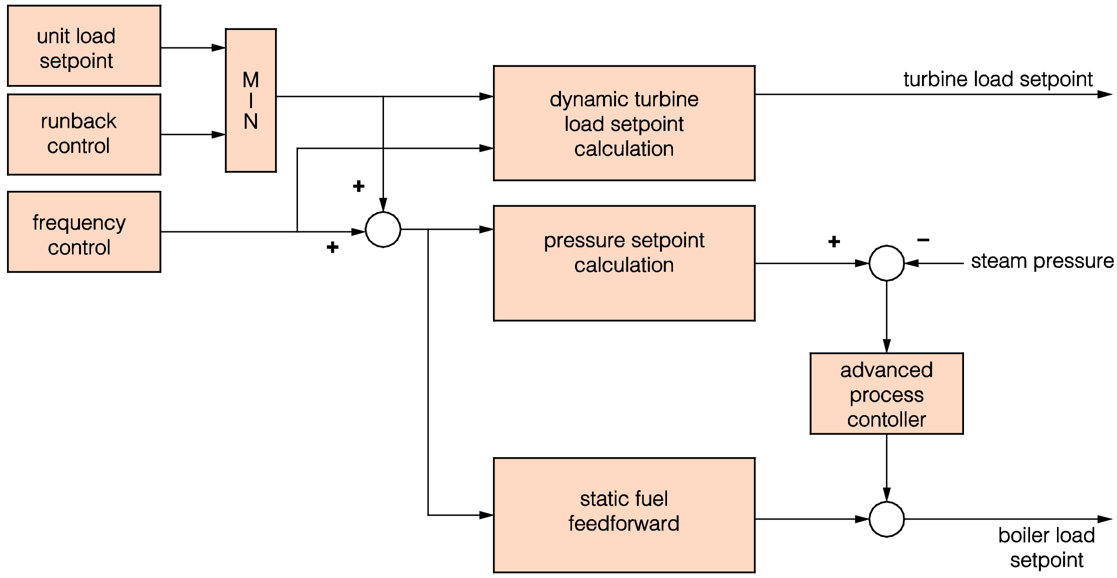

Figure 16 Unit control concept with APC. Source: Siemens AG (Wendelberger and others, 2009)

The authors describe how unit fitted with the APC responded when the load setpoint was increased and then reduced at a load change rate of approximately 5% per minute. The APC was able to stabilise the pressure quickly, and the load followed its set point closely. With the new control structure, control performance levels can be attained that were previously considered to be impossible (Wendelberger and others, 2009). Even further gains can be expected in the future with whole plant controls that use predictive algorithms. These are discussed in Section 6.3.

Schröck and Dürr (2013) describe how modern control systems can enable combining of the operation of multiple units to obtain faster ramp rates (*see* Figure 17) while keeping availability at a maximum. More sophisticated control and instrumentation will also improve minimum load capability, for example, through additional flame monitoring.

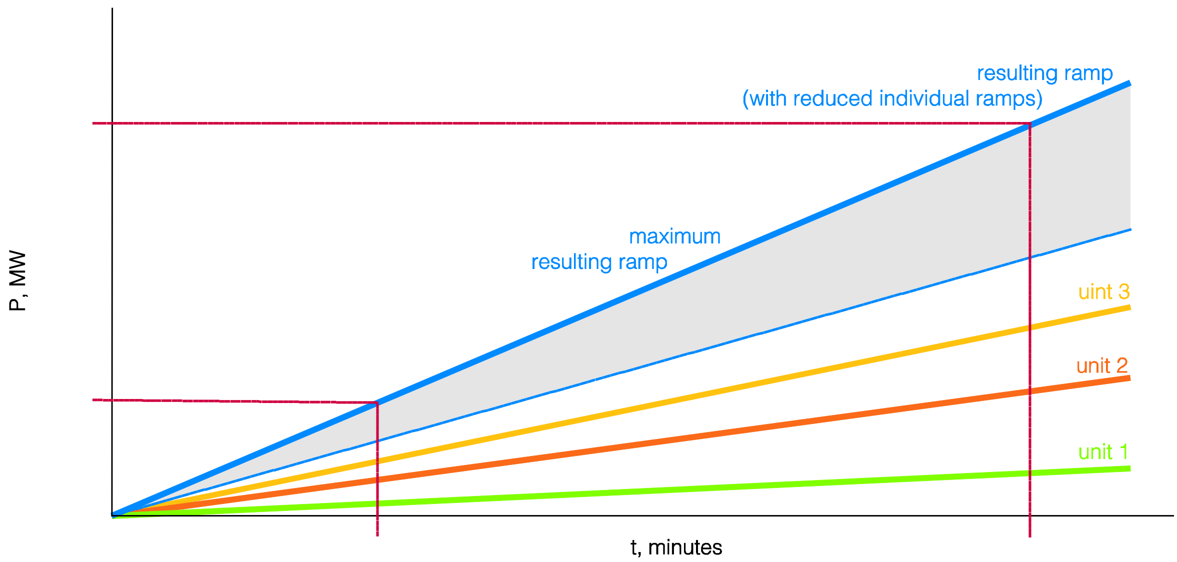

Figure 17 Using control systems to combine multiple units for greater ramp rates (Schröck and Dürr, 2013)

6.2 Turbine control systems

One of the functions of the turbine control system is to handle load changes while maintaining optimum efficiency and turbine life. Monitoring and control of the turbine are vital in preventing excessive thermal and creep-induced fatigue and also to prevent rubbing or excessive clearances resulting from differential expansion (Almstedt and others, 2007). Thus, the minimum requirement is to ensure that all temperatures and pressures remain within determined permitted ranges whatever the output or ramp rate.

