Levelling the intermittency of renewables with coal

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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, China, the European Commission, Germany, India, Italy, Japan, 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

Coal-fired power plants are designed to run most efficiently and cost effectively when running at steady baseload. Renewable energy systems, such as wind and solar, are much more sporadic in their energy output, varying with weather conditions. The energy from renewable sources is currently prioritised for input into the grid in many countries, meaning that thermal plants such as those powered by coal or nuclear sources must now provide more flexible output to keep the available energy in the network at the required level. This ramping and cycling of coal plants puts a strain on the boiler and increases the risk of operation and maintenance problems. This report evaluates the different cost penalties of increasing the flexibility of coal-fired plants to cope with the intermittency of renewable power source, indicating that cycling operation can be expensive and, in some situations, costs can increase by orders of magnitude.

Acronyms and abbreviations

ABS	ammonium bisulphate
CCC	Clean Coal Centre
CFBC	circulating fluidised bed combustion
DSS	daily start and stop
EC	European Commission
EFOR	equipment forced outage rate
EPRI	Electric Power Research Institute, USA
EU	European Union
FGD	flue gas desulphurisation
GW	gigawatt
IEA	International Energy Agency
IER	Institute for Energy Research, USA
IGCC	integrated gasification combined cycle
LCOE	levelised cost of energy/electricity
MIT	Massachusetts Institute of Technology, USA
MWh	megawatt hour
Mtoe	million tonnes of oil equivalent
NREL	National Renewable Energy Laboratory, USA
OECD	Organisation for Economic Cooperation and Development
PV	photovoltaic
RPS	Renewable Portfolio Standards
SCR	selective catalytic reduction
USC	ultra-supercritical
VRE	variable renewable energy
WSS	weekly start and stop

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1 Introduction

Emission limits for pollutants from sources such as coal-fired power plants have been tightening for decades and continue to do so. Although a significant proportion of emissions can be controlled, many countries are moving away from conventional thermal-based power production to less carbon-intensive options. Individual countries and regions have set their own targets for increasing the proportion of energy produced from non-carbon sources, including the EU, North America and Japan. For example, more than 30 US states now have Renewable Portfolio Standards (RPS) which place an obligation on electricity supply companies to source power from renewable sources. California has a target of obtaining 33% of the State's power from renewables by 2020 (Mills, 2011). Scotland set an ambitious target of 50% of power generation from renewables by 2015 and appears to have almost reached that goal. An even more ambitious target of 100% renewables is set for Scotland for 2020 (Financial Times, 2015). Germany has a target of 35% by 2020 increasing to 80% by 2050 (Schiffer, 2014).

The European Commission's (EC) renewable energy progress report reveals that 25 European Union (EU) countries were expected to meet their 2013/2014 interim renewable energy targets. In 2014, the projected share of renewable energy in the gross final energy consumption of the EU was 15.3%. Europe is reported to have three times more renewable power per capita than anywhere else in the world (EC, 2015). Back in 2010 Green and Vasilakos (2010) noted that the EU had committed itself to 20% renewables by 2020 and that this could involve more than 500 TWh of wind generation, nearly seven times the level it was in 2010. Within Europe there are now more than one million people working in the renewable energy sector, worth over €130 billion a year, and €35 billion worth of renewables are exported annually. The renewables target has resulted in 388 Mt of avoided CO_2 emissions in 2013 and has led to a reduction in the EU's demand for fossil fuels 116 Mtoe (million tonnes of oil equivalent; EC, 2015). Currently the most common renewable energy sources are wind (as the lowest Capex and most mature technology) and solar PV (photovoltaic). Figure 1 is a simple graph which shows the growth in non-hydro based renewables in OECD (Organisation for Economic Cooperation and Development) countries since 1971.The share of renewables (around 22% in 2014, including hydro) in the OECD region is now greater than that for nuclear (around 19%) (IEA, 2015a).

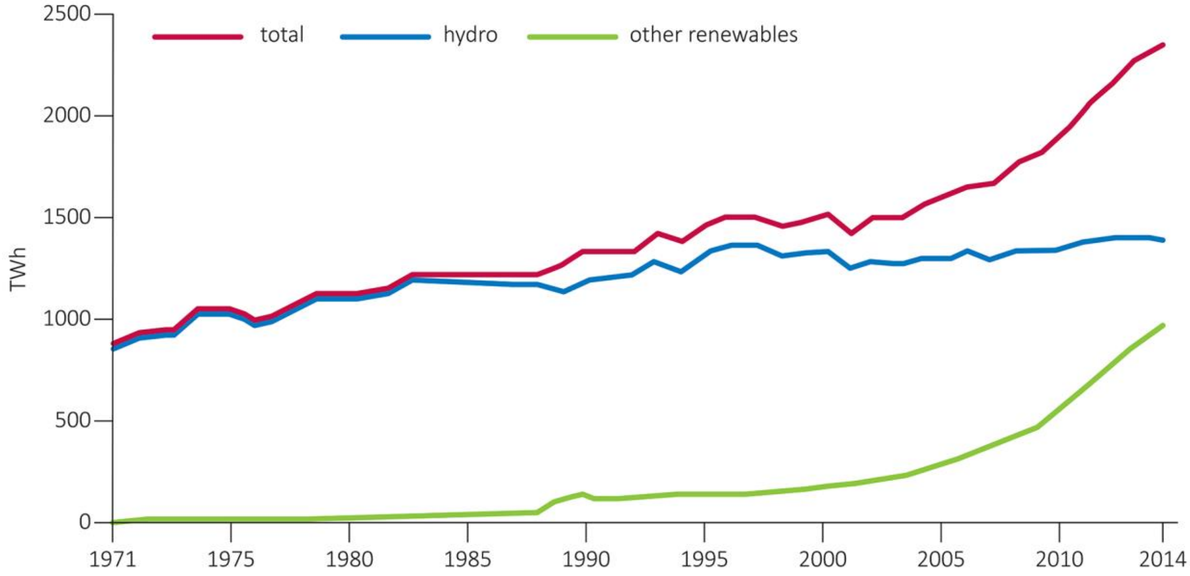

Figure 1 OECD renewable electricity generation 1971-2014 (IEA, 2015a)

To help meet ambitious national and regional targets, renewable energy systems are often allowed to 'free spill' into energy markets – that is, whenever electricity is produced from renewable sources, this electricity is guaranteed to sell. This differs from most existing systems which are based on planned baseload and predicted peaks, where the demand for electricity is met according to supply and demand with cost being the main deciding factor.

And so, whilst the growth in renewables is inevitable and necessary, it does not come without cost or complication. The intermittent nature of the electricity output of renewable systems means that they do not provide consistent electricity output to a demanding regional or national grid. In order to counter the intermittent and fluctuating nature of these systems, more reliable sources such as coal, oil and gas are called upon. Figure 2 shows the output from Minnesota wind farms throughout 2008 (Danneman and Lefton, 2009). The totals range from 0 MW to over 900 MW, varying significantly from day to day and, although not visible in the scale of this graph, from hour to hour. Solar energy systems tend to have a simpler, diurnal phase – on during the day and off overnight, although cloud cover can significantly affect solar power in some regions, often on a seasonal basis.

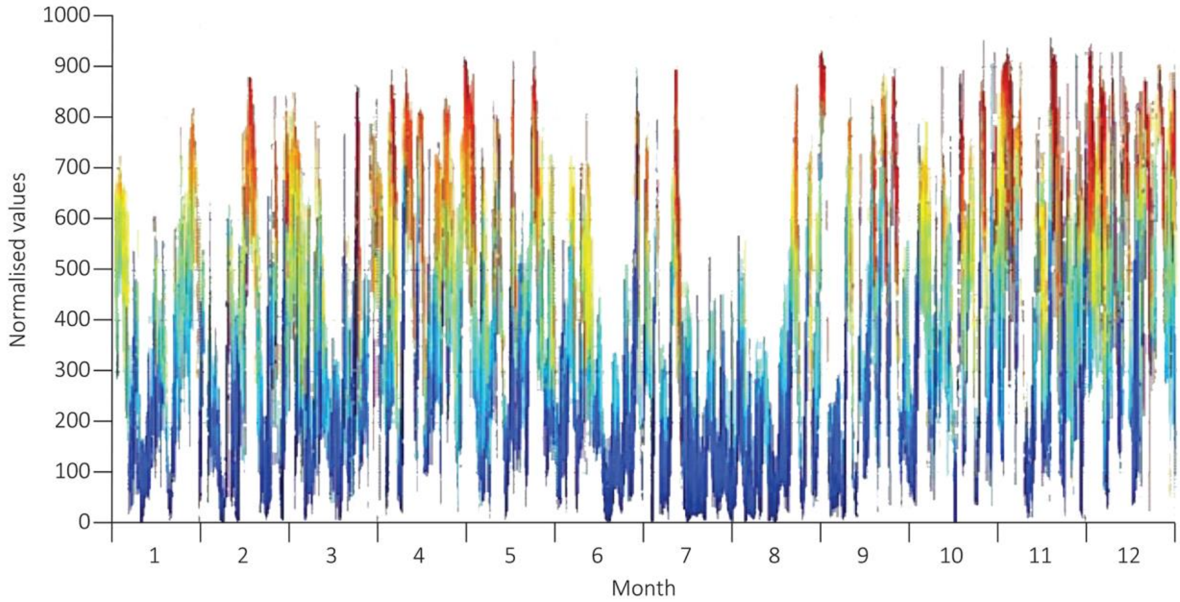

Figure 2 Wind output intermittency through 2008 in MN, USA (Danneman and Lefton, 2009)

Although weather, and thus wind and solar output, can be predicted to some extent, the accuracy of these forecasts is not ideal. For example, the UK wind output deviates from forecasts by 4% on average and, during 2013/2014, deviations were as high as 35%. Solar output deviates around 5% from forecasts. Wave/tidal power is regarded as 'highly predictable' but has still to reach a significant level of availability and market penetration (HP, 2014). As an indication of the potential variability in the output of renewable systems, Table 1 shows the contribution from different energy systems and their reliability during times of annual peak demand in the UK.

Table 1 Contribution of technologies to electricity system reliability at times of annual peak demand in the UK (HP, 2014)

Technology	Capacity factor (dependable capacity) as a percentage of maximum capacity, %	2013 UK maximum capacity, GW
Wind	7–25	11.0
Solar	0	2.7
Hydro	79–92	1.7
Tidal *	35	<0.001
Wave*	35	<0.001
Fossil and nuclear	77–95	78

* Few data available for wave and tidal

The table shows that, other than hydro, fossil fuel and nuclear plants provide the most consistent and dispatchable source of power at peak demand in the UK. Solar has 0% reliability simply because the table considers annual peak demand which occurs in winter, after dark, when there is a zero contribution from solar in the UK. In considering this and other data on the UK generating capacity, the UK Government concluded that the need for system flexibility will increase as the renewable capacity increases.

This means that, as countries such as the UK move towards more renewables, the stress placed upon fossil and nuclear plants to provide the balance of power will continue to increase (HP, 2014). However, fossil plants such as coal-fired units were designed to supply baseload energy with some capacity to ramp output up or down. These plants were not designed to ramp up and down rapidly in short periods of time to provide electricity to fill the gaps in grid output caused by renewable energy intermittency. It is this change in plant dynamics and the subsequent effect on plant operation and running costs that forms the focus of this report.

Biomass cofiring with coal or dedicated biomass combustion is a renewable source of energy and a dispatchable one. At the moment, the EU produces over 60% of its renewable energy from various forms of biomass (including biofuels and anaerobic digestion). The Clean Coal Centre has produced several reports on biomass combustion and runs an annual international workshop on this subject. The interested reader is recommended to check out our website www.iea-coal.org for further details.

Upgrading and/or addition of transmission lines, load demand control, energy storage and renewable curtailment are all options available to grid managers to control supply and demand. However, at the moment, some regions are still calling upon older coal-fired plants to alter their operation to ensure electricity demand is met and it is this situation on which this report focusses.

Previous reports by the Clean Coal Centre have looked at different aspects of renewable technologies and intermittency and the effect on coal electricity production. Mills (2013) looks at directly combining renewables with coal, for example through combined biomass and coal gasification. Although not directly related to intermittency, Lockwood (2015) looks at advanced sensors and the technologies available to monitor and control power plant performance in real time. Many of these sensors will provide the data required to monitor the effects of ramping on coal cycles and may help to manage these to keep costs and potential system damage to a minimum. Henderson (2014) produced an excellent review of methods to increase the flexibility of coal-fired power plants and some of this information is summarised within this report. An earlier CCC report by Mills (2011) looked at integrating intermittent renewable energy with coal plants, concentrating more on combining renewables with coal at source.

Many new coal-fired plants are being designed to operate at higher efficiency and with significantly more flexibility than older units. This report concentrates largely on the older units as it is these units which will be required to make the most changes in many countries. It summarises the effects of cycling on existing large thermal plants: – to evaluate the effects of increased start-up/shut-down patterns and of operating units at reduced and varied loads; to determine the increased maintenance requirements; and, ultimately, to estimate the increased costs. Evaluating the cost impacts arising from increasing the flexibility of coal operation is not simple as it must include consideration of the variability of pricing of electricity from the intermittent generators. Potential costs may also arise from adverse changes in greenhouse and other emissions resulting from sub-optimal operation of thermal plants in support of intermittent generators. These costs could be in the form of lost revenue from carbon credits or increased control costs or even fines from increased emissions. But some of the most significant costs may arise due to the technological and operational changes required at the equipment level, the investment required in optimisation and modernisation of plant control strategies to mitigate impacts of variable load operation and/or two-shift operation. The largest cost to utilities may well be the cost of providing 'replacement energy' to cover for plants out of service due to a forced outage (Danneman, 2016).

Chapter 2 explains the challenges of intermittency – of matching supply and demand and determining the order of dispatch. Chapter 2 also briefly looks at the potential issues of compliance with emission limits for plants operating in a more flexible mode. Chapter 3 then considers the cost of intermittency in broad terms, such as funding, electrical wholesale prices, required upgrades to the grid, and levelised costs. In Chapter 4, the actual changes to, and effects on, plant performance and operation are reviewed, highlighting issues which may add to operation and maintenance costs. Although intermittency issues are common to many countries, Chapter 5 looks at just three example countries (USA, UK and Germany) to illustrate the common problems encountered.

2 Intermittency – understanding the challenges

The majority of coal-fired plants in operation around the world today were designed to work at baseload, occasionally ramping up or down at peak or quiet periods, as required. There appears to be no defined operation rate or capacity factor defining baseload but it is commonly held to apply to plants operating around 80–85% capacity factor. As the variable output from renewable energy systems increases in many regional grid systems, it is becoming more common for these plants to have to increase their flexibility in order to change their output much faster and much more frequently than in the past. This puts new stresses on the plant which can require investment in changes in plant equipment and operation.

At the 2011 MIT (Massachusetts Institute of Technology) Energy Initiative Associate Member Symposium, the published summary document included the following statement (MIT, 2011):

"*In the absence of economically viable large-scale storage, the burden of maintaining system reliability will fall mostly on the flexible operation of thermal generating units, such as coal, natural gas and nuclear (hydropower is available in some regions). However, the ability of these plants to operate flexibly is limited by both physical constraints and economic profitability considerations*."

This chapter briefly summarises the issues associated with increasing the flexible operation of older coal-fired units.

2.1 Matching supply and demand

Ideally, electricity output is managed and controlled through pre-arranged agreements between suppliers and generators to produce the required amount of power over a set period of time. When the time scales shorten and the amount of power required by consumers cannot be fully guaranteed, then balancing supply and demand is more of a challenge.

In many places, such as the USA and some EU member states, the commitment to renewables generation is currently such that they are 'must run' technologies. That is, in order to reach high targets for renewable energy, all the energy that these systems produce must be fed into the grid (IER, 2012). If the grid cannot accept this electricity at a certain time (such as a surge in wind power during the night when demand is low) then payments are still made. This represents a significant change in the way that electricity is bought and managed. Since the output from these renewable sources is significantly harder to predict in advance (due to the often inherent unpredictability of weather systems, *see* Figure 2), the required output from thermal plants to fill any gap between supply and demand must be changed more frequently and, often, as cheaply as possible.

Figure 3 shows a typical 'load duration curve' for a region of the grid and represents the electricity demand (load) for each hour, from the highest demand hour down to the lowest demand hour.

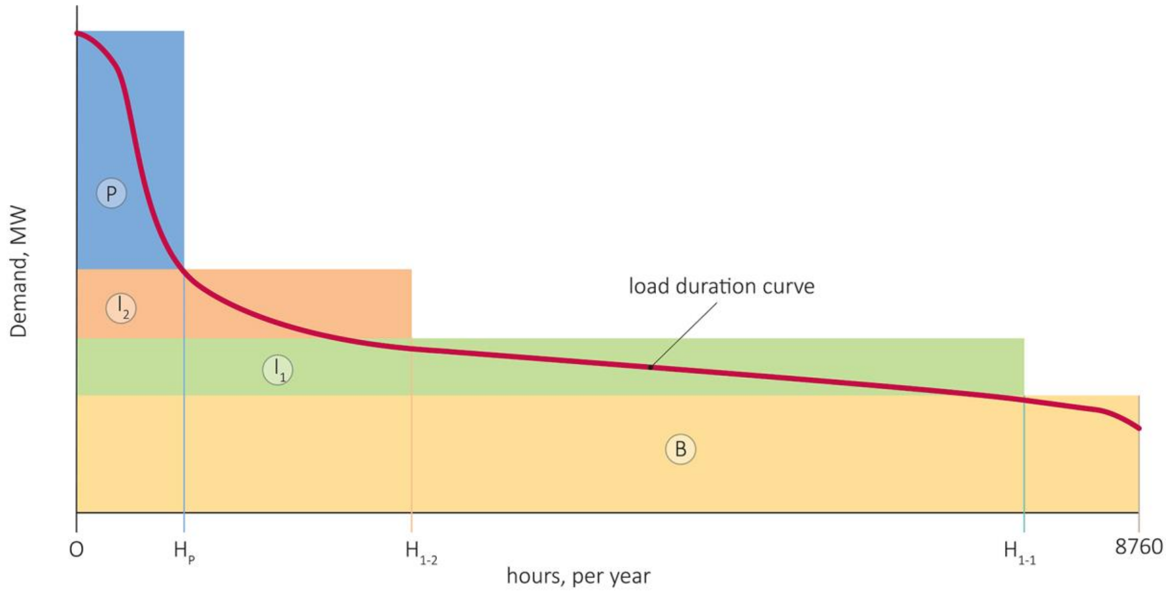

Figure 3 Examples load duration curve and generation types (Lesser, 2013)

As shown in Figure 3, baseload generators, B, operate for all 8760 hours of the year. There are two types of intermediate generators (I_1 and I_2), unspecified but shown to differ in terms of variable costs – the higher cost intermediate generators run less often than the lower cost generators, for economic reasons. At the top there are the peaking resources, P, which operate for the least amount of time during the year. These units will only be called upon when absolutely necessary and will be chosen according to the lowest bidder. But the costs of running these units still tends to be significantly higher than running baseload units. Due to the intermittency of renewable power, coal-fired plants are now effectively being moved from zone B into Zones I_1, I_2 and even P. According to Lesser (2013) total payments made to generators depend on their overall availability when needed. A generator with a history of frequent breakdowns and forced outages will be less useful to the grid and will be paid less than a unit which is always available and runs in a reliable manner – a peaking unit that is not available to meet peak demand has little or no economic value. This is where coal fired plants are far more useful than intermittent technologies. However, coal plants run far more efficiently as baseload, B, plants than as peaking, P, plants and, of course, do so at lower cost to the plant operators.

Danneman (2010) has produced Figure 4 which neatly summarises the ranking of electricity generation within an example market of the USA. The baseload of power is a combination of those renewable energy inputs that MUST be taken (due to renewable obligations and feed-in guarantees) and generation which is reliable and secured through long-term contracts, including some thermal. Many of these plants will be running at a minimum level, providing a small amount of electricity but effectively being 'hot' and ready to ramp up if required (this is discussed more in Chapter 4). The remaining, fluctuating portion of the dispatch is completed through generation from dispatchable sources (such as fossil fuel plants) which must compete to provide this energy and do so by the cheapest means possible – 'economic dispatch in merit order'.

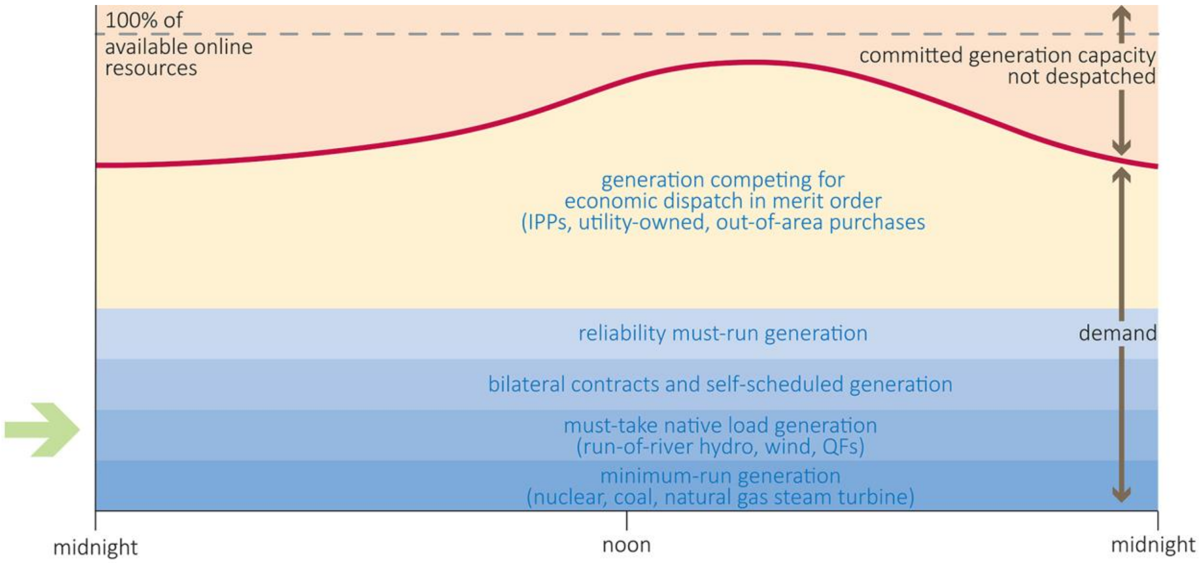

Figure 4 Building the economic dispatch stack (US GOV, 2005)

At the top of Figure 4, the moving red line indicates the variability of output from the non-dispatchable sources – the renewable sources. When meeting sudden changes in demand, grid managers rely on the most flexible of plants for the fastest changes. Open-cycle gas plants and pumped hydro facilities are the most suitable for these rapid changes in output. When changes in demand are more predictable, mid-merit power plants such as combined cycle plants are used. Base load plants, which are largely nuclear, coal and gas-fired plants, have been designed for constant output and face more of a challenge when asked to respond quickly to changes in demand (Mills, 2011).

The price of electricity as it is dispatched is dependent largely on the marginal costs – the incremental cost due to the generation of one additional unit of kWh. Short-term marginal costs take into account fuel costs and any relevant CO_2 costs whereas long-term marginal costs additionally take into account capital costs and operation and maintenance costs (discussed more in Chapter 3). And so, on a cost basis alone, the current (2014) merit order of dispatch of plants in most EU countries is as shown in Figure 5 (Haas, 2014).

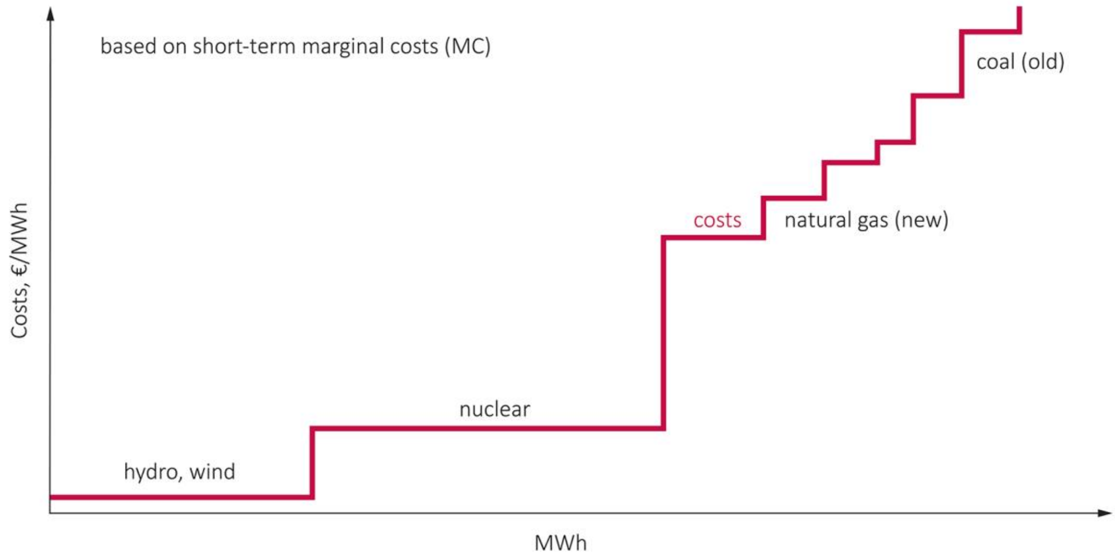

Figure 5 Merit order curve of supply (Haas, 2014)

Figure 5 shows that coal is often the last option for providing flexible short-term electricity. Haas (2014) suggests that the long-term marginal costs of coal, nuclear and wind are similar, with coal being slightly lower. However, in terms of short-term marginal costs, coal has the highest values due to fuel costs. This is because, when considering short-term marginal costs, the costs of plant construction and maintenance are not included. Since wind and hydro do not have to pay for fuel and, with nuclear the fuel is within the plant budget, fuel costs have the most effect on the cost of electricity produced by fossil fuel plants. The use of coal to provide electricity in these circumstances is therefore a necessity rather than a choice. This merit order data was based on 2014 costs and this may change over time due to factors such as variations in fuel costs. Levelised costs, which do take plant construction and maintenance into account, give a different picture of plant costs – these are discussed more in Section 3.4.

2.2 Managing intermittency in practice

Table 2 shows the options available to the grid when electricity supply from the available systems are suddenly lower than demand from end-users.

Table 2 Response time of system inertia and balancing services (HP, 2014)

Name of service	Response time	Time to maintain
System inertia	0 seconds	~10 seconds
Frequency response	2–30 seconds	Up to 30 minutes
Operating reserve	2–240 minutes	5–120 minutes

There is some inherent latent energy available within the system, especially from thermal plants with turbines. For example, if there are enough turbines available within the electricity grid, then these can provide a few seconds of continued power after plant operation is halted. The service options included in Table 2 are as follows:

- system inertia may also be provided within some energy storage systems (hydro);

- frequency response represents power that can either be contracted in advance to act as a bridge or can be bought from a competitive market when required;
- operating reserve covers plants which can be started up, after a short period (response time) to replace lost power from the system.

Whilst the data in Table 2 suggest that reserve power can be met quite quickly, this depends on the systems available to the grid. Some of the required power will be met by drawing reserves from over production or from storage or by ramping up plants that are already in operation. However, it is important to note that the average coal-fired plant can take 12 hours to start from a cold-start situation (after sitting idle), 4 hours from a warm start and 1 hour from a hot start, although this does vary from plant to plant (Henderson, 2014). This is discussed more in Chapter 4. In some systems, capacity may provide 'spinning reserve' which can be called into service within a very short period of time (minutes) to respond to the loss of a unit, transmission line or a rapid change in wind generation. Conversely, a unit may trip offline from high load, which may occur due to emergency safety switches designed to protect the system from accidents such as lightning strikes. During these events, the balance of units connected to the grid can absorb the loss of that unit for a few seconds through rotating mass (inertia) (Danneman, 2016).

In Denmark, one operator has determined that 300–500 MW of back-up capacity is required for every GW of wind power. In the UK it has been shown that building 25 GW of wind capacity (around half of UK peak demand) would only decrease the need for conventional nuclear and coal by around 6.7%. Further, around 30 GW of spare capacity would need to be on immediate call to provide a normal margin of reserve, around 2/3 of this required to cover for the intermittency of wind (Mills, 2011). And so, although the amount of renewable energy is currently increasing, there is not a concomitant or equal reduction in coal or fossil fuel capacity. What is actually happening is that many plants are being maintained and even new plants being built with the main intention of providing back-up to more intermittent energy sources. This means that plants are being built on the understanding that they will not be running at base-load but instead will be required to ramp up and down to fill the gaps in supply. This report concentrates on the changes required in older plants to achieve this flexibility.

In order to keep the stress on thermal units down and, more importantly, to keep the costs of electricity down, most grid operators will try to balance the input and output from the system as much as possible with the most cost-effective methods available. There are four main flexibility options within most grid systems (HP, 2014):

- Connection to other networks – for example, between states in the US and countries within the EU.
- Electricity storage – pumped hydro is available in some but not all regions. Electricity storage is commonly very limited, hence the problem of intermittency. If, and when new means of large-scale energy storage are made commercially viable and widely deployed, renewable energy will become more dispatchable.
- Changing patterns of demand – reduction in the demand for power to prioritise the available power to where it is needed most. This is commonly through load shedding agreements whereby large

electricity users, commonly industry, are paid to reduce requirements when the supply is low but may also be provided cheaper power at times of high or over supply.

- Flexible fuel-burning generation – coal, oil and gas-fired plants.

The final option in the list above is the main subject of the remainder of this report.

Figure 6 shows the principal elements of a system designed to promote the automation and coordination of input from different plants into a grid system.

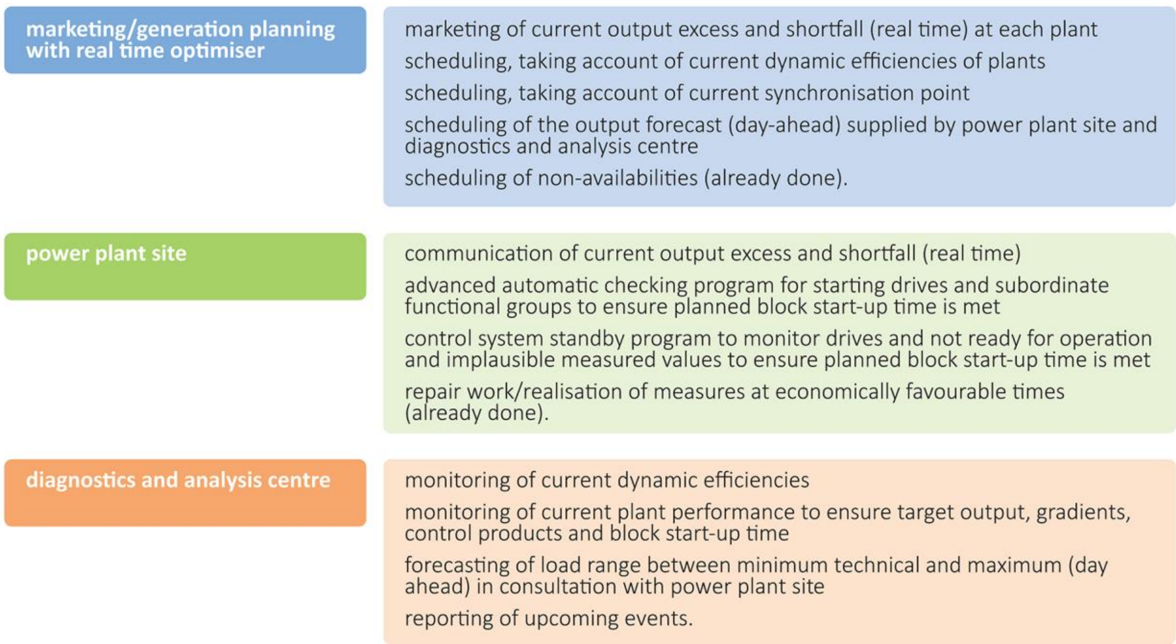

Figure 6 Central and local elements and tasks of future power generation control systems (Schröck and Dürr, 2013)

The figure breaks down the requirements for integration into three main elements. For the generator, the priorities centre around scheduling to ensure that there is enough power available for when it is required. For the power plants, the priorities are more performance based, focusing on programmes for monitoring and control of plant operation. Finally, the priorities for the analysis centre and the collation of information and data are to match supply with demand and to forecast and advise of potential future events (Schröck and Dürr, 2013).

For generators or utilities with more than one plant available, there is a choice to be made as to which plant or plants are asked to ramp up or down – there must be a balancing of the fleet. Lefton and Besuner (2006) reported on a study covering over 300 coal-fired units, including plants in the USA, Canada and Europe, covering plants from 15 MW up to 1300 MW. The study suggested that older coal-fired plants can be more rugged and cost effective to cycle than the newest combined cycle units, with low fuel costs helping to keep coal as a favoured option. During periods when electricity values are high, load following is easier than when electricity costs are low – the latter requires a decision to be made as to whether the plant should shut down and incur cycling damage or operate at minimum load. In times of peak demand, plants may have to run above their maximum continuous rating. This may be a costly way to operate but may actually be the most cost-effective option in a fleet, avoiding the start-up of another unit from cold. There is also the option of load-shedding – asking consumers to lower requirements in periods when demand is too high. This can also be costly.

Although less common, there is the issue of overproduction of electricity from renewables on especially windy or sunny days. Again, determining which plants should slow down or shut down will be determined depending on cost, ease of shift and so on. Since wind usually has priority into the grid, removing it from the system, as has been necessary in some incidences, requires approval from the grid operators (Mills, 2011).