Simple systems merely monitor the differential expansion between rotor and casing at a single point, then use a pre-set limit value to warn the operator to restrict conservatively the load change rate to ensure that no rubbing can occur. However, more sophisticated systems use monitored temperature and pressure data to calculate the expansion at different loads so that the associated clearances can be minimised at all times. This allows higher ramp rates, better efficiency and a total absence of rubs (Almstedt and others, 2007; FDBR, 2013).

To minimise thermal stresses, hot start-up has conventionally been carried out with the steam temperature higher than the turbine metal temperatures. However, this wastes steam, which has to be dumped to the condenser as the boiler is brought up to a sufficiently high outlet temperature (480–500°C). Modern units have control systems that enable the steam to be admitted at lower temperatures while the boiler is ramping. This allows the start-up time to be shortened by up to 15 minutes and less energy to be wasted (Quinkertz and others, 2008).

6.3 Plant control with self-learning predictive systems

There are advantages in installing comprehensive high level overall control systems that can co-ordinate the main plant systems by using predictive algorithms. Traditional control systems optimise the combustion process, steam cycle, steam turbine and emission control systems independently. Integration across the whole plant occurs through the actions of the plant operator. Modern automation systems now provide the ability to optimise the whole plant. This is highly beneficial in realising greater flexibility, in reducing stresses on the plant components while maximising efficiency and maintaining minimum emissions during load changes (Breeze, 2013a). Such systems, which are not yet widespread in power plants, may use mechanistic models to utilise the known principles of the various plant components, such as the furnace, boiler and turbine. Fuzzy logic may also be incorporated for less stable processes.

There are other situations where information on plant areas is not known or may not be available for other reasons. For these, a black box model may be used, which produces the predicted relationships from data inputs from around the plant without having access to specific detailed information (Breeze, 2013b). An example of a self-learning control system that operates in this way is ADEX's adaptive predictive technology that has recently been used in simulation of a CO_2 capture oxyfuel CFBC plant as part of a European FP7 project (Flexiburn). The high level control system was shown to work well without identification of the detailed dynamics of individual modules. Although this was a CO_2 capture application (and so is further discussed in Chapter 10), similar principles can be applied to non-capture coal-fired power plants (Slaven, 2013; Slaven and others, 2013).

6.4 Integration with other plants

Schröck and Dürr (2013) describe the emerging possibility of grids with greater flexibility, with operators employing remote monitoring of major units in an automated, closely co-ordinated mode, taking advantage of advanced control systems and the internet. For example, unavailability from component failure will be capable of being compensated through real-time data availability and forecasts, ultimately using neural networks for early identification of problems. Figure 18 shows the three principal elements of such a system envisaged by Siemens, embracing the local plant and central planning and diagnostics centres.

Marketing/generation planning with real time optimiser	marketing of current output excess and shortfall (real time) at each plant scheduling, taking account of current dynamic efficiencies of plants scheduling, taking account of current synchronisation point scheduling of the output forecast (day-ahead) supplied by power plant site and diagnostics and analysis centre scheduling of non-availabilities (already done).
Power plant site	communication of current output excess and shortfall (real time) advanced automatic checking program for starting drives and subordinate functional groups to ensure planned block start up time is met control system standby program to monitor drives and not ready for operation and implausible measured values to ensure planned block start-up time is met repair work/realisation of measures at economically favourable times (already done).
Diagnostics and analysis centre	monitoring of current dynamic efficiencies monitoring of current plant performance to ensure target output, gradients, control products and block start-up time, forecasting of load range between minimum technical and maximum (day ahead) in consultation with power plant site reporting of upcoming events.

Figure 18 Central and local elements and tasks of future power generation control systems (Schröck and Dürr, 2013)

7 Flexibility of CFBC plants

CFBC (circulating fluidised bed combustion) power plants use similar steam cycles to those of pulverised coal combustion plants, but the combustion system used in them is very different. The fuel is crushed, rather than pulverised, and combustion takes place at lower temperatures than in PCC systems in a highly mobile bed of ash and fuel supported on an upward current of combustion air. Most of the solids are continuously blown out of the bed then recirculated to the combustor. Heat is extracted for steam production from various parts of the system (*see* Figure 19). Limestone is also fed to the combustion system to control SO_2 emissions. Emissions of NOx are intrinsically lower than for PCC.