2.3 Changes in emissions and compliance issues

The change in operating requirements for coal-fired plants can have an effect on all emissions. Chapter 4 contains more detail on technical changes which may be required to ensure that emission control technologies continue to work effectively within flexible operation while this section gives a more general overview of potential compliance issues.

According to Kemp (2013), conventional coal plants can turn down their output by a maximum of about 50% without emission issues – any lower and the efficiency drops such that they risk violating air quality controls. Kemp (2013) also suggests that existing coal plants which continue to operate to provide power up to 2030 "will operate in an increasingly inefficient and costly fashion, with increased carbon emissions per unit of power generated" as a result of the increasing demand for them to operate in a flexible manner. This suggests that any increase in CO_2 from coal-fired plants which may arise as a result of less efficient operation will offset the benefit of the renewable systems being used – that is, any increased emissions from coal plants running less efficiently will counteract some of the decrease in emissions due to the replacement of fossil fuel with renewable energy sources. In general, the proportion of CO_2 savings from renewables offset becomes greater as the amount of intermittent generation increases. For example, it has been suggested that around 6% of the potential UK CO_2 savings could be offset if around 25% of the country's electricity is provided by wind in 2020 (HP, 2014).

Wagman (2013) appears to disagree somewhat, suggesting that, in the 20 states in the USA that have the highest wind capacity, the average efficiency of coal-fired plants declined by only 1% (basis not specified) between 2005 and 2010 compared with 2.65% in the other 30 states. Similarly, coal plant efficiency fell by 1% in the top wind capacity countries in Europe and remained unchanged across all OECD Europe countries between 1999 and 2010.

Wagman (2013) also argues that there is a correlation between increasing wind energy and declining emissions. He argues that if wind energy were causing large declines in the efficiency of fossil-fired power plants, zero or negative correlations between emissions and wind would have been found instead of correlations approaching 1 in countries such as Germany (0.86), Spain (0.90) and Ireland (0.96). To some extent this may not so much prove the lack of a negative effect from increased flexibility of coal units but rather demonstrate the effectiveness of emissions control technologies and the experience of coal-fired operators to keep emissions under control.

Any decrease in plant efficiency means more coal burned for less power which could mean more emissions of particulates. However, current particulate control systems achieve such high control efficiencies that there is little or no risk of exceeding emission limits at any time. According to Henderson (2014), particulate control systems can cope with partial load and rapid load changes without issue. However, gas temperature changes can affect conditions in the flue gas such that there is increased condensation on particles, which can affect both fabric filter and ESP performance. Intelligent control systems can be installed to reduce the effect and also to reduce the energy consumption of particulate control devices during low load periods.

Since flue gas desulphurisation (FGD) systems for SO_2 emission control operate based on precise reaction conditions, including temperature and water flow, fluctuating plant operation can affect SO_2 emissions. This can be particularly important during start-up and shut-down periods. Compliance with emission limits during these periods and during periods of rapid load changes can be an issue which requires sophisticated control concepts and changes in FGD operation (Henderson, 2014). According to Hesler (2011), start-ups of FGD systems should be minimised for several reasons:

- to reduce the need to purge systems to avoid slurry solidification;
- to reduce the impact of fuel oil residues on linings and fabric filters;
- to reduce the requirement for lengthy warm-up times.

Wagman (2013) suggests that the efficiency of modern scrubber systems and the expertise of those running them means that SO_2 emissions can be controlled effectively during ramping and cycling. He notes that analysis of 'hundreds' of coal-fired units suggests that SO_2 limits are seldom exceeded and only for brief periods during start-up or ramping. Danneman (2016) agrees that exceedances of SO_2 limits due to increased plant cycling is uncommon.

Emissions of NOx can increase by up to around 10% at some plants during periods of start-up due to increased fuel use at these times (Cochran and others, 2013). Changes in temperature will affect selective catalytic reduction system (SCR) operation for NOx control, especially in systems which use ammonia. This may mean greater ammonium slip and, as a result, more potential damage from corrosion in downstream areas. ABS (ammonium bisulphate) is formed from ammonia in SCR systems during periods of low temperatures. ABS is a sticky liquid which can fill catalyst pores and reduce the effective reactive surface area (Hesler, 2011). Economiser bypass systems can be established to reduce this effect. Alternatively, changes in temperature can be controlled through the use of static mixers (baffles) or the installation of heating facilities (Henderson, 2014).

Wagman (2013) suggests that, although NOx emissions are harder to control than SO_2 during flexible operation, any resulting increase in emissions is 'minor'. In fact, Wagman goes on to suggest that NOx emissions are actually lower (up to around 14%) during part load operation and that most emission rates changed by less than 2%. Danneman (2016) notes that any increase in emissions of pollutants such as SO_2, NOx and even mercury during changes in plant operation are minimal and can be controlled through best practice.

Whilst these emissions arise from the coal fired units being operated to ensure energy capacity is met, the Massachusetts Institute of Technology (MIT) has published a report which suggests that some of the responsibility for these increases in emissions must ultimately lie with the renewable energy sources which force such situations to arise (MIT, 2011).

2.4 Comments

In order to ensure supply matches demand for electricity within a grid, operators will look for the most cost effective means of increasing or decreasing the input from various utilities. Many regional grid systems now require that priority be given to renewable technologies, which have fluctuating output, leaving less flexible plants, such as older coal units, to make up the difference. However, in order to keep this ramping up and down of coal plants to a minimum, grid operators will maximise the potential to store energy or to take advantage of any available system inertia. Not only will this keep costs down, it will also reduce the requirement of coal plants to run in a non-baseload manner which can lead to inefficient operation and, possibly, changes in the balance of pollutant emissions to air.

3 The costs of managing intermittency

Intermittent renewable energy systems such as wind and solar are known as variable renewable energy sources (VRE, also known as renewables energy systems, RES). That is not to say that fluctuations in demand don't occur with other energy sources – they do, and methods have been established to manage this fluctuation through cooperation from dispatchable power sources. It is important to note that, for the moment, the increased renewables capacity is not entirely replacing fossil fuels. Because of the intermittency of VREs, back-up capacity is still required. Although it has been suggested that 100% back-up capacity is necessary, this is not the case. Back-up capacity requirements vary depending on several factors including the consistency of weather in different areas. Danneman (2016) suggests that diversifying wind farm locations can help generate power as wind fronts move, often predictably, through regions.

Determining the additional costs incurred by coal-fired plants as a result of intermittency is not easy and, although there is published material on levelised costs and plant running costs, and potential damage and repair costs, there does not seem to be a standardised method of determining the total cost to a coal utility of providing services to help the grid cope with intermittency. For the most part, this is because the costs will vary on a plant by plant basis depending on the difference in plant use, change in running and fuel costs, operation and maintenance adjustments and potential changes in revenue from switching from baseload to ramping operation. There are other costs to be considered, including grid effects and the overall cost of supplying electricity to the consumer. These costs are significantly affected by intermittent and variable renewable systems. This Chapter looks briefly at the economics of prioritising and funding different energy systems, then at grid charges and then finally focuses on levelised costs.

3.1 Prioritisation and funding

In a level market place with no political influence, electricity would be produced by the cheapest means possible and, for most regions, this would be from thermal systems including coal. However, as mentioned in Chapter 2, policy is changing to prioritise the use of cleanest technologies first, despite the fact that these cleaner technologies may not be the most cost-effective options. Market mechanisms exist to promote the use of these cleaner technologies (such as carbon credits, guaranteed sales and favourable feed-in tariffs) which means that a premium price is paid for this cleaner energy. Renewable technologies may receive tax subsidies, direct subsidies, purchase obligations, and long-term contracting requirements which make them more affordable and more profitable than they would be on a stand-alone basis. But since there is insufficient clean energy to meet total electricity demand, the remainder is made up of the available fuel mix in the region. In some cases, there is no regard for how clean or efficient these load following options are which means that they are selected largely on availability and cost (lowest cost first). This prioritises clean energy at the top of the dispatch pile but can leave much of the remainder working in less than ideal conditions.

Some older units, working in an increasingly flexible manner to fill the gap in electricity demand, will be operating at much lower profit margin than previously and are therefore less likely to have funding available for potential investment in plant improvements and upgrades. It is beyond the scope of this report to review the funding or investment profiles of different energy generating technologies. But it is important to be aware that funding has a significant effect on the cost of electricity and of investment in existing and new technologies. The disparity of funding between technologies and regions is the subject of many papers and heated debates. For example, Darwall (2015) produced a paper for the UK Centre for Policy Studies entitled 'How renewables subsidies destroyed the UK electricity market'. The paper argues that target driven policy objectives (such as 50% renewables by 2020) are inflexible and override the economics of fair trade which leads to an unstable marketplace. He states that any policy framework to encourage renewables that systematically conceals their true costs will result in higher costs and higher electricity bills for the same quantum of renewable capacity. Darwall (2015) suggests that the UK's renewable policy will result in a near trebling of grid costs. Several papers have been written in response to denounce Darwall's paper, arguing that it is based on incorrect values and calculations (Ottery, 2015; *see* also Chapter 5).

According to the IEA report on the projected costs of generating electricity (IEA, 2015b), regulators the world over are reviewing capacity remuneration mechanisms as well as working towards better performing flexibility and adjustment markets. Where flexibility and capacity are lacking, regulators must create new revenue streams for providers of these services. The levelised cost of energy (discussed more later in this chapter) compares costs over the lifetime of plant operations. However, the IEA report suggests that four additional metrics would give a better understanding of the performance of both dispatchable and non-dispatchable markets:

- **Capacity credit** – a measure of the extent to which a plant's capacity is actually available when needed, such as at peak demand.
- **Cost of new entry** – the levelised cost of capacity at fixed costs. The ability to provide capacity alone at low cost, almost independent of variable cost, is a necessary complement to variable renewables production in liberalised markets.
- **Flexibility metric** – to measure the ability of a technology to change its output or load at short notice.
- **Value factor** – quantifying the market value of deploying variable renewables in different electricity systems, specific to each power system.

Although this report does not look at the discrepancies in funding of renewables versus coal, it is important to note that the tipping of the balance towards greater financial security from wind investments has a negative effect on coal investment – on both new plants and existing units. As coal falls out of favour, operators will find it more of a challenge to obtain funding for further investment in either upgrading or replacing older units and may find it easier to continue to run older, less efficient units for as long as economically feasible before closure. Whilst this does, theoretically, avoid new coal build, it does extend the life, and the associated emissions, from older, less efficient units.

3.2 Costs of electricity production

This report does not consider electricity prices in detail. However, it is important to note that the profitability and thus feasibility of any power source is highly dependent on the profit made from selling energy to the grid. Non-dispatchable technologies such as renewables provide energy to the grid but do not provide sufficiently reliable energy to be considered as capacity – they cannot be relied upon to meet demand. Because of this, it has been argued by some analysis that renewables should pay a capacity charge back to the system to cover the cost of building and operating the back-up technology required when intermittent technology is unavailable (IER, 2012). Without this, the additional cost of providing flexible power falls on thermal units such as coal-fired plants. According to Kemp (2013) "*the actual costs of using baseload plants to follow load are poorly understood, but are likely to be substantial*".

It has been suggested that, in the UK at least, intermittency will add 1 pence/kWh to the cost of renewables when their share of total electricity rises to 24% in 2020. Currently the cost of generating a unit of electricity from onshore wind is around 7.5–11.5 pence/KWh. According to a UK study, intermittency is increasing the cost of onshore wind by 8–21%. For solar the additional cost may be two to four times higher than that for wind (HP, 2014).

As mentioned in Section 3.1, in some countries, energy tariffs are structured such that renewable energy sources are guaranteed sale of their output to the grid whereas sources such as coal-plants are now being relegated to only being required to make up the difference when energy is in short supply. In these situations, it is not uncommon for thermal plants to have to bid to provide this shortfall in energy and therefore plants which offer to sell energy at the lowest price will make the most sales. However, there is a balance to be made between sales which produce little or no profit but guarantee plant operation and sales which occur less often but which provide greater income per megawatt hour. The choice between the two options is not necessarily simple and will depend on the flexibility of the plant in question.

Figure 7 shows the changes in pricing as plants move from operating in different modes. Those operating at baseload do so for consistent and long periods, being paid an average amount which, arguably, will allow them to budget accurately over extended periods of time. Mid-merit plants will be expected to increase and decrease (ramp up and down) their output in a semi-steady manner, making a greater profit the longer they run. There will be a balance between those periods when they run with a lower income rate and those periods when the income is higher. For peaking plants, providing power only in periods of significantly increased demand (or when output from other sources has dropped for whatever reason), the income in terms of electricity price is potentially high but profit will only be achieved if there are enough peaking periods for money to be made. As shown in the bottom graph of Figure 7, the number of peaking operation hours available are significantly smaller than the number of baseload operation hours.

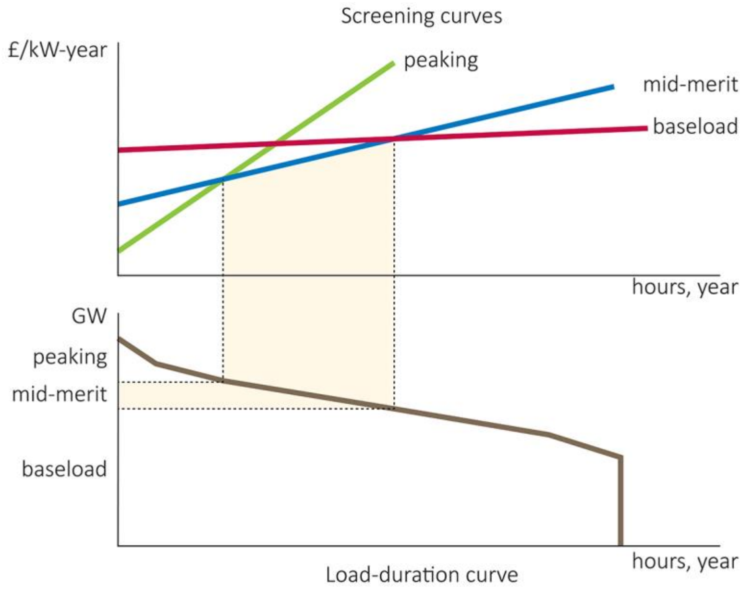

Figure 7 The derivation of optimal capacity (Green and Vasilakos, 2010)

As emphasised by Green and Vasilakos (2010), once wind power forms a significant part of an electricity market, this will feed through to short-run price volatility – prices will be lower when wind generation is high and higher when the wind is low. And so Green and Vasilakos point out that, although wind capacity has been added to a number of European markets, the amount of conventional capacity has not changed significantly. An increase in capacity will, however, generally lead to a reduction in the margin between price and variable cost. It is suggested that the increased capacity in Germany has led to the decline of wholesale prices and that this has offset the cost of subsidising wind (*see* Chapter 5). This means that the subsidies have effectively been paid by the conventional generating companies (the thermal plants) rather than the electricity consumers. The same effect has been reported for Spain. In the UK, it is expected that the rise in wind capacity will mean that a higher proportion of the conventional, thermal, stations will be expected to operate at low load factors and will be largely called upon only when the wind is below average. This means that in countries considering both renewable and conventional energy options, new plants with low capital costs may be favoured over those with low operating costs, compared to the opposite situation in the past. This also means that this thermal capacity will require higher prices during those periods to recover fixed costs from an energy-only market, such as that in the UK and most of the EU.

3.3 Changes to the grid

Although not a direct cost to coal plant operators, the performance of the electricity grid is of paramount importance to whether or not a new plant, especially an intermittent one, will be able to provide useful energy. Coal-fired plants are commonly built in areas which either have potential access to the power grid or where access can be provided in an affordable manner. Providing electricity to remote regions requires extension of an existing grid to take power out to locations further afield. For example, new grids are required to bring power in from offshore wind farms. But the expansion of older grids also puts additional strain on systems which were designed several decades ago, which are aging, and which are not designed for significantly expanded capacity. This can apply to small local networks but also to larger national grids and grids which interconnect several countries within a continent. Grid infrastructure varies with age, geography, budget and design requirements. Germany is required to upgrade around 400 km of existing grid and to add 850 km of new grid to accommodate the expansion needed to attain their goal of >20% renewable energy by 2020 (Mills, 2011). According to Krishnaswamy (2015) global utilities are collectively spending around $25 billion per year on modernising and expanding electricity networks to support the addition of their renewable portfolio.

Too much power to the grid can be as bad as too little. Countries such as the UK, India, Italy and parts of the USA have had to shut down windfarms during periods when too much power was being produced simultaneously and there was a temporary overload of the power lines. Italy lost 500 GWh of wind production from this problem in 2009 alone (Brook, 2013).

Variable electricity production causes cost penalties due to 'system effects', including intermittent electricity access, network congestion, instability, environmental impacts and problems with security of supply. Brook (2013) reports that renewables such as wind and solar generate system effects which are at least an order of magnitude greater than for dispatchable technologies. And so there are grid level costs which arise directly as a result of the growth of renewable energy. These require extra investment to extend and reinforce the grid, including costs for increased short-term balancing and for maintaining the long-term adequacy of electricity supply. Brook (2013) presents recent work by the OECD which assesses the grid level system costs for six OECD countries with contrasting mixes of electricity technologies: Finland, France, Germany, South Korea, the UK and the USA. System costs were calculated for 10% and 30% penetration levels of the different generating sources available, based on short-term balancing, long-term adequacy and the costs of various grid infrastructures. The results indicated that, for coal, the system costs of 10% and 30% penetration were similar at between 0.5 and 0.9 $/MWh. For solar the costs were an order of magnitude higher, at up to 57.9 $/MWh at 10% penetration to 83 $/MWh for 30%. Wind (onshore) could be as much as 36 $/MWh at 10% penetration and 43.9 $/MWh at 30%. Brooke concludes that these costs can therefore be significant and should be included in any realistic analysis of the total system costs of any technology in a national electricity market. Brook simplifies this in Figure 8 which shows the total system cost for different electricity generation systems. Taking potential carbon costs into account means that nuclear, coal and gas are pretty much even in terms of cost. However, renewable technologies are still more expensive and the cost of grid-level effects, shown in red, is a significant portion of this extra cost.

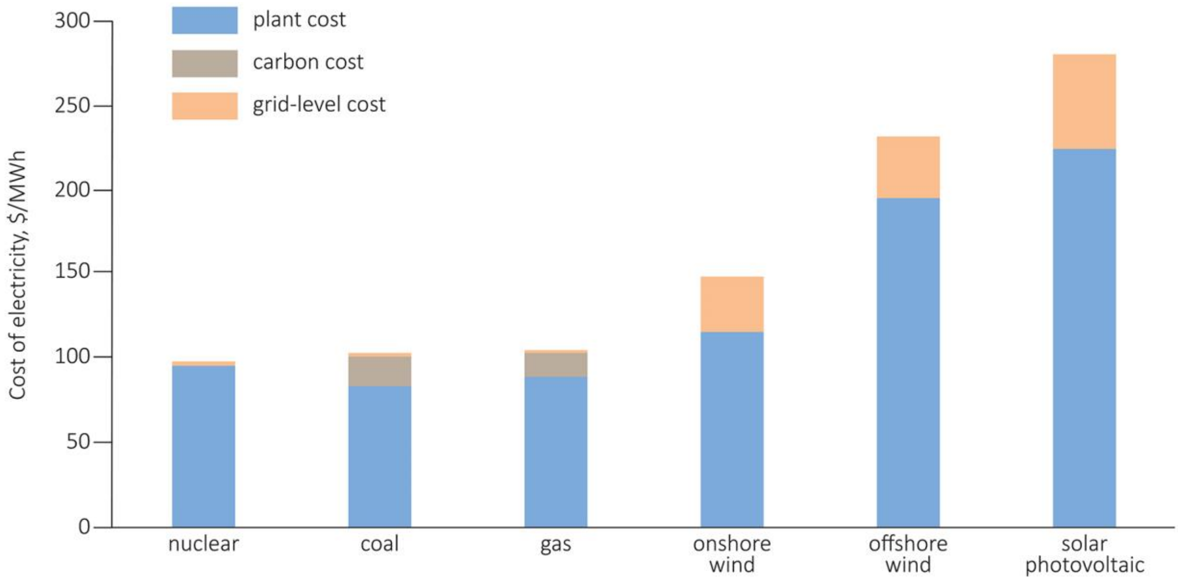

Figure 8 Total system cost for generation technology (2012) including carbon and grid-level costs (Brook, 2013)

Brook (2013) suggests that, like carbon prices, grid prices should be internalised – the plant owner should have to pay for grid level costs. This would help to level the playing field with dispatchable technologies.

The review by MIT (2011) looks at the different kinds of costs for integrating intermittency into the grid. These include:

- **Existing asset costs** – the costs to existing plants in terms of needing to cycle and ramp. This is similar to the idea of 'stranded assets' where utilities may be left with long-term contracts (including fuel and transport contracts) that are no longer economically viable.
- **Direct integration costs** – transmission interconnection/upgrade costs and increased regulatory services. Ideally the additional new costs would be allocated to the new renewable sources at a higher rate than to existing thermal utilities but this is determined by the local authority or regulator.
- **System infrastructure costs** – for upgrading to maintain market operations and system reliability, including more complex scheduling frameworks and capabilities for forecasting the system net load.

As the MIT (2011) report notes, the allocation of these new costs has to be carefully considered in terms of fairness. To do this there are questions to be raised with respect to reliability of the new intermittent sources, the market capacity and potential effects on investments, and the identification of beneficiaries as a lack of clarity could constrain investment.

3.4 Levelised costs

Comparing the cost of electricity from different sources is not easy as there are so many variables to be taken into account. For example, electricity production costs do not represent actual costs in a fair manner as the cost of building a nuclear plant can be significantly higher than building a coal or gas plant.

The cost of producing electricity includes several different inputs, some of which are harder to calculate or estimate than others. In general, electricity production costs include (IER, 2012):

- **Capital costs** – for building of the plant and establishment of related services.
- **Financing charges** – repayment of loans.
- **Production/operating costs** – including fuel costs as well as maintenance costs through the lifetime of the plant.

Like mortgages on houses, capital costs for power plants are commonly paid off within 20–30 years, after which the costs are simply those for production and operation. Plant-specific costs include regional labour costs as well as transport costs relative to the distance from transmission lines and fuel sources.

To deal with these different factors, costs for electricity generation are often calculated as 'levelised costs of energy' (LCOE). LCOE represent the total cost of the plant, from construction through operation for its lifetime, including capital and financing charges, converted to equal annual payments over the lifetime of the plant, based on an assumed lifetime and an assumed duty cycle. Over the lifetime of a plant, operation becomes more cost effective after initial debts are cleared. It can therefore be argued that, since many plants are being run for longer than originally planned and, more commonly, in a different way to their original design (with retrofits and more sporadic operation), the levelised cost values given at the beginning of a plant life will be very different from the actual levelised cost upon its closure.

Because of the different lifetimes and operation of fossil fuel plants and renewables, the levelised costs of each are not considered directly comparable. This is largely because renewables are far more sporadic in their output, depending on the weather but also on their use, as defined by the operator. As discussed in Chapter 2, non-dispatchable technologies such as renewables supply energy but not capacity since they cannot be counted upon to continually meet demand (EIR, 2012).

The IEA (International Energy Agency, 2010) has calculated the projected costs of generating electricity for plants commissioned in 2015 in different regions, based on levelised costs (real discount rates of 5% and 10%), taking fuel prices and, for the first time, a carbon price of 30 \$/t of CO_2 into consideration. The report suggests that, even with this carbon cost included, coal will remain competitive with gas and onshore wind in some parts of Europe and North America. However, at the 10% discount range, onshore wind becomes far more competitive than all other energy options in Europe beyond 2015. The highest variables within the calculations related to local markets and finances, as well as CO_2 and fuel prices. The lower the cost of financing, the better the performance of capital-intensive, low carbon technologies such as wind. Notably the IEA concluded that there was no technology that had a clear overall advantage globally or even regionally.

Figure 9 shows the estimated LCOE of new electricity generating technologies in 2017. These data were estimated in 2012 based on 2010 \$/MWh values in the USA and are included here to give an indication of the difference in costs for different electricity types. From Figure 9 it is evident that intermittent energy sources remain significantly more expensive in terms of levelised cost than more standard forms of energy.

Gas is cheaper, although this varies regionally with local gas costs. Coal costs are also relatively low overall. For all the sources other than gas, fixed operation and maintenance are the largest cost factors. For coal, operation and maintenance is the next largest cost factor at around one third of the levelised cost whereas for the renewable sources, this is much lower.

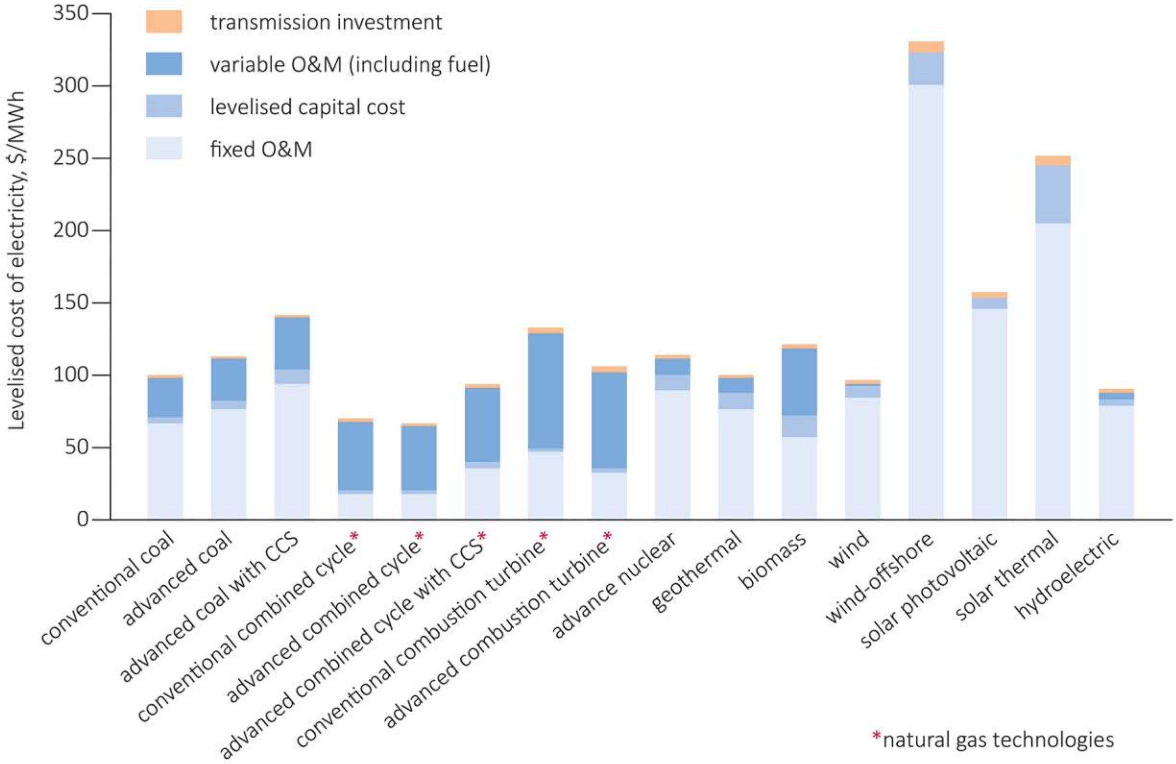

Figure 9 Estimated levelised cost of new electric generating technologies in 2017 (2010 $/MWh) (IER, 2012)

The values in the above graph do not include subsidies or tax credits (IER, 2012; *see* Section 3.1). It is these funds which make renewable energy more 'affordable' to the grid.

It has been reported that the levelised cost of wind production would be lower than the levelised cost of coal and nuclear in the US by 2020. However, Joskow (2011) argues that using levelised cost to compare the attractiveness of different technologies in this manner is flawed. Joskow argues that a direct comparison of levelised costs suggests that the electricity generated is a homogenous product governed by the law of one price. This does not take into account the fact that electricity costs (wholesale market prices) vary widely over the duration of a year and the difference in cost can be up to four orders of magnitude. Such high prices occur during critical peak hours. Although this may happen for less than 1% of the total time during the year, these periods and costs are still important. Joskow (2011) suggests that generating units which cannot supply electricity during these critical periods should be at an economic disadvantage. These output and electricity price fluctuations are not captured in the levelised cost calculations. A dispatchable and a non-dispatchable plant may have similar levelised costs per MWh whilst having very different net economic values and profitability (*see* Section 3.2). Electricity bidding frameworks which select suppliers based on lowest cost may actually undervalue solar (produced during the day when prices are high) and overvalue wind (which is usually produced during off-peak periods).

Joskow (2011) presents numerical examples based on the operation of dispatchable and intermittent technologies during two basic demand periods:

- Peak: 3000 h/y, prices sit at 90 $/MWh
- Off-peak: 5760 h/y, demand is 50% of that in the peak period, prices sit at 40 $/MWh.

The dispatchable and intermittent technologies are not defined, but simply quantified in terms of cost, as shown in Table 3.

Table 3 Hypothetical levelised cost calculations (Joskow, 2011)

	Dispatchable	Intermittent
Construction and fixed O&M cost ($/MW/y)	300,000	150,000
Operating cost ($/MWh)	20h	0
Capacity factor, %	90	30
MWh/MW/y	7,884	2,628
Levelised cost ($/MWh)	58.1	57.1

The comparison has been set up such that the levelised costs are virtually the same so that plants can be considered competitive based on this and other factors can be analysed separately. The dispatchable technology is twice as expensive in terms of construction and maintenance as the intermittent technology and the former has operating costs which do not apply to the latter. However, the dispatchable technology is available to generate power 90% of the time whereas the intermittent technology only has a capacity factor of 30%. Outages are assumed to reduce the actual production of the dispatchable technology to 7884 hours although it is assumed that all these outages are taken during off-peak hours. The dispatchable technology has an actual on-peak power production time of 2628 hours during the operating year.

Table 4 shows the economic value of each of the technologies. For the dispatchable technology the situation is relatively simple – the plant earns enough revenue to cover all costs plus produces a small profit. For the dispatchable plant, the outcome depends very much on the actual circumstances.

Table 4 Economic value of dispatchable and intermittent generating technologies (Joskow, 2011)

	Dispatchable all cases	Intermittent Case 1	Intermittent Case 2	Intermittent Case 3
Peak period, MWh supplied	3,000	0	50	2,628
Off-peak period, MWh supplied	4,884	2,628	2,578	0
Revenues, $/MW/y	465,360	105,120	107,620	236,520
Total cost, $/MW/y	457,680	150,000	150,000	150,000
Profit, $/MW/y	7,680	-44,800	-42,380	86,520

The table shows the outcome of three different off-peak scenarios, which can be explained as follows:

- **Case 1 –** Windy at night (off peak) but too calm during the day (peak) to produce power. Power is only produced during off-peak periods and only for 2628 of the 5760 off-peak hours. This indicates a 100% off-peak production rate which is an extreme assumption but still achievable. Under these circumstances the wind plant does not cover its costs and loses $44,880. This is despite having the same levelised cost as the dispatchable plant, as shown in Table 3.
- **Case 2 –** The intermittent plant runs for 50 hours during the peak period and 2578 during the off-peak period. Although this means increased revenues it is not enough to cover the generator's costs.
- **Case 3 –** An extreme assumption where all of the electricity produced by the intermittent plants is produced during the peak period. This would be more plausible for a solar wind farm than a wind turbine. This is why, although solar technology may actually have a higher levelised cost than wind, it has the potential to produce more valuable electricity and make significant profits.

Joskow (2011) argues that this approach to calculating merit based on the expected market value of the electricity produced, total life-cycle costs and expected profitability would give a better indication of actual costs than the levelised cost alone.

Lazard (2014) produced LCOEs for various technologies on a $/kWh basis including the implied cost of carbon abatement. The study looks at the changes in costs with fuel prices and levels of subsidy. The results are rather detailed and so the interested reader is referred to the original document for further information on both the techniques and comparisons. However, a summary of results is shown in Table 5.

Table 5 Comparison of different levelised costs of energy in the USA, $/MWh (Lazard, 2014)

	Coal	Nuclear	Biomass	Solar PV rooftop, residential	Solar PV utility scale
Unsubsidised LCOE, $	66–151	92–132	87–116	180–265	60–86
Subsidised LCOE, $	66–151	92–132	67–100	138–203	46–66
Range reflecting sensitivity to fuel prices, $	61–158	90–134	83–125	180–265	60–86
Capital costs, $/kWh	3000–8400	5385–7591	3000–4000	3500–4500	1250–1750

A few general conclusions can be drawn from Table 5:

- The various LCOE have relatively wide ranges to take into account variables such as fuel cost, local considerations and so on.
- Coal and nuclear only benefit from subsidies in some regions whereas biomass and solar more often than not become more affordable as a result of subsidies.
- Solar shows no variation in fuel cost effects whereas these can be somewhat important for coal, biomass and, to a lesser extent, nuclear.

- Capital costs vary significantly due to the range of technologies available and also due to local variations. However, capital costs can be significantly lower for biomass and solar than for coal and nuclear plants.