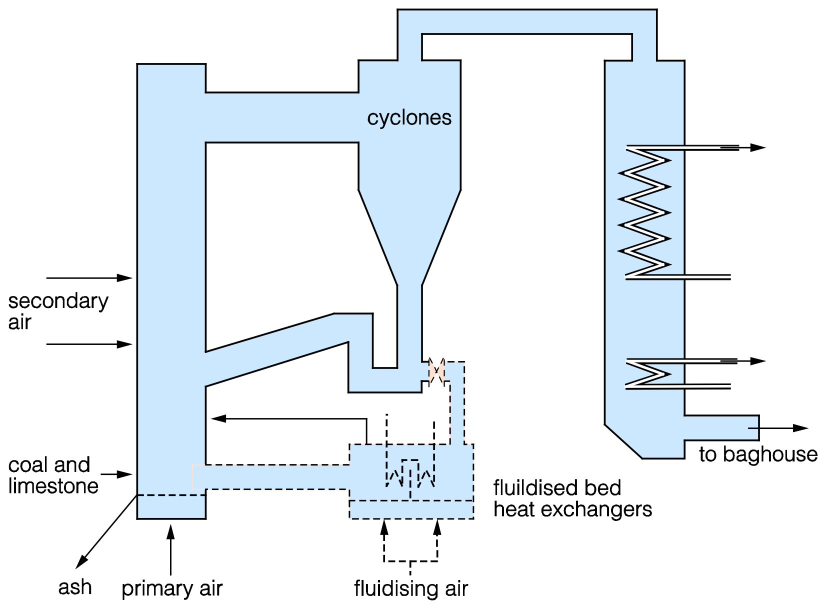

Figure 19 General schematic of a circulating fluidised bed boiler (Lockwood, 2013)

Refractory linings protect the tubing that forms the water-walls of the combustion chamber against erosion. Flue gases leaving the cyclones are generally sent to a conventional convective pass for steam superheating and other heat to the steam cycle. For more detailed descriptions of CFBC, *see* two recent IEA Clean Coal Centre reports, by Zhu (2013) and Lockwood (2013).

The flexibility issues of the turbine and water/steam cycle would be expected to be similar to those of pulverised coal plants. The essential differences from PCC units lie in the boiler and fuel feed and combustion systems. These can limit minimum load to about 40% of MCR in the absence of supplementary fuel. However, load following capabilities can be similar to those of PCC units: part loads down to 25% of MCR and load change rates of up to 7%/min are said to be possible (Mills, 2011).

Start-up times for some units can be longer than for similarly sized PCC plants. CFBC is less well suited to on/off cycling, as the bed temperature needs as far as possible to remain within normal operating range, and there can be potential for refractory damage (Zhu, 2013; Mills, 2011).

Wide or rapid temperature changes occurring during start-up, shut-down or load following can cause damage in the combustor and loop seal areas. However, a number of units have been cycled for some years, apparently without problems. Foster Wheeler offer for their Compact CFBC boilers a reheat steam bypass system for reheat steam temperature control during start-up and shut-down. The design also provides in-duct and over-grid start-up burners to shorten start-up times and save fuel (Mills, 2011).

8 Flexibility of IGCC plants

Coal-fuelled IGCC (integrated gasification combined cycle) power generation uses a combination of gas and steam turbines to produce electricity, rather than simply a steam turbine as in a PCC plant. Figure 20 shows the principle. The feed coal is converted to a fuel gas in a gasifier, which is generally of entrained flow design, fed with oxygen from an air separation plant. The fuel gas is subsequently cleaned of particulates and impurities before firing in the gas turbine to generate power. Hot exhaust gas from the gas turbine is passed through a waste heat boiler, where steam is generated for the steam turbine, which produces additional power. Steam available at suitable pressures from the gas production and cooling stages is also used at various points in the steam cycle.

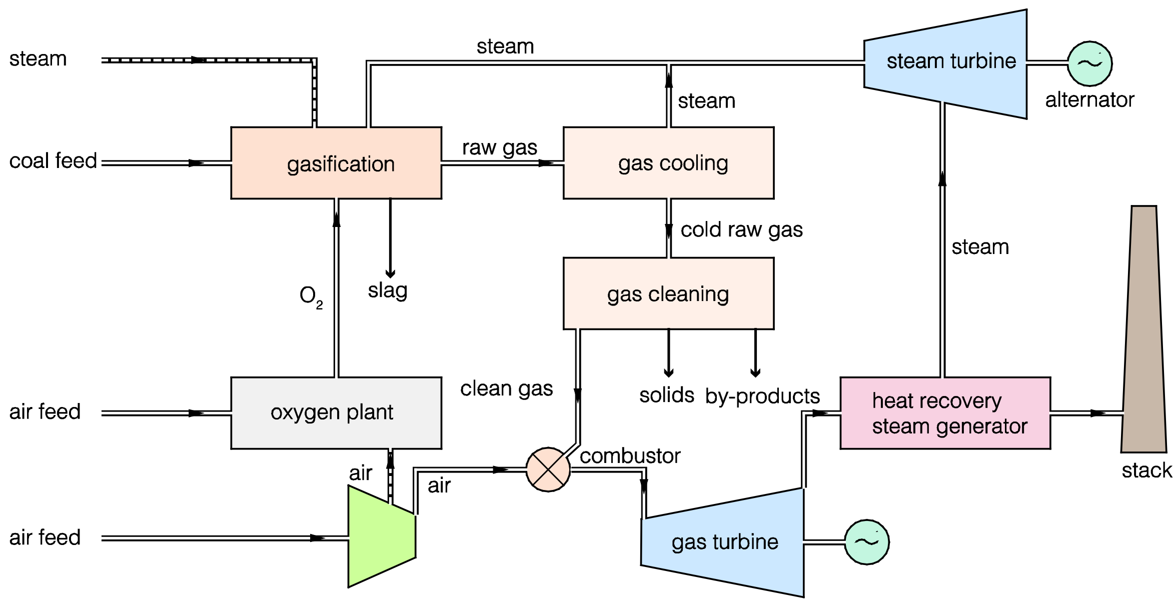

Figure 20 Integrated gasification combined cycle power generation (Henderson, 2008)

Some IGCC power plants supply the air separation unit (ASU) with air extracted from the gas turbine, while others use separate motor driven compressors. Alternatively, a combination of both may be used (partial integration). Higher degrees of integration favour higher thermal efficiencies, but start-up times can be longer, as individual process areas need to be brought on-stream in sequence. Partial integration is probably the best choice of ASU configuration for a standard IGCC as a starting point for achieving flexibility without sacrificing too much efficiency.