3.5 Comments

Prior to renewables commitments, a coal-fired utility would aim to have enough capacity available to provide a consistent amount of energy to the grid, as agreed in advance with the grid operators. Most regions comprised a core of baseload plants, ramping up and down in a relatively controlled manner to lower or increase power as required during low demand or peaking periods. Providing baseload capacity provided a consistent income which was used to cover the capital and operating costs of the plant in a relatively easy to calculate manner. The greatest amount of profit could be made in the shortest period by providing peaking capacity – the actual profit being dependent upon the amount of hours run or the 'in-market availability', the amount of time a unit is available to provide power during peak hours.

As coal plants move towards providing lower and more intermittent levels of peaking and mid-merit power, the balance of plant profitability becomes tighter. Plant operators must bid low to win the option to provide power during more irregular and shorter periods of time. And so operators bringing new plants online into a grid with significant renewables available face far greater challenges for recovering capital and operating costs than in the past. As discussed in Chapter 4, the changes in plant operation put strain on the plant itself which can also add to increased costs and reduced income.

4 Changing plant operating mode

This chapter reviews the different ways in which flexible operation can incur costs, firstly looking at how gross changes can be made in plant operation to offer flexible output and then moving on to the costs associated with any changes in equipment or operational practice. Possible costs due to increased maintenance and damage are then covered. Finally, options for minimising the effects through changes in plant management practices are considered.

As discussed in Chapter 3, older coal-fired plants were designed to run mainly at baseload. Newer plants tend to be built with more flexibility. The cost of making changes to plant operation to adjust output will therefore vary on a plant by plant basis. In a previous report by CCC, Mills (2011) noted that new, flexible design plants will be expected to cycle from their first day of operation, making capital cost recovery slower. More flexible plants are also more advanced and so inherently more expensive. But for all coal-fired units, there are additional costs from flexible operation in terms of fuel costs and additional wear and tear.

Upgrading of existing units to increase their flexibility is discussed in detail in the CCC report by Henderson (2014). Upgrading changes a less flexible unit into a more flexible one, representing a large one-off cost to save future costs. Costs for upgrading individual plant components can be significant but will be extremely plant specific, depending on the current state of the unit. The decision on how much to spend will also be affected by the projected lifetime of the plant and the expected additional revenue from increased flexibility. In addition, costs for upgrading and changes in operation cannot easily be extrapolated to other plants due to variations in age, design and history of operation. This chapter looks more at smaller changes to plants to increase flexibility without major structural or configurational changes.

One of the key findings of a 2011 MIT report was that achieving economic flexible operation of a coal plant requires a detailed understanding by the owner of component-level impacts on operation and costs. It was suggested that plant owners are likely to continue to operate existing, older units with minimal upgrades as this is cheaper in the short term than undergoing equipment retrofits to improve plant flexibility. Financial incentives may therefore be required to ensure investment in flexible generation (MIT, 2011).

The main impacts of a flexible generating regime on a coal-fired plant are summarised in Figure 10. This also includes other external influences forcing the intermittent generation (gas price and demand changes).

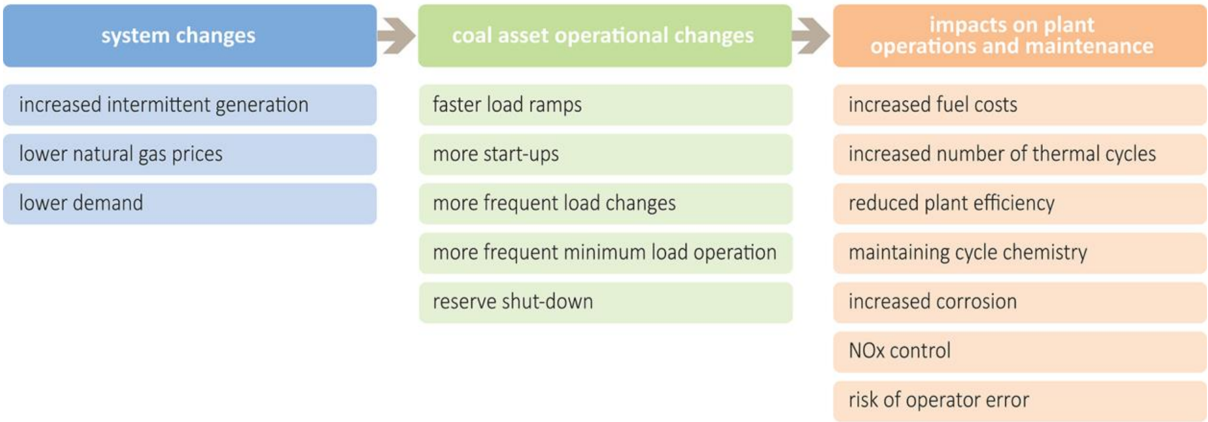

Figure 10 Impacts of intermittent renewables on coal-fired power plants (MIT, 2011)

The major impacts included in Figure 10 are discussed in more details in the sections to follow.

4.1 Changing plant operating mode

In order to evaluate the potential costs, it is necessary to understand the different options for changing output. Looking more specifically at the cycling variations for coal units, Hesler (2011) listed several options for altering plant operation. These included increased load and thermal ramp rates (changes to plant operation to allow greater loads and faster heating); high unit turndown during low demand (switching to deep cycle operation where the plant runs at the minimum safe load, including lower minimum load operation); frequent unit starts (hot, warm and cold) and reserve shut-down; and long-term plant lay-up (idling or switching off completely). For flexible operation, the most important factors, for a reliable and available unit, are (MIT, 2011):

- partial load efficiency;
- fast ramping capacity;
- short start-up times.

Modern coal plants can be designed to provide rapid output changes over a limited range of 5% and even up to 10% within 30 seconds when designed to provide primary frequency control on the grid. In addition to these short response times in some plants, other plants are designated to operate to provide secondary (within several minutes) frequency control. These plants will take over the output, freeing up the primary response plants to ensure they are ready should further immediate response be required. Coal-plants which are used in this manner for frequency control are kept running, and so synchronised, but operating below full load (known as 'spinning reserve'), ready to provide additional capacity when required. For example, three plants in Italy (3 x 660 MW ultra-supercritical, USC, units built between 2009 and 2010) have the capacity to produce a 4% change in power within 30 seconds. The response time of the boilers is around 90 seconds which allows the primary reserve from the turbine system to be recovered quickly for 15 minutes, as required by the grid (Henderson, 2014). These, however, are USC plants – built quite recently and with high efficiency output – and so are suited to such flexible performance, unlike older units. The report by Henderson (2014) compares the flexibility capabilities of current state of the art plants and plants under development. Start-up times are being reduced from 2–6 hours down to 1–4 hours, minimum loads are being reduced from 40% down to 25% and even lower, if indirect firing is used. Primary frequency control times are being improved from 2–5% within 30 seconds to 10% within 10 seconds. Plants are being designed and built to provide more flexible output to be of more use in a grid system where intermittency issues are likely to increase. These plants are significantly more expensive than standard subcritical systems.

Coal plants can generally ramp up output at 1.5–5% per minute. However, as ramp rates increase, expected maintenance costs also increase as the system is put under undue pressure (MIT, 2011). Table 6 shows the ramp rate of coal plants as compared to other power generating technologies.

Table 6 Capability of different power generating technologies to provide flexibility (IEA, 2015b)

Plant type	Start-up time	Max change in 30 s, %	Max ramp rate, %/min
Open-cycle gas turbine	10–20 min	20–30	20
Combined cycle gas turbine	30–60 min	10–20	5–10
Coal plant	1–10 hours	5–10	1–5
Nuclear power plant	2 hours – 2 days	<5	1–5

Coal fired power plants in general take longer than gas plants to ramp up and down but are much faster to start than nuclear plants. Older plants tend to be used for fast ramp-up situations. This is because, although they were not designed for flexible operation, they tend to be smaller capacity units and, perhaps most importantly, they have already recovered their capital costs and are therefore cheaper to run (MIT, 2011).

Figure 11 shows the load ramping for a typical coal-fired unit with six coal mills, two of which are required to maintain stable furnace combustion and minimum load and all six required for full load.

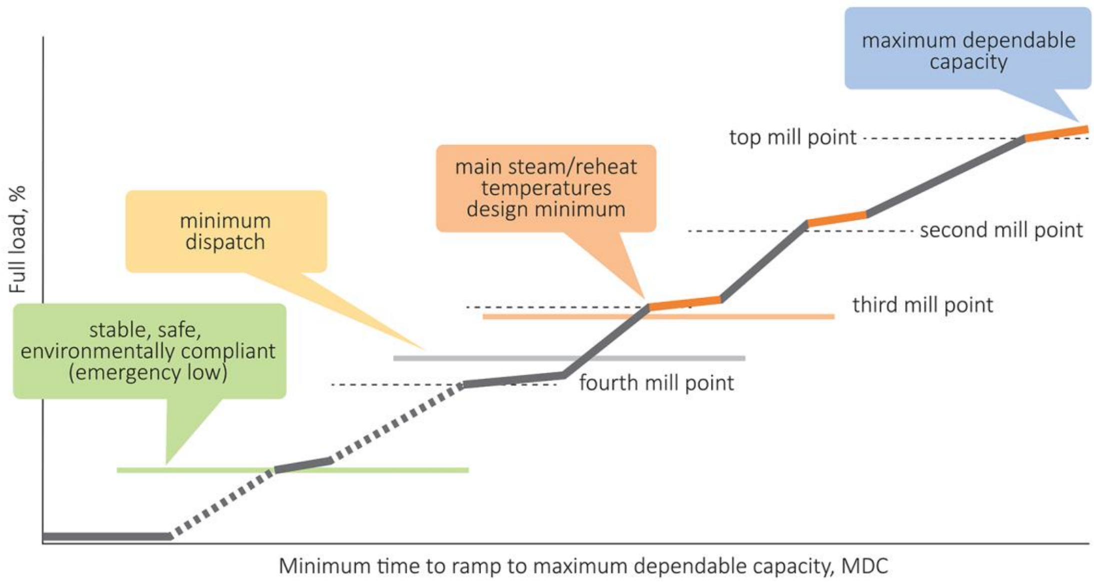

Figure 11 Load ramp cycle for a six-unit coal plant (Danneman and Lefton, 2009)

The graph indicates the point (lower, in green) where the plant is running at the lowest point which is considered safe and compliant, involving two mills. More mills are required to provide minimum dispatch output and all mills are required to provide the maximum dependable capacity. There is a lag period between each break point in the graph indicating the time taken to bring each mill on line.

Hesler (2011) notes that most plants will actually be able to start-up in less than half the time specified by baseline load procedures. Large machines can be synchronised within 35–50 minutes and full load (500 MW) can be achieved within 60 minutes. Temperature transients can be 'calmed' during changes in operation by introducing systems such as off-load circulating systems which pump water slowly around the evaporative sections to balance the temperature variations.

Interestingly, Danneman (2016) notes that wind farms are being designed to be more flexible. This requires some wind to be 'spilled' but, as wind capacity increases, it will become possible in future to keep some spinning reserve in the form of wind farms, reducing the pressure on fossil plants to produce power within short time periods.

4.2 Cost penalties of flexible operation

There are two main types of coal plant cycling to facilitate changes in output, as mentioned in Section 4.1 (Connolly and others, 2011):

- **On/off cycle – the shutting down and restart of a unit**. – this need not actually involve turning the plant off completely. The cycles can be further divided into hot, warm and cold starts, depending on how long the unit is offline and the loss of heat during this period. For a hot cycle, the unit is offline for less than 24 hours, for warm the timing is 24–120 hours and a cold cycle occurs over 120 hours after shut down. This, of course, may vary from unit to unit depending on design.
- **Load follow cycl**e – the increasing and decreasing of generation between maximum and minimum output. Load following can be in either shallow or deep cycles. A shallow load follow reduces generation to the economic minimum level – the lowest level of net production that a generating unit can maintain continuously under normal system conditions. A deep load follow reduces generation to the emergency minimum level or to the lowest theoretical minimum level of operation where the unit is safe, stable and environmentally compliant.

Connolly and others (2011) provide a summary of ways to estimate cycling costs, although these vary on a plant-by-plant and case-by-case basis. Hot start costs are reported to be in the range of tens of thousands of dollars, proportional to the size of the unit – the larger the unit, the higher the start-up costs. Connolly and others (2011) also give the example of shutting off a 100 MW minimum coal unit. This would reduce the system minimum generation by 100 MW at a cost of over $50,000 for a cold start.

Lefton and Besumer (2006) give different values for hot and cold start conditions than those mentioned above. Hot starts include temperatures of 370–480°C (700–900°F) within 8–12 hours of being offline. This temperature refers to the steam turbines first stage, a critical parameter used to determine how fast a steam turbine can be loaded (Danneman, 2016). Warm starts 121–480°C (250–700°F) occur after

12–48 hours and cold starts (ambient temperature) after 48–120 hours offline. Lefton and Besumer (2006) advise that the definitions vary due to unit size, manufacturer and system operator.

More recently, Lefton and Hilleman (2011) have collated data from around 300 plants in the EU and North America and have thus managed to identify ranges of costs, noting that the actual cost of cycling a coal plant are often higher than expected. Table 7 shows a summary of the values collected during the extensive study.

Table 7 Typical costs for a 500 MW coal-fired power plant, in 2008 $ (Lefton and Hilleman, 2011)

Type of transient	Cost category	Cost estimates (1000 $)		
		Expected	Low	High
Hot start, 1–23 h offline	Maintenance and capital	53.2	42.6	67.4
	Forced outage	25.1	20.1	31.7
	Start-up fuel	8.5	5.9	12.7
	Auxiliary power	4.4	3.5	5.5
	Efficiency loss from low and variable load operation	2.1	1.7	3.4
	Water chemistry cost and support	0.6	0.5	0.7
	Total cycling cost	93.9	74.3	121.4
Warm start, 24–120 h offline	Maintenance and capital	57.0	45.3	71.0
	Forced outage	26.9	21.3	33.4
	Start-up fuel	17.8	12.5	23.7
	Auxiliary power	9.4	7.5	11.7
	Efficiency loss from low and variable load operation	2.3	1.9	3.8
	Water chemistry cost and support	2.3	1.8	3.8
	Total cycling cost	115.7	90.3	146.5
Cold start, >120 h offline	Maintenance and capital	85.4	67.7	106.2
	Forced outage	40.2	31.9	50.0
	Start-up fuel	26.8	18.8	10.2
	Auxiliary power	12.0	9.6	15.0
	Efficiency loss from low and variable load operation	2.6	2.1	4.1
	Water chemistry cost and support	6.9	5.5	8.6
	Total cycling cost	173.9	135.6	194.1
Load follow down to 180 MW	Maintenance and capital	8.2	4.8	12.9
	Forced outage	3.9	2.3	6.1
	Efficiency loss from low and variable load operation	0.5	0.4	0.8
	Mill cycle gas	0.7	8.1	20.9
	Total cycling costs	13.3	8.1	20.9

The data in Table 7, collated from numerous studies, indicate quite clearly that costs for cold starts are significantly higher than those for warm and hot starts. The most cost-intensive factors in each type of operation fall within operation and maintenance (*see also* Section 4.4.2). These can sometimes be significantly higher than expected. For example, the cycling cost for hot starts were expected to be, on average, around $93,900 but could be as high as $121,400. The more accurately these costs can be predicted by models or even careful plant management, the easier it will be for them to be covered within the running budget of the plant. For further details on the cost data in Table 7 the interested reader is referred to the original article by Lefton and Hilleman (2011).

A detailed report by the US National Renewable Energy Laboratory (NREL, 2012) agrees that median cold start costs are around 1.5–3 times that for hot start capital and maintenance. EFOR (equipment forced outage rate) is a measure of a unit's electrical generating plant unreliability. According to the NREL (2012) there is a trade-off between high capital and maintenance costs and corresponding lower EFOR values. Figures 12, 13 and 14 show the ranges of maintenance and capital costs per MW capacity for the plants studied over 25 years in the USA for hot, warm and cold starts respectively. Danneman (2016) stresses that these costs are the 'best in class' (lower bounds) of these technologies. The worst in class (upper bounds) are not shown and could be substantially higher than these figures.

Hot start maintenance and capital costs are lower than for warm and cold starts (Figure 12 versus Figures 13 and 14), but are still significant, ranging from below 40 $/MW up to almost 180 $/MW for the smaller subcritical plants. Larger subcritical plants have a lower cost range of between around 15 and 120 $/MW and, although the average cost for supercritical plants is similar to that for large subcritical plants at around 50–60 $/MW, the range for the former is much narrower (around 40–80 $/MW). The ranges shown for gas plants show them to have similar cost ranges to supercritical coal plants but with lower average costs.

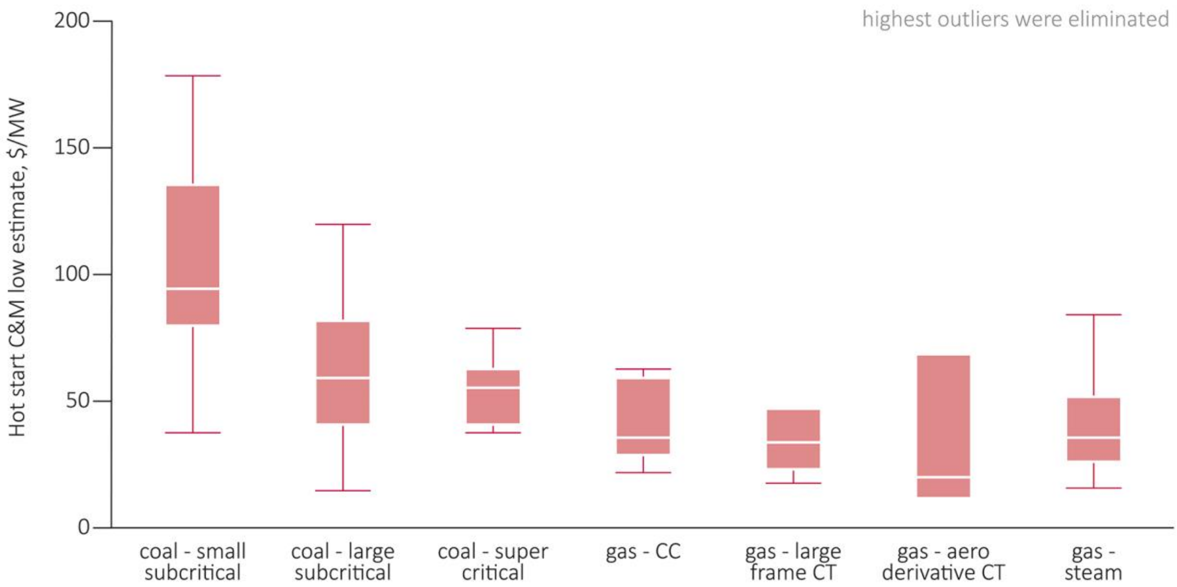

Figure 12 Hot start, maintenance and capital cost per MW capacity (NREL, 2012)

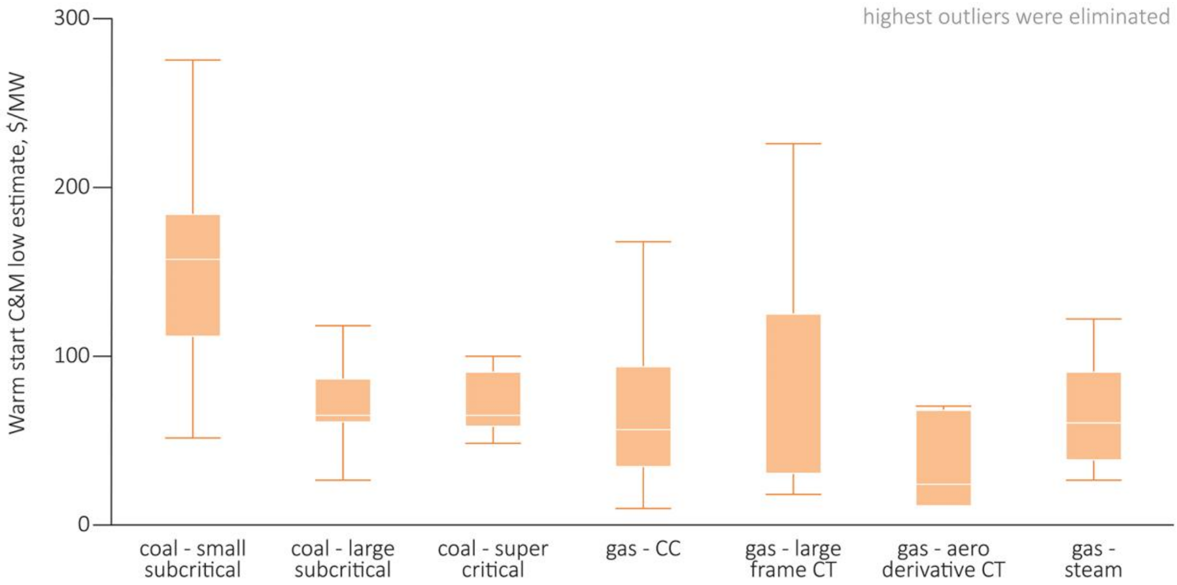

Figure 13 Warm start, maintenance and capital cost per MW capacity (NREL, 2012)

For warm starts (Figure 13) the costs are unsurprisingly higher than for hot starts, ranging up to around 280 $/MW for smaller subcritical plants. Larger subcritical plants are shown to have a significantly lower cost range for warm starts, not too different from supercritical plants, indicating the advantage of being larger (economies of scale), amongst other things. Interestingly, the diagram suggests that large subcritical and supercritical coal plants have lower maintenance and capital costs per MW hour for warm starts than many types of gas plant.

For cold starts (Figure 14), gas plants do have an advantage over all coal plants. For smaller subcritical coal plants, the costs can increase to as much as over 400 $/MW. The maximum cost for larger subcritical plants is around 200 $/MW and for supercritical plants it is around 140 $/MW.

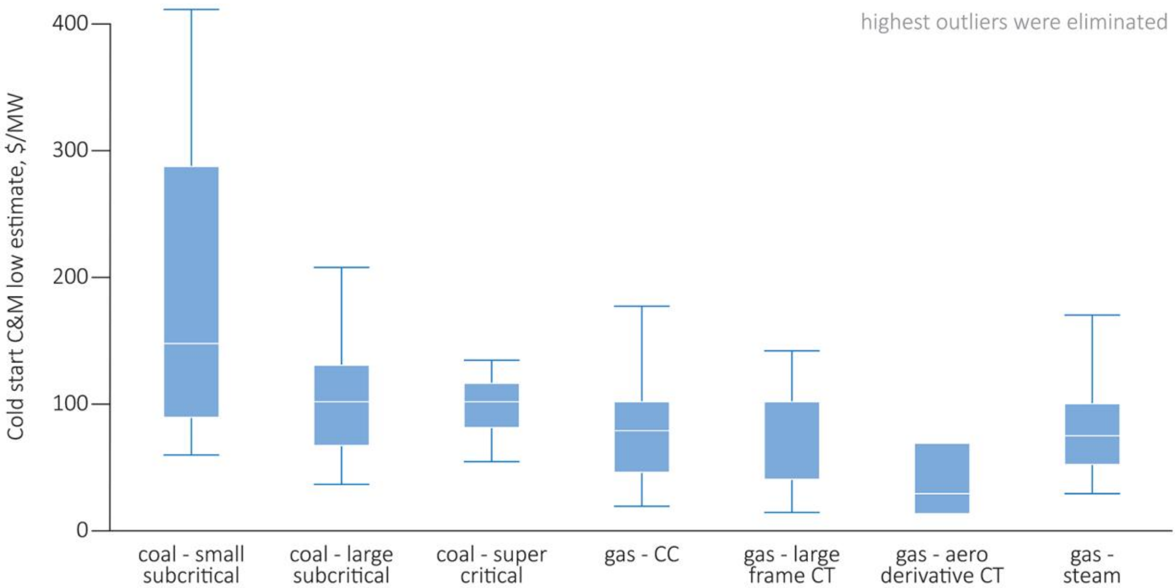

Figure 14 Cold start, maintenance and capital costs per MW capacity (NREL, 2012)

The detailed NREL report (2012) also included information on variable operating and maintenance costs, taking into account costs for equipment damage, chemicals and other consumables during operations. Conversely to the data shown in the figures above, the median costs were actually slightly higher for the supercritical units as they tend to operate at baseload. However, the median costs for variable operation and maintenance for all coal units was around 3 $/MW. Load following costs were also estimated at around 2–3 $/MW for all coal plants, the lower values being applicable to the supercritical units.

The simplest and most dramatic means of changing the output from a coal plant is to switch it off. However, on/off cycles are the most expensive means of operating a coal plant (Connolly and others, 2011) and are therefore mostly avoided. For example, every shut-down and coal start cycle at a 340 MW coal-fired unit in Texas cost an extra $157,000, including $120,000 for additional maintenance and almost $16,000 in wasted fuel (Kemp, 2013).

At times when too much power is being produced, load shedding is required at the plant. The faster this can be achieved the less unwanted power is produced. Each of the dual 1100 MW turbines in the RWE lignite-fired plant near Cologne in Germany can shed 500 MW in 15 minutes. This is still one third slower than new natural gas plants but is twice as fast as older gas plants and six times as fast as the average coal-fired unit (Fairley, 2013).

4.3 Required changes in monitoring and control

Two previous reports from the CCC deal with control systems for improved flexibility (Henderson, 2014; Lockwood, 2015). Henderson (2014) suggests that upgrading and replacing control and instrumentation in plants can greatly increase ramp rates and lower minimum loads. Studies have shown that ramp rates for a large plant can be reduced from 50 minutes for 5 MW/min rates to as little as 10 minutes at 20 MW/min by improving control instrumentation. The rate of change is dependent on the size of the unit. Improvement in monitoring and control of the turbine system can help avoid damage and wear. More advanced self-learning predictive systems are being developed which can optimise whole plant performance under different operating conditions. Lockwood (2015) looks at advanced sensors and smart controls for coal-fired power plants. Some plants may rely on such systems to optimise performance and may use such systems to monitor and improve plant performance during ramping up and cycling to keep costs and potential damage to a minimum. The interested reader is referred to this original document for more detail.

Most modern plants are fitted with sensing systems which provide data for maintenance, efficiency, risk reduction and optimisation in a real-time manner. These systems can cost hundreds of thousands, if not millions of pounds to buy, install and maintain. However, they can pay for themselves by avoiding damage and outages. For example, a sensing system at a power station in Connecticut, USA, spotted freezing issues with remote pumps and warned of potential damage in advance, avoiding $20,000 in repairs for each incident avoided. Similarly, acoustic sensors identified a leak at a steam plant at a power station in the UK, saving the plant 1500 $/d in steam loss. Putting a value on costs avoided is far more difficult than putting a value on profits made and so it is difficult to determine the money saved by the installation of state of the art monitoring and control but it is something that most experienced plant operators appreciate (Berge, 2015). As Danneman (2016) stresses, the greatest advantage of monitoring is that management is given time to prepare for a maintenance outage which can be scheduled for off-peak load periods rather than the plant being forced offline during peak periods. The change from tolerable leakage or damage to intolerable leakage or damage can happen quickly if unmonitored.

4.4 Additional costs due to damage and increased O&M

As mentioned previously, most existing coal plants were designed to work at baseload and not to ramp up and down at short notice. Such a change between the design operation and the actual operating conditions can result in damage to plant components. This section briefly reviews the types of damage that can occur as a means to gauge the potential costs incurred by such changes in operation. The previous CCC reports by Mills (2011, 2013) and Henderson (2014) look at the physical damage factors in detail. This current report focuses on costs.

According to Kemp (2013), the oldest plants in the UK were designed to last for 5000 hot starts, 1000 warm starts and 200 cold starts. Whilst that may be fine for a plant running at baseload, these limits would be exceeded relatively quickly (a few years) under current flexibility requirements. In their study of over 300 coal units in the EU and North America, Lefton and Besuner (2006) noted that the time to failure from cycling operation in a new plant is generally 5–7 years and, in older plants, can be 9 months to 2 years after the start of significant cycling.

Figure 15 summarises the different phases of flexible unit operation, providing an indication of the increased risk of damage through each (Danneman, 2010).

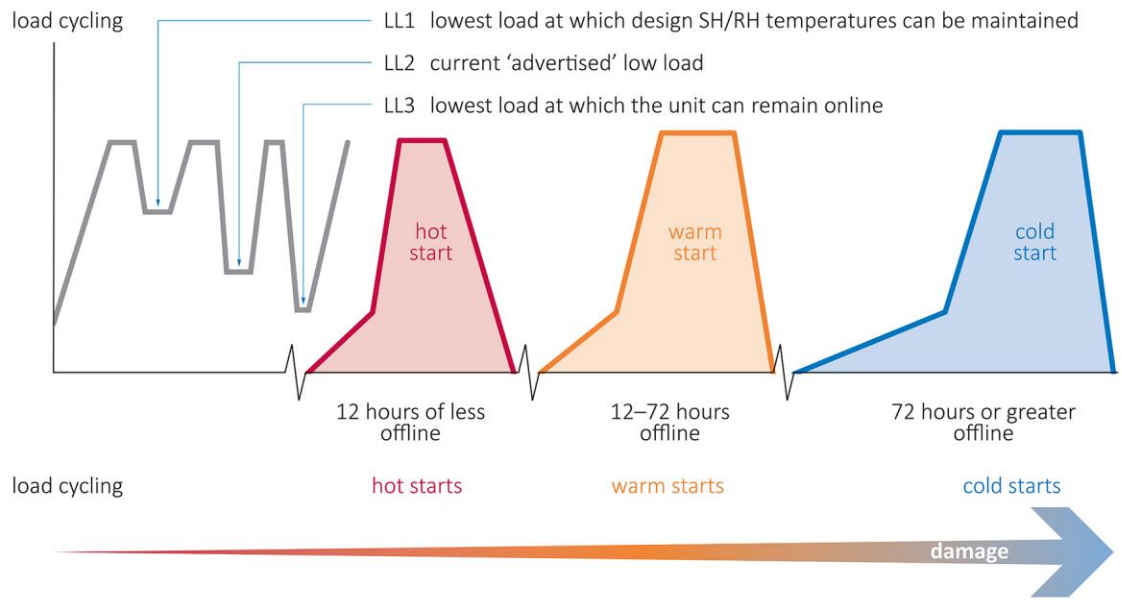

Figure 15 Damage through unit cycling (Lefton and others, 2010)

LL1 is the lowest load at which the design temperatures for the plant can be maintained – the lowest optimum operation of the plant. Moving down to LL2, the lowest advertised low load rate means moving the plant to the lowest temperature the vendor of the unit suggests is suitable. Moving down to LL3 means moving to the lowest operating conditions of the plant which are possible without shutting down the plant completely. Once shut down occurs, the start-up conditions, hot, warm or cold, will depend on how long the plant has been offline. As highlighted by the large blue arrow at the bottom of Figure 15, the risk of damage to the plant increases the colder the plant is allowed to become before restarting.

Figure 16 shows the load following scenario indicating the issues with respect to economic and emergency working rates. The red curve shows a load following scenario versus the original design load following cycle (green, with respect to economic and emergency operating ranges.

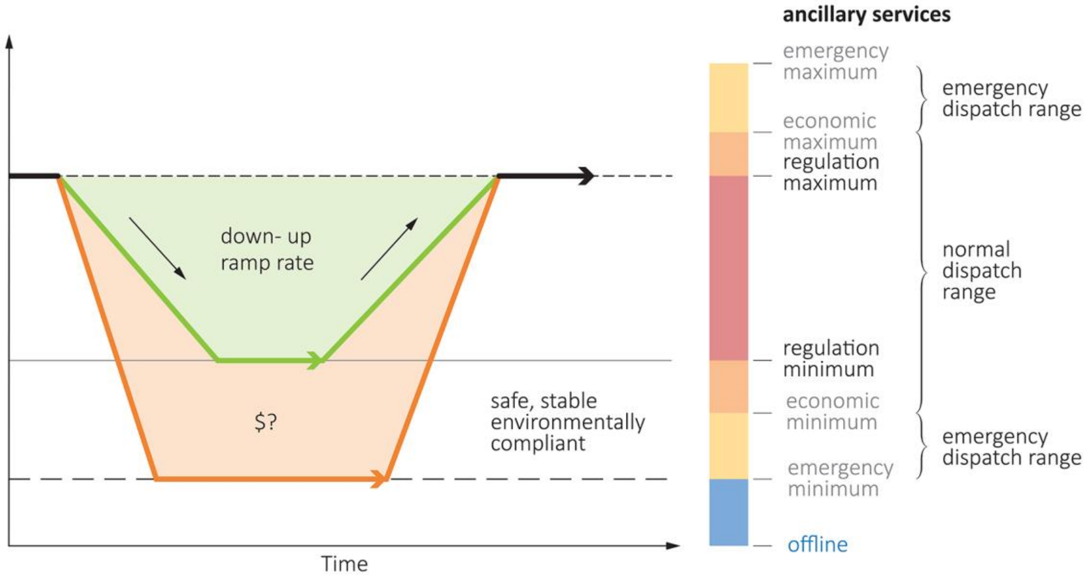

Figure 16 Deep load following scenario (Danneman, 2010)

As actual plant operation moves out of the design (green) parameters and into the red, the extremes of the operating range, the system moves out of normal economic conditions into regions where operation is either uneconomic or is achieved in such a way that plant damage may offset any benefits. As shown on the right of the graph, there are defined ranges indicating what is considered normal (regulation, intended design) for the plant, extending to what is economically feasible, and then extending out to what is achievable under emergency conditions (incurring costs and risk of damage).

The following sections look in more detail at the costs incurred in terms of equipment damage and O&M costs as a result of increased plant cycling.