IGCC systems have not hitherto been designed specifically for high flexibility and the minimum load is conventionally about 40–50%, mainly determined by the achievable minimum outputs of the entrained flow gasifier and ASU. However, if two gas turbines are installed, this will give more scope for reduction, but the excess syngas needs to be used in some other way. One way is to make provision to store it at times of low load. It can then be fed to the turbine during periods of high electricity demand. Alternatively, at the expense of adding to the complexity, IGCC plants can be designed as polygeneration (multi-product) systems. These are able to vary the balance of multiple products, including electricity, liquids and synthetic natural gas (SNG). Polygeneration plants are discussed in Chapter 10, and an IEA Clean Coal Centre report is devoted to them (Carpenter, 2008).

Temporary storage of syngas and over-sizing the ASU to allow liquid oxygen and nitrogen storage, where integration allows, are potential means of increasing load range. At low demand, excess power would be used by the oxygen producing plant. Another suggestion has been that natural gas might be added to the syngas to increase ramp rate and output. The ramp rate of a straightforward IGCC system, as shown earlier in Table 2, will be determined by the gasifier and ASU ramp rates, and is, typically, about 3-5%/min, and so not very different from that of many older PCC units (Butler and others, 2013; Chalmers, 2010; Mills, 2011; Domenichini and others, 2013).

Some gasification systems use a largely air feed to the gasifier. An example is MHI's air-blown entrained gasification process. A 250 MW IGCC demonstration (now commercially operating) using the technology at Nakoso in Japan has achieved its design ramp rate of 3%/min and a minimum load of 36%. Start-up time was 15 h. There are plans to reduce the minimum load further (Watanabe, 2012).

Conceptual IGCC designs suggested for greater flexibility include some incorporating electrolysis. These could use excess power from the plant or from the grid, as appropriate, to provide additional hydrogen for the methanation of the syngas to SNG, while integrating heat from the exothermic SNG synthesis within the steam cycle (Butler and others, 2013; Wolfersdorf and others, 2013).

There has been relatively limited experience with IGCC power plants and these were not designed to meet rapidly changing and highly variable loads or rapid start-up or shut-down. It is therefore not yet clear how much operating flexibility will actually be obtainable with development. The fully-integrated Willem-Alexander IGCC plant at Buggenum in the Netherlands was operated as a commercial unit in load-following mode for over ten years until 2013. This plant was closed on 1 April 2013 on economic grounds (Barnes, 2013; Nuon, 2013). If IGCC plants start to be ordered in large numbers, designing for flexibility will become more important and further new approaches to achieving it may emerge.

9 Flexibility of future advanced USC technology

Manufacturers and utilities are working to achieve efficiencies of about 50% (LHV basis) and higher, by using steam conditions of 700–800°C at pressures of 35 MPa in advanced ultra-supercritical (A-USC) pulverised coal-fired plants. Superalloys based on nickel will be used in these systems. They are much more expensive than currently used steels, but only the highest temperature parts would be fabricated from them. Superalloys are already established in gas turbine systems, but component sizes in a coal plant are larger, the chemical environment is different, and pressure stresses are higher. Consequently, new formulations and fabrication methods are necessary. Activities to develop A-USC are in Europe, Japan, the USA, India, China and Russia. An IEA Clean Coal Centre report describes recent developments (Nicol, 2013b).

There is no experience with an operating A-USC plant, but such plants, like all other fossil-fired plants, will almost certainly need to have the capability to operate flexibly to be used in power grids with high capacities of renewable energy units on the system. However, nickel based alloys have the disadvantages of low thermal conductivity and a high thermal expansion coefficient (*see* Figures 21 and 22). These properties would potentially give rise to higher thermally induced stresses during changes of steam temperature than are encountered with the steels used in current plants. Work on the design and development of the superalloy components will have to overcome this if the A-USC plants are to achieve adequate flexibility for use in power markets such as in Europe (Gierschner and others, 2012).