4.4.1 Damage to equipment

Henderson (2014) reviews the damage to plants through non-typical operation in great detail and the interested reader is referred to this document for more information. The main cause of damage to a coal plant during normal operation is creep damage (the movement or deformation of material over time). However, when operating in a more flexible mode, power plants also encounter thermal and mechanical fatigue and stress, as well as corrosion and differential expansion. The damaging effects combined mean that there is a reduction in the working life of some mechanical parts. Replacements and repairs cost money and sometimes also cause outages whilst these replacements and repairs are being performed. Lefton and Hilleman (2011) note that 60–80% of all power plant failures are related to cycling issues. Interestingly, because the dominant failure mechanism of rapidly cycling units is not the development of creep voids, but rather a creep-fatigue interaction, the traditional basis of 200,000 h creep-based design standards is increasingly regarded for new plants as less applicable. A design life based on 100,000 h, rather than 200,000 h, without loss of actual plant life in cycling duty, is now seen as a more relevant measure of a component's durability for use under actual conditions.

Danneman and Lefton (2009) provide a simple visual of the increase in the probability of plant equipment failure over time, as shown in Figure 17.

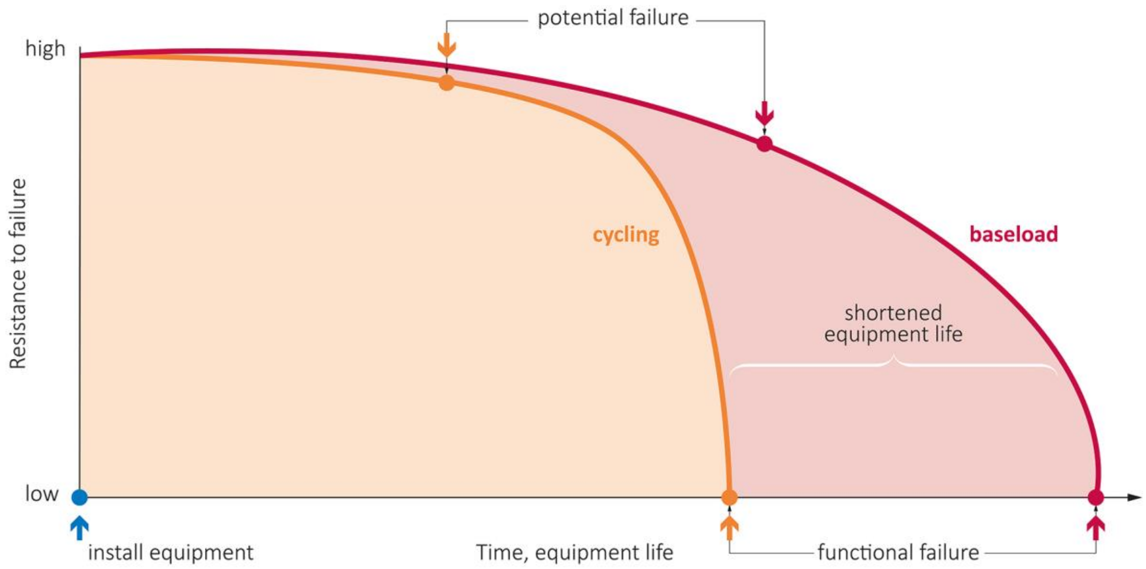

Figure 17 Probability of failure due to cycling (Danneman and Lefton, 2009)

At the beginning of a plant's life, at the left of Figure 17, it is highly resistant to failure. However, as time passes, the plant becomes more prone to problems, even running at baseload. However, by increasing cycling activity, the lifetime of individual pieces of equipment is reduced and the potential for failure increases. Latent damage to a critical power plant component often reveals itself as a failure when the unit is at full load during peak periods when steam pressures and temperatures are highest causing the greatest stresses (Danneman, 2016),

Hesler (2011) lists the potential damage arising through flexible plant operation:

- increased wear on high temperature components;
- increased wear and tear on balance of plant components;
- decreased thermal efficiency at low load (high turndown);
- increased fuel costs due to more frequent unit starts;
- difficulties in maintaining optimum steam chemistry (poor water and steam chemistry causes accelerated corrosion);
- potential for catalyst fouling on NOx control equipment;

- increased risk of human error in plant operations.

All damage and increased wear and tear will require increased spending on preventative and corrective maintenance. As Helser (2011) points out, these increased costs are particularly challenging to plants which are now sitting lower on the dispatch option list and are therefore operating less and receiving less revenue as a result.

The final bullet point on the list is human error. Hesler (2011) argues that the increased amount of transient operation increases the workload and stress on operators which produces more opportunities for error. If major errors are made, then these can be costly. However, since these events are sporadic and random, they are virtually impossible to quantify. Changes in management strategies to reduce the risk of errors are discussed more in Section 4.4.2.

When a coal-fired plant changes output, up or down, many significant effects occur within the plant – pulverisers go off and on, furnace temperatures and heat profiles are altered, pollution control requirements change, and steam and flue gas velocities vary. As Hesler (2011) emphasises, all these changes force the unit to operate away from the original design conditions. Table 8 contains a list of the most common damage mechanisms which result from changing plant operation to more flexible and therefore plant stressing conditions. Although it is possible to reduce these effects to some extent by improving plant operation and process control, Hesler (2011) states that it is impossible to completely eliminate the reduction in major component life caused by flexible operation.

Table 8 Damage mechanisms due to increasing plant flexibility (after Hesler, 2011)

Damage mechanism	Result	Cost/impact
Thermal fatigue	Cracking in thick-walled components such as turbine valves and casings caused by frequent, large temperature swings. Damage can also result from condensate forming during idling or poor control of system conditions during fluctuations	Expensive repairs and of particular concern to plant operators as cracking can cause significant damage which may lead to outages
Thermal expansion	Components such as water wall sections, gas ductwork, superheat and reheat tubing ties are designed to accommodate growth during temperature shifts but will age faster as thermal cycling increases	Increased maintenance and more frequent part replacement
Corrosion-related issues	Changes in plant operation cause changes in water chemistry. Fluxes in temperature can cause condensation leading to corrosion and accelerated component failure. Increased dissolved oxygen in feed water can arise from condenser leaks, due to more frequent shut-downs. The requirement for make-up water increases and the operation of condensation polishers and deaerators is interrupted. Corrosion and fatigue accelerates damage to water walls.	Increased maintenance and more frequent part replacement
Fireside corrosion	Increased ramp rates affect fireside corrosion and circumferential cracking	Increased maintenance and more frequent part replacement
Rotor bore cracking	Stream turbine rotors will suffer increased thermo-mechanical stress excursions and therefore low-cycle fatigue damage under flexible operating conditions	Increased maintenance and more frequent part replacement

As mentioned in Section 2.3 changes in operating conditions, especially temperature fluctuations, can cause changes in the operation of pollution control equipment.

Cochran and others (2013) report on the evolution of a baseload coal plant (unnamed multi-unit plant in North America) into a flexibly operating unit. Over the course of the plant life it experienced 523 cold starts (7–8 hours to sync), 422 warm starts (4 hours to sync) and 814 hot starts (1.5–2 hours to sync). During that time, the plant reported the following issues:

- boiler tube failure;
- cracking of welds, headers and valves;
- cracking of generator rotors;
- oxidation in boiler tubes;
- condenser problems (thermal stresses);
- migration of turbine blade parts.

Lefton and Hilleman (2011) reported the most common problems identified within 215 steam plants operating in North America and Europe, as shown in Figure 18.

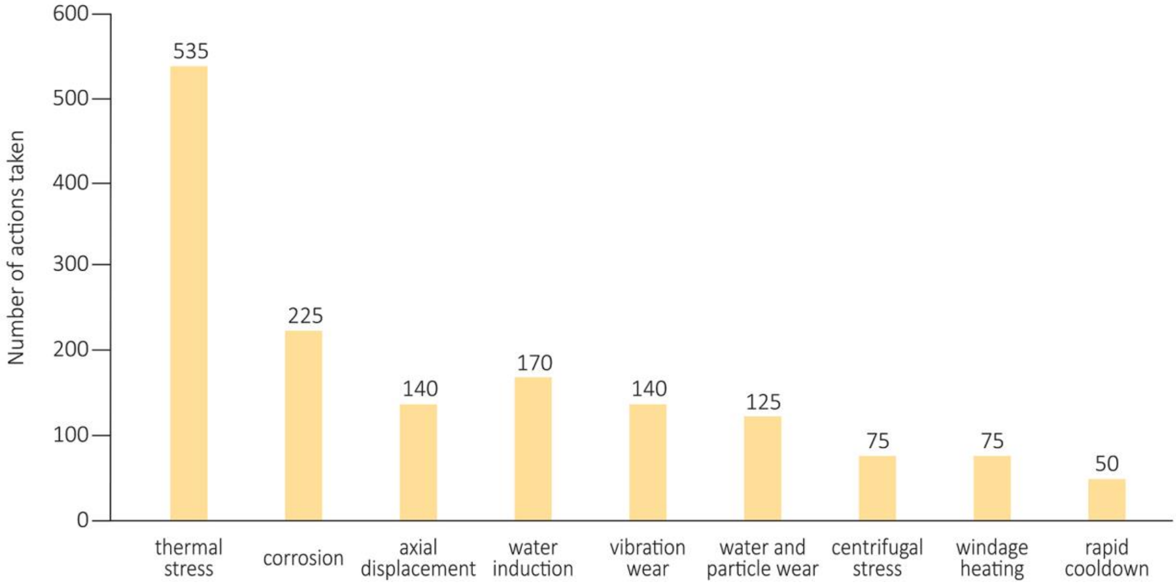

Figure 18 Common problems in cycling plants (Lefton and Hilleman, 2011)

The figure identifies thermal stress as the most common issue by far with over 535 individual events occurring which required maintenance or repair.

Proper management and protection of the entire steam circuit (boiler, piping, feed water and turbine) should be optimised during flexible operation to avoid temperature stresses as well as condensation and corrosion issues. The Electric Power Research Institute (EPRI) have produced guidelines for this which include procedures and recommendations for the different periods of plant operation (start-up, shut-down, cycling and so on) (Hesler, 2011).

As mentioned previously, the issue with SCRs during flexible operation are due to the temperature drops causing the chemistry to change, especially the production of ABS. Economiser bypasses can be used to keep the flue gas temperature elevated but these are not present or cannot be retrofitted on some plants. In these circumstances the following tactics may be applied (Hesler, 2011):

- evaluate the actual conditions within the SCR and compare these with the design conditions;
- modify operational practices (such as fuel sulphur content and NOx reduction levels);
- improve SCR temperature distribution by installing a static mixer.

4.4.2 O&M

Wagman (2012) cites data which suggest that O&M costs for all types of fossil generation across the Western Interconnection in the USA may increase by $35–157 million per year due to cycling.

Continuously altering plant operation to maintain required output can have negative effects on plant operation but can also put increasing pressure on plant operators, leading to potential operator error (MIT, 2011).

According to MIT (2011), "plant managers may not fully understand the costs associated with the physical wear from flexible operation and this will limit their ability to recover those costs. In the long term, these price signals may discourage future investment in flexible operating technologies that will be necessary when older plants retire, electricity demand grows, and intermittent renewable capacity expands". Kumar and others (2012) note that O&M is the one area where costs are currently rising at a rate faster than inflation.

Danneman (2010; also Danneman and Lefton, 2009) considers two different approaches to evaluating the cost of wear and tear/damage. The top down approach is based on looking at costs (maintenance, capital, capacity replacement) and performing statistical analysis and using expert opinion to analyse the results and produce recommendations. The bottom up approach concentrates more on on-site plant performance assessments and analysis of actual cycling related costs. The methodology to provide top-down and bottom-up analysis of potential costs, is shown in Figure 19.

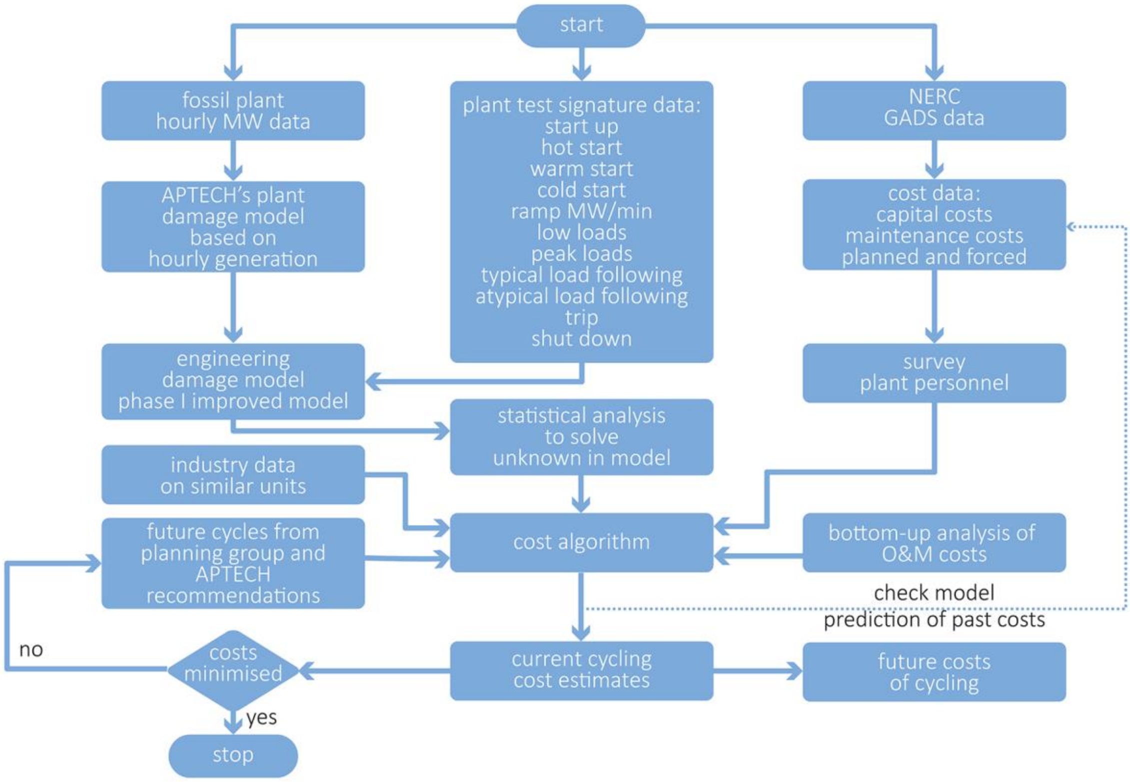

Figure 19 Methodology for estimating O&M costs (Lefton and others, 2010)

By recording monitoring information and records of costs over time, the plant manager will have more information to hand in order to model potential future costs, including EFOR (equipment forced outage rate). The flowchart shown in Figure 19, produced by APTECH Ltd, USA, shows a detailed and involved model based on actual plant data which can be used to estimate future cycling costs. The model includes plant operating data but also information from the unit personnel, as well as models which take individual equipment operational characteristics into account. It is beyond the scope of this report to explain the model in detail – the interested reader is referred to the papers by Danneman included at the end of this report for further information.

If a plant manager is aware that his plant will be called upon for more flexible operation, then there are ways in which the plant can be adjusted to facilitate better operation. Figure 20 shows the effects of cycling on plant life (Danneman and Lefton, 2010).

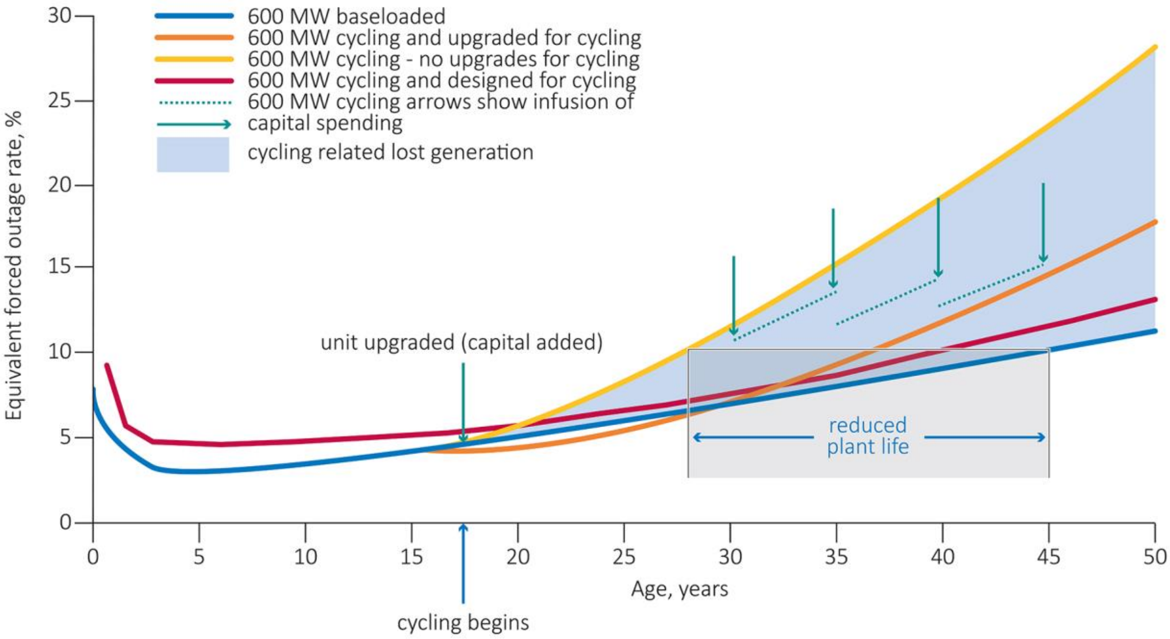

Figure 20 Cycling effects (Lefton and others, 2010)

Figure 20 shows the equivalent forced outage rate versus that age of the unit for four scenarios from the commencement of cycling. The average plant will start to age after about 20 years of operation. If it continues to run at baseload, as designed, then the plant can continue relatively well for several more decades. However, the stresses of cycling are clear. If there is no upgrading with measures to counteract increased wear and tear, the equivalent forced outage rate (for repairs and maintenance) will increase at quite a significant rate, as shown by the steep yellow curve. However, if adjustments are made to maximise flexibility for cycling, as shown by the brown curve, then the life of the plant may not change much at all. However, the blue lines show that, in order to achieve this, capital spending is required.