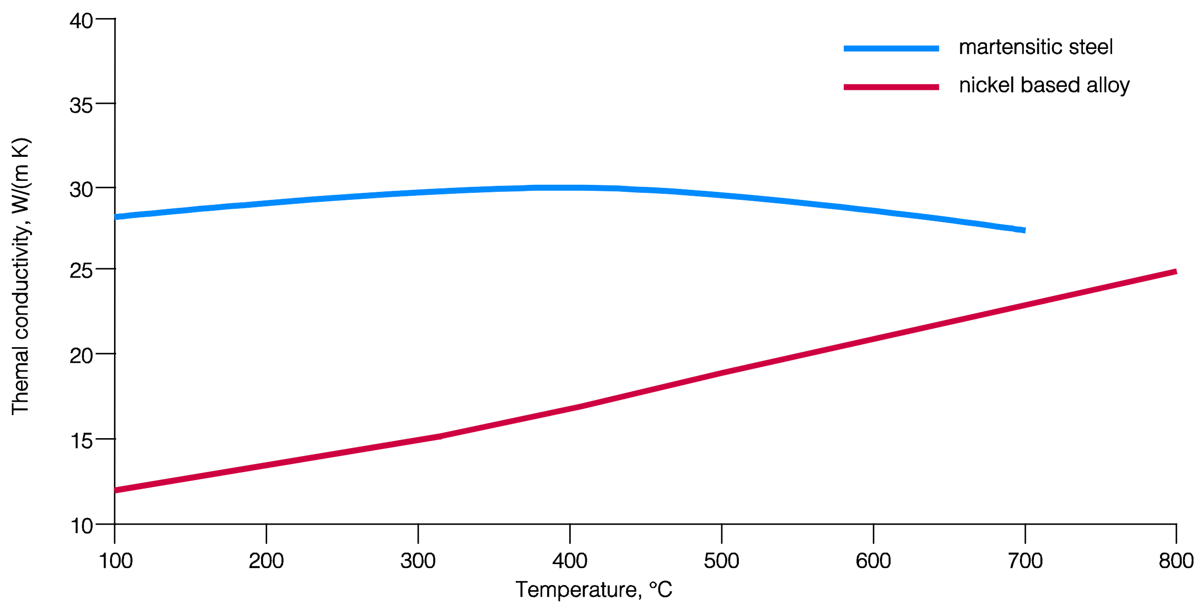

Figure 21 Thermal conductivity of a nickel based alloy and of a martensitic steel (Gierschner and others, 2012)

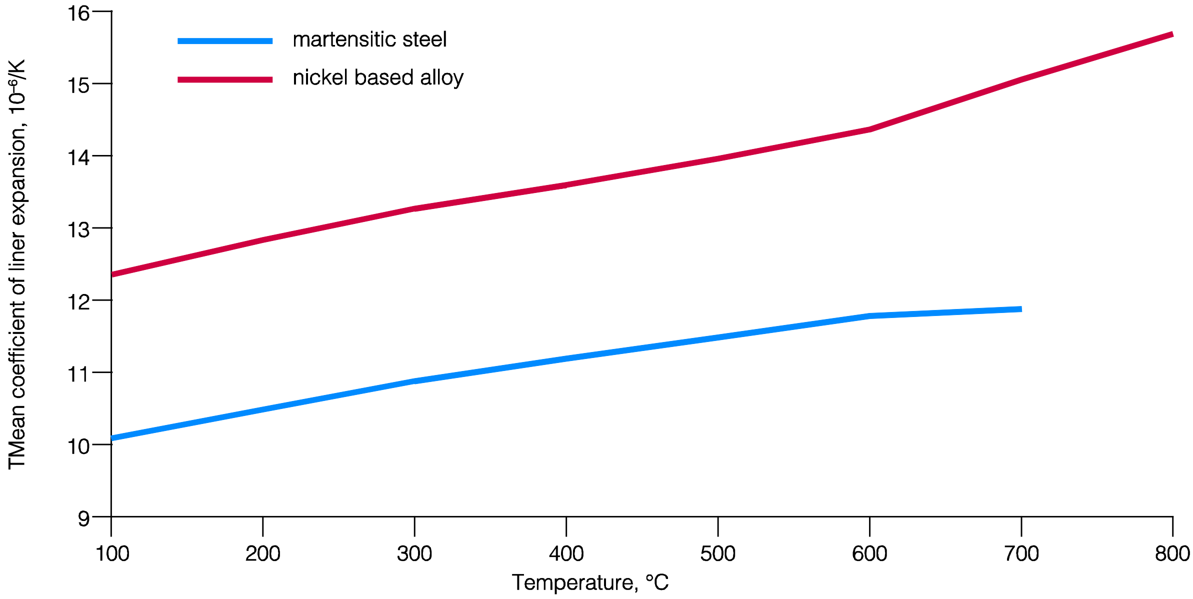

Figure 22 Thermal conductivity of a nickel based alloy and of a martensitic steel (Gierschner and others, 2012)

Table 6, taken from a graphical representation (in Busekrus, 2012), compares predicted start-up times for 600°C and 700°C technologies. A more detailed representation of the cold start-up metrics predicted for a 700°C, 35 MPa A-USC unit, is shown in Figure 23. This includes predictions of parameters such as the feedwater flow, steam flow, steam temperatures, steam pressures and turbine speed over the long run-up in the various areas of the plant. Laboratory test programmes using capacitive creep strain sensors, to assess the creep performance of superalloys, and modelling of creep-fatigue within the MACPLUS part of the A-USC programme in Europe are referred to by Kranz (2013) and Zanin (2013).

Table 6 Predicted start-up time for USC and advanced USC plants, minutes (Busekrus, 2012)

	600°C	700°C
Hot	120	130
Warm	200	300
Cold	320	430

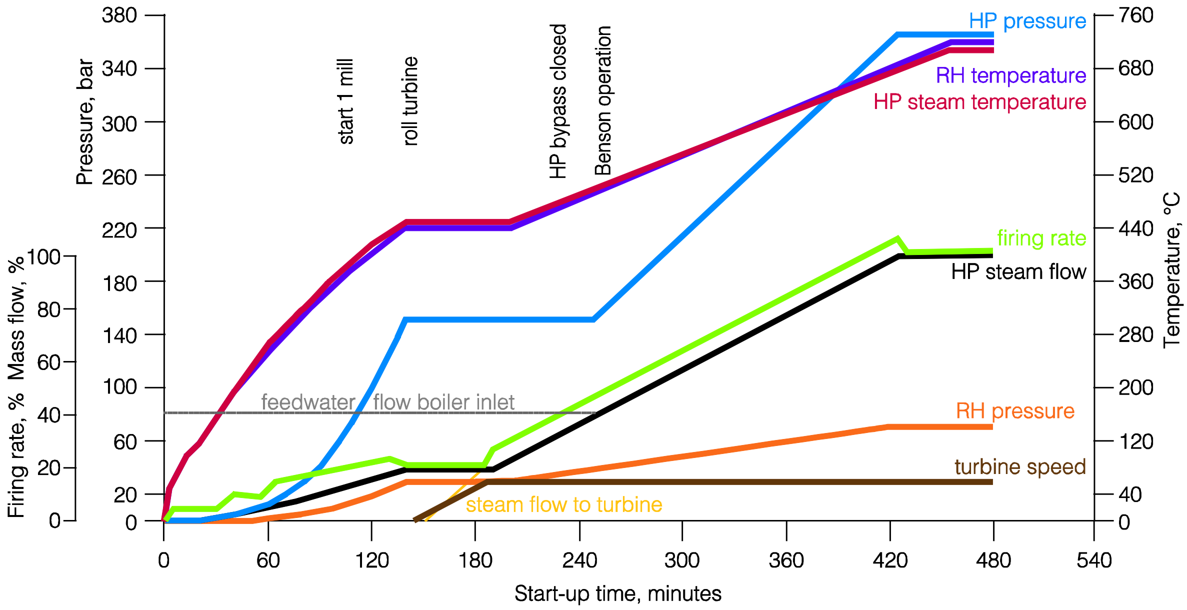

Figure 23 Predicted start-up dynamics for an A-USC (700°C) unit (Busekrus, 2012)

In summary, it not known at this stage for certain how much flexibility A-USC plants would be capable of in practice, but development of the required materials and their associated component fabrication techniques needs to be reconciled with the requirement for it (Wolff, 2012). If it turns out that sufficient flexibility cannot be achieved, such units will need to be restricted to base load application, which will leave them most suited to countries where higher, more stable capacity factors for coal-fired plants are likely to be sustainable, for example, in some Asian countries.

10 Flexibility of future coal-fired power plants with CO_2 capture

Predictions are that coal-fired plants incorporating CO_2 capture and storage (CCS) will be operating in significant numbers from about the mid-2020s, with major deployment during the 2030s (IEA, 2012). A number of IEA Clean Coal Centre reports from recent years described the technologies being developed (*see, for example,* Davidson, 2007, 2009, 2011, 2012). If and when carbon emissions prices become significant, CCS plants should be able to operate at higher capacity factors than plants without CO_2 capture because of their requiring fewer emissions allowances to be purchased. A proportion of these may provide base load, alongside nuclear plants (Davison, 2011). However, some CO_2 capture plants could need to operate flexibly, if wind and solar energy plants are called to operate first to maximise their usage.

Studies are providing indications of how flexible operation of coal-fired CCS plants could be realised, at a cost. Table 7, from a paper based on a study by Foster Wheeler for the IEA Greenhouse Gas R&D Programme, summarises the main techniques being considered.

Table 7 Techniques available for improving the flexibility of CO_2 capture plants (Domenichini and others, 2013)

	USC PCC	IGCC	Oxy-combustion
Turning off CO_2 capture	√	√	–
Co-production and storage of hydrogen	√	–	–
Storage of liquid oxygen	–	√	√
Storage of CO_2 capture solvent	√	–	–
Buffer storage of CO_2 (for constant flow to final storage)	√	√	√

For post-combustion capture plant, a rapid increase in output could be achieved by temporarily diverting the flue gas away from the CO_2 capture unit, if regulations permitted. At the same time, the flow of steam to the solvent regenerators would be turned off, increasing steam flow to the LP cylinders. At times of low demand, the CO_2 capture plant would be reconnected to the flue gas path. The steam cycle would need to be designed to accept the resultant higher flow. It is possible that the ability of such a plant to ramp up in output could be better than that of a plant without capture. However, large vessels for storage of CO_2-laden solvent would be needed if long periods of peak load were to be satisfied. Stored solvent would be regenerated at times of low power demand, when steam would be diverted to the regenerator, and achieving lower than normal minimum loads would then be possible. The large quantity of solvent that would have to be stored would mean that operating at peak output for long periods of time would not be attractive. Different variations would have different part-load efficiencies and economics (Lucquiaud and others, 2009; Chalmers and others, 2011; Mills, 2011; Domenichini and others, 2013; Mac Dowell, 2014).

Integrated gasification combined cycle (IGCC) power plants with CO_2 capture could be designed to allow hydrogen to be produced and stored, for firing in the turbine later. The gas production and power generation processes would thereby be decoupled. Both combined cycle and open cycle hydrogen-fired gas turbines could be used, further increasing flexibility. The gasification, CO_2 capture, transport and storage equipment would operate at base load, which would avoid potential practical difficulties of flexible operation and reduce costs. However, variable load operation of hydrogen gas turbines would need to be confirmed (Davison, 2012; Domenichini and others, 2013).

Oxygen production consumes considerable quantities of power, and it would be possible to develop IGCC plant designs allowing diversion of excess power to the oxygen producing plant, reducing net plant output, and thereby store the gas for use when demand is high, improving the economics (Chalmers, 2010; Mills, 2011; Butler and others, 2013; Domenichini and others, 2013). The latter could apply to non-capture IGCC plants and there was discussion of this in Chapter 8.

An IGCC plant design including two gas turbines and polygeneration could provide a turndown to 15-25%. This could improve utilisation, efficiency and, possibly, investment costs. If the chemical co-product were to be SNG, this could be stored in the natural gas grid. Figure 24 shows a version of such a system that allows pre-combustion CO_2 capture during operation of the gas turbine. This would require a dynamic operation of the synthesis plant, which is not usual practice (Butler and others, 2013). Variants of this concept, without CO_2 capture and incorporating an electrolysis cycle, were referred to in Chapter 8 (Butler and others, 2013; Wolfersdorf and others, 2013).

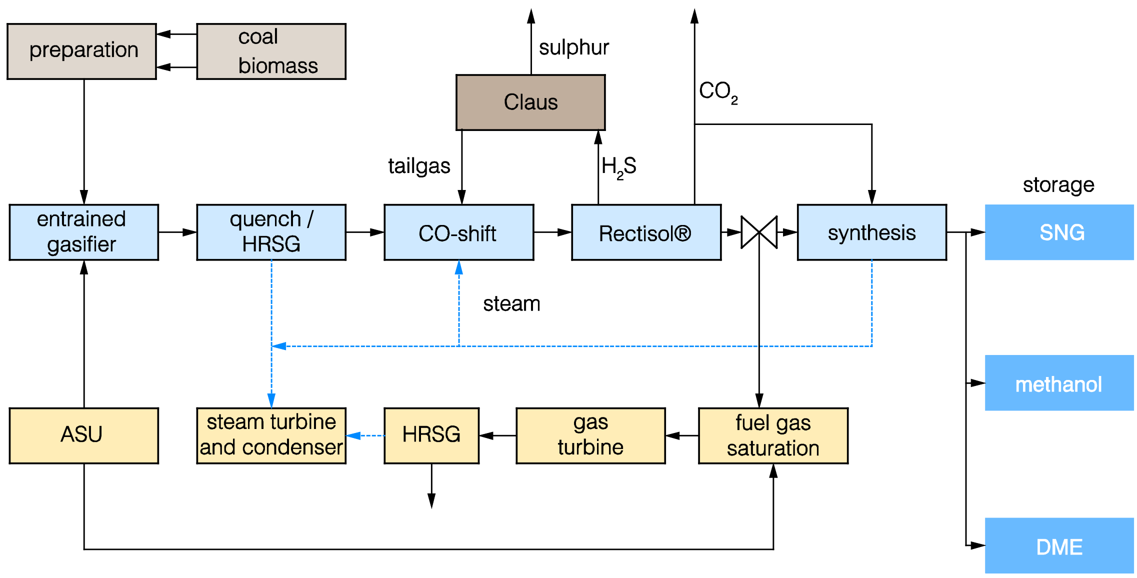

Figure 24 Simplified diagram of an IGCC polygeneration concept with dynamically driven synthesis and CO_2 capture (Butler and others, 2013)

Some gasification systems, such as MHI's process, use air for gasification. A feasibility study has been in progress on adding CO_2 capture after the wet gas clean-up at the 250 MW IGCC plant at Nakoso in Japan (*see* Chapter 8), but increasing the plant's flexibility is not mentioned as a specific aim of the CO_2 capture study (Watanabe, 2012; Barnes, 2013).

In oxy-coal systems, start-up on air will be followed by switching to oxygen plus recycle gas when the boiler has stabilised, which takes 20–30 minutes. Output flexibility within that timescale is likely to lie with temporarily switching off oxygen production and CO_2 capture (compression) and reintroducing air to the boiler. To add further flexibility and improve the economics there is also the possibility of employing oxygen storage with these plants (Chalmers, 2010; Domenichini and others, 2013).

Slaven and others (2013) have described the particular requirements of an oxy-fuel plant with respect to the control strategy to maintain close co-ordination of the various plant areas during load changes. These include managing:

- changes from oxy to air combustion or vice-versa at start-up, shut-down and as operating requirements vary;
- separate control of recirculating flue gas and oxygen to optimise combustion performance;
- balance between main components (air separation, boiler, CO_2 processing and turbine island) to maximise environmental and economic performance;
- control of flue gas composition prior to entering the gas processing unit.

A high level predictive control system across all plant modules would manage their functions and interfaces and adapt with precision and speed to changing dynamics, adjust appropriate variables to optimise efficiency and environmental performance, and so provide process stability. Such a control system would use adaptive predictive algorithms that would be able to anticipate and control the plant's changing dynamics.

Many of the systems described above could allow the flow of CO_2 to disposal to be maintained relatively constant. This is desirable because CO_2 compressors are typically limited to around 70% turndown. While greater turndown could be achieved by recycling compressed CO_2, this would impose a significant energy penalty (IEAGHG, 2012).

In summary, indications are that it may be possible to design plants incorporating CO_2 capture to have similar flexibility to their non-capture equivalents. However, cost considerations would influence the extent of flexibility realisable in practice. Some systems might allow high flexibility.

11 Summary and conclusions

A previous IEA Clean Coal Centre report considered the growing capacity of renewable energy plants around the world and the effects of their intermittent and highly variable output on the sort of role that coal-fired plants are having to fulfil (Mills, 2011). The effect is to force coal units in some countries to become swing suppliers. They have to deliver widely varying output so that total system supply matches load at all times. They also are being required, increasingly, to provide frequency control for grids because renewable power sources tend to be less well-suited to such duty, and grids are becoming of lower inertia. The challenges presented by this situation will only increase and become more widespread in the future. There is consequently a growing need for flexibility in coal-fired power plants for maintaining security of power supply. This present report focuses on the technical features that are available to enable plants to operate with rapid output changes with minimum detriment to integrity, efficiency and emissions.

There is a wide range of reported values for the load following rates of coal-fired power generation units, with ramp rates as high as 10% of maximum load/minute claimed to be achievable in some systems.

Flexible operation adds thermal and mechanical fatigue stresses to the creep damage that occurs anyway with time in the pressure parts of a coal-fired power plant. These, together with corrosion, differential expansion, and other effects, often synergistically, result in a reduction of the expected life of such components designed for base load. Operators and manufacturers have considered the mechanisms of these detrimental effects, and have come up with solutions. In addition, means of increasing flexibility that were constrained by non-life limiting considerations, such as better firing systems and better auxiliary motor drive systems, have been devised. The result is the availability of new and modified equipment, revised operating procedures, new specifications and further new ideas for making future plant designs more flexible while keeping efficiency as high as possible.

There are many features in specific plant areas that can be incorporated to give better flexibility. These include:

Boiler firing systems – changing to the size and number of mills and fitting of modern burners to achieve lower fuel feed rates to reduce number of shut-downs; introduction of lignite pre-drying (efficiency also improved); installation of hoppers and associated pipework to achieve indirect firing (efficiency at part load is then also improved)

Boiler pressure parts – use of alloys of improved strength to permit thinner section components; installation of external steam preheating to reduce start-up time; reducing minimum load through means such as modified evaporator designs, economiser water-side bypasses together with feedwater recirculation, and increasing the mass flow in the evaporator to achieve greater stability

Ensuring emissions control systems remain effective – installing means to maintain SCR exit temperature within specification at part load to avoid catalyst blocking and damage to the air heater;

minimising shut-downs and start-ups of FGD systems, and modernising control systems to reduce energy demand; for dust separation devices, ensuring adequate temperatures to avoid moisture condensation on particles

Turbine and water-steam systems – providing a turbine bypass so that the rate of steam temperature change can be managed as the boiler is starting up and shutting down, to reduce thermal stresses; use of a steam-cooled turbine outer casing to allow thinner sections for faster start-up; use of sliding pressure boiler-turbine systems for better control of turbine temperatures and reduced stresses; adding feedwater heater bypasses for greater load range; providing condensate throttling, feedwater heater bypass or HP stage bypass for frequency control; adding thermal (feedwater) storage systems for greater load range or frequency control

Control systems – installing new boiler control systems; installing new turbine monitoring and control systems; installing new self-learning control systems that co-ordinate the main plant systems by using predictive algorithms

Auxiliary plant – using flexible drives

Modifying plant configuration – retrofitting gas turbines integrated with the existing water-steam cycle for efficiency increase and increased output range and ramp rate.

The above measures are applicable to PCC (pulverised coal combustion) plants, but the flexibility aspects of the turbine and water-steam systems of CFBC (circulating fluidised bed combustion) plants are essentially the same as for PCC plants. The essential differences from PCC units lie in the boiler and fuel feed and combustion systems. The most flexible CFBC systems can have load change rates similar to those of similarly sized PCC plants, but start-up times can be longer than for PCC because of some tendency to suffer refractory damage from temperature changes.

IGCC (integrated gasification combined cycle) systems have not hitherto been designed specifically for high flexibility, and the minimum load and ramp rate are typically about 40–50% and 3–5%/min, respectively. These are comparable with older pulverised coal systems. Temporary storage of syngas is a possible way to provide more variable output. Another means could be to add facilities for oxygen storage. Some gasification systems use a largely air feed, but this does not appear to affect flexibility. Polygeneration (multi-product) IGCC systems would be able to vary the balance of different products and so allow greater load range, but it is uncertain whether response rate would be increased. There has been limited experience with IGCC power plants but, if they start to be ordered in large numbers, designing for flexibility will become more important and new approaches to achieving it may emerge.

Manufacturers and utilities are working to achieve efficiencies of about 50% (LHV basis) by using steam conditions of 700°C and above in advanced ultra-supercritical (A-USC) plants. There is no experience with an operating A-USC plant, but, like IGCC, they will almost certainly need to have the capability to operate flexibly. This could be difficult, as start-up time would be longer than for current USC units because of the properties of the superalloys that will be needed for the highest temperature components.

If necessary, it may be possible to design plants incorporating CO_2 capture to have similar flexibility to that of their non-capture equivalents, but cost considerations would influence the extent of flexibility realised in practice.

In summary, potential damage mechanisms from plant cycling duty are well known and the technical means exist for conventional combustion-based plants to achieve the necessary flexibility without unacceptable loss of plant life and thermal efficiency. Work is in progress on means to increase the flexibility of future systems. It is important that financial rewards are sufficient to cover the cost of maintaining grid balancing plants so that suitable fossil-fired capacity continues to be available to keep power supplies reliable.

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