As noted by Lefton and Hilleman (2011), understanding the costs of maintenance and repair is necessary for plant management – if costs are unknown then making a profit becomes a matter of luck rather than good management. And so plant operators have developed means to evaluate plant performance whilst taking costs and pro-active management practices into account.

Operating plants in flexible conditions lowers the efficiency of the plant. By performing plant upgrades, this efficiency can be regained. However, plant upgrades are not cheap and there must be a balance between the cost of the upgrade and any potential increase in revenue as a result. The decision to upgrade must be made by an expert who can take all the costs and benefits into account in a qualified manner. These upgrades will be plant specific but are likely to include options such as changing to sliding pressure operation, variable speed drives for main cycle and auxiliary equipment, and boiler draught control schemes. Hesler (2011) also includes 'operating philosophy' here, as a reminder that the skill of the plant operator and changes in how the plant is managed can play a significant role in improving plant efficiency.

Cochran and others (2013) suggest that flexibility changes require limited hardware modifications but extensive modifications to operational practices. Strategic modifications, proactive inspections and training programmes can minimise the extent of damage and optimise the cost of maintenance.

Although it was impossible to put an actual value on costs, Cochran and others (2013) report that of the changes made to an unnamed coal plant in North America to increase flexibility, 90% of the future savings in costs came from adjustments to operating procedures.

Cochran and others (2013) discuss the operating procedures which facilitated the increased flexibility of an unnamed coal generating unit in North America. Maintenance procedures were changed to involve increased monitoring of potential areas of concern such as increasing the frequency of inspection of breakers and close observation of the water chemistry, requiring chemistry staff onsite at all hours. This meant that the plant manager had more information to hand on the state of operation and maintenance to ensure smooth and efficient running of the plant whilst avoiding breakages and damage. Decisions on whether to replace or modify pieces of equipment were made on a case by case basis taking into account wholesale market opportunities to establish whether the cost of any repair or replacement work (and associated forced outage) was justified. According to Danneman (2016) cycling damage causes increased risks such as boiler tube leaks, power piping failures, pressure vessel failures, pulveriser explosions, coal silo fires, turbine blade failures and transformer fires. These types of events are often categorized as low probability-high impact events but they can cause serious injury, fatalities and substantial property damage.

Hesler (2011) describes the strategy toolbox used by E.On to manage cycling issues and these are summarised in Table 9.

Table 9 Strategies for managing cycling (Hesler, 2011)					
Area	**Target**	**Action**	**Requirements**	**Cost/benefits**	**Timescale**
Studies	Improve plant performance	Monitoring and modelling to identify potential issues followed by testing	Measurements and repeated testing trials	Case dependent. Cost thousands of dollars to hundreds of thousands but if operating costs are reduced then worthwhile	Weeks/months
Coaching	Improve operational skills	Train staff with programmes such as how to predict and avoid creep	Initial investment in techniques, updated as necessary	Relatively low costs which may result in significant savings in terms of damage and accident avoidance	Continual
Maintenance	Forward planning for avoidance of damage issues	Continual assessment and monitoring within plant	Increased vigilance and monitoring	Case by case basis but should be relatively low costs and result in significant savings in terms of damage and accident avoidance	Updated every 3–4 years
Design	'Design out' damage mechanisms	Replacement of components and materials based on known extent of damage occurring per cycle	Monitoring of damage in an ongoing manner. Planned modifications and retrofits	Case by case. Could be expensive and require plant to be offline for an extended period but could avoid significant damage costs	Continual
Damage estimation	Predict when replacements will be required and budget accordingly	Replacement of components and materials based on known extent of damage occurring per cycle	Monitoring of damage in an ongoing manner. Planned modifications and retrofits	Case by case. Cost can be estimated and budgeted in advance. Could avoid significant damage costs	Continual
New build	Plant replacement with more efficient system	Incorporate lessons learned to design to requirements	Tear down and rebuild	Millions – billions	Once

The costs of each of these options is unclear and will vary on a case-by-case basis. But Hesler (2011) gives an example of a study on methods to reduce thermal transients during reduced hot start-up times which resulted in savings of, for example, $1,292 per start (due to fuel, auxiliary power and water costs, 1990s study).

Danneman and Beuning (2010) have carried out numerous studies on plant performance in the USA and have summarised five categories of methods for changing O&M practices to reduce or optimise cycling:

1. Increase preventative and corrective maintenance on wear and tear issues:
    - Critical component failure analysis (fatigue, thermal shock, creep, oxidation, differential expansion, depositions, corrosion product migration);
    - Root cause analysis of failed components;

- Condition assessment;
- Monitor cumulative damage.

2. Change operating procedures to minimise thermal corrosion and mechanical cycle damage (start-ups, ramping to load, load changes, shut-downs, shut-down protection).
3. Upgrade equipment to reduce wear and tear damage and/or reduce repair costs
   - Remote control for vents and drains;
   - Turbine bypass;
   - Economiser recirculation;
   - High grade metal alloys;
   - Upgraded digital control systems and actuators;
   - Flexible pressure part design and connections;
   - Water chemistry monitors;
   - Metal thermocouples.
4. Wind curtailment dispatch procedures that reduce cycling.
5. Energy storage and/or demand response processes.

The last two items in this list are means of reducing the requirement for plant modification rather than actual means of modification but are worth remembering here – one of the best ways of reducing stress effects on any system is to reduce or remove the source of stress.

Although somewhat dated, Lefton and Besuner (2006) discuss a computer programme produced by APTECH designed to collate data to monitor and control operations and maintenance. The programme is able to calculate wear and tear/cycling costs of start-up, load change, or steady state plant operation. The model uses plant specific data collated over time and therefore becomes tuned to the characteristics of each plant in a unique way, providing predictions of maintenance requirements and projected costs tuned to each specific unit. Whilst a model such as this, and the associated monitoring equipment network throughout the plant, could be expensive (no price given) the benefits are likely to make the investment cost-effective.

4.5 Effect of renewable intermittency on coal cycling costs

The costs of additional wind capacity on the cost of coal plant cycling for the Public Service Company in in Colorado, USA, were studied by (Connolly and others, 2011). Figure 21 shows the impact of wind generation in Colorado on the coal unit cycling.

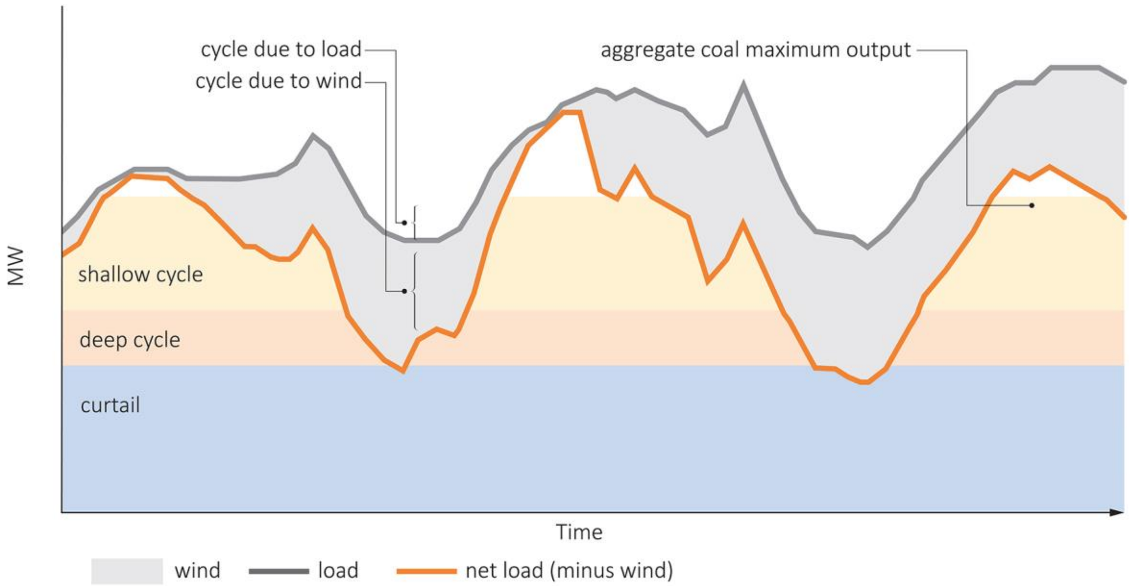

Figure 21 Impact of wind on coal unit cycling (Connolly and others, 2011)

The figure shows that small levels of wind generation (when the grey section is narrow) have little or no effect on coal cycling. The net load (red line) remains above the aggregate coal baseload maximum output. As the wind output increases (expansion in the grey area) then coal output must be reduced, requiring plants to cycle down into the shallow and eventually deep cycle zones.

The study by Connolly and others (2011) was based on two separate production cost models and considered the cost of plant cycling to reduce output from coal units but also considered the cost of curtailing wind energy to reduce the cycling required by the thermal plants. Although wind power production has no fuel or production costs, as such, the economics of their operation must take into account loss of any relevant production tax credits, default costs from power purchase agreements, carbon mitigation costs, renewable energy credits and so on. The study evaluated two protocols:

- **Deep cycle** – cycling coal plants down to their lower emergency levels (‘deep cycle’). This mode of operation maximises potential wind output whilst minimising coal burn and associated CO_2 emissions but may result in reduced system reliability, and increases wear and tear resulting in more coal unit outages. This protocol prioritises the output from wind at the risk of potential damage to coal units.
- **Curtail** – cycling coal plants down to minimum economic generation levels (‘shallow cycle’) to accommodate increasing wind. However, wind curtailment may be required if the net load falls below the aggregate coal fleet minimum deep cycle level. This mode requires some reduction in wind output, relying on less wind production than the ‘deep cycle, but avoids the potential damage caused by deep cycle operation of the coal units.

The pros and cons of the protocols are summarised in Table 10.

Table 10 Qualitative factors for different protocols (Connolly and others, 2011)

Protocol	Pros	Cons
Curtail	Impacts are more certain	Less wind energy delivered
	Costs are easily quantified	Higher CO_2 emissions
		Possibly higher CO_2 price risk
Deep cycle	More wind energy	Unpredictable timing of cash expenditures
	Lower CO_2 emissions	Uncertain impact of operating at emergency minimums, increased risk of damage and outages
	Possibly lower CO_2 price risk	

Although the cycles required the plant to run in different manners, the study did not identify any significance difference in the cost of each protocol. Table 11 shows the difference in cycling and levelised costs under the two different cycling protocols.

Table 11 Summary of scenario results from 2011 to 2025 (2010 present value) (Connolly and others, 2011)

Installed wind	Cycling protocol	Cycling cost component ($million)	Curtailment cost component ($/million)	Total levelised actual costs ($million)	Total levelised cost ($/MWh)
2 GW	Curtail	3.6	1.2	4.82	0.77
2 GW	Deep cycle	5.1	0.1	5.21	0.83
3 GW	Curtail	5.0	3.3	8.30	1.03
3 GW	Deep cycle	8.2	0.6	8.75	1.08

It is interesting to note that Connolly and others (2014) explain that cycling is used to ramp coal plants from minimum to maximum output but state that "shutting down a coal plant to accommodate wind was determined to be uneconomic".

As shown in Table 11, cycling and levelised costs for curtailed operation is found to be slightly less expensive than deep cycle operation. Curtailed operation has been selected by the Public Service Company of Colorado as the best mode of operation for their coal plants largely because of the lower risk to plant reliability and of damage.

Connolly and others (2011) noted that the incremental quantity of wind has the largest impact on cycling costs in the first year of installation and that costs reduced after that. This assumes that loads increase over time and that baseline units which retire are replaced with more flexible options. With more wind and more flexible coal in future the smaller the gap between minimum system load and baseload maximum. An increase in wind will mean more output from this source reducing the times when coal capacity is required to cycle. As a result of these effects, Connolly and others suggest that increasing wind production and reduced coal cycling over time will reduce the overall costs in the long term.

Wagman (2013) cites the data shown in Table 12 to demonstrate the increased cycling and ramping costs at fossil fuel plants due to renewable penetration in the USA.

Table 12 Renewables increase cycling and ramping costs (Wagman, 2013)

Scenario	Cycling and ramping costs, $million	Increased cycling and ramping costs due to renewables, $million	Increase, %
No renewables	271–643	NA	NA
High wind	321–769	50–126	18–20
High mix	306–738	35–95	13–15
High solar	324–800	53–157	20–24

Based on actual plant data, Table 13 shows the impacts in terms of wear and tear costs encountered in practice at three Xcel plants in the USA (Danneman, 2010).

Table 13 Deep load following impacts to Xcel Energy wear and tear $ (Danneman, 2010)

Plant, lower minimum and faster ramp rates	Annual cycling impact (maintenance, capital, EFOR-replacement energy, fuel, chemicals, 2000–2013)
Pawnee Unit 1, ~325 MW swing	Annual cycling cost ⟹5X 50% O&M, 10% capital, 40% fuel
Harrington Unit 3, ~200 MW swing	Annual cycling cost ⟹3X
SherCo Unit 2, ~425 MW swing	Annual cycling cost ⟹2X

Clearly cycling costs can increase significantly, by orders of magnitude, when plants are operated outside their design parameters, although cycling costs may only be a fraction of total operating and maintenance expense.

4.6 Comments

In order to ramp coal plant output up and down to provide flexible power to balance the grid, changes have to be made in the way the plant operates. In general, this means increasing or decreasing the output by varying fuel input and the number of units/mills in operation at any time. Changes can be made relatively rapidly (in terms of hours or less). However, ramping unit operation up and down results in rapid changes in temperature and often associated changes in moisture balances through the plant – and this can cause damage. And so, while the lifetime of some coal plants is being extended, the lifetimes of individual plant components are often reduced, with damage occurring much earlier than predicted for baseload operation. Increased wear and tear issues and even breakages increase the plant EFOR and incur costs to replace parts and also to upgrade parts to cope with more flexible operation. Increasing monitoring activity and developing improved monitoring protocols can provide early warning and even predict required maintenance in advance, reducing the risk of unexpected outages. A changes in O&M practices and increased monitoring can, itself, incur costs but in most cases the investment is well worth the reduced EFOR.

However, even with the increased investment in O&M, increasing plant flexibility can add costs in terms of millions of dollars to the operation of a coal plant, increasing cycling costs by orders of magnitude. The balance of cost and expense must be determined on a plant by plant basis – there are few cycling related costs for baseload plants but significant cycling costs for plants running in a more dispatchable manner.

5 National issues

A growth in renewables capacity is happening faster in some regions than others. At the moment, most of the activity is in developed countries where the energy infrastructure is already largely established and fossil fuel technologies without carbon capture are being phased out to comply with tightening emission limits on particulates, SO_2, NOx and mercury. For this chapter, three countries have been chosen to demonstrate the costs and challenges of intermittency, simply because these are countries where this is an issue and for which a good amount of published information is available.

5.1 USA

In 2010 around 88% of the US electricity generation was provided by coal, natural gas and nuclear (MIT, 2011) – much lower levels of renewable energy are in place than in the EU. President Obama's Clean Energy Plan aims to reduce CO_2 emissions by 32% by 2030 (based on 2005 levels). Within this, the share of renewables is expected to rise to 28% by 2030. According to Hesler (2011) wind generation alone increased from 18 TWh to 71 TWh between 2005 and 2009. The total non-dispatchable generation in the USA increased by a factor of four during this same period. And the renewable energy produced is a 'must-take', meaning that it is prioritised over any other output. Wind farms are being built with more dispatchable characteristics (storage or spinning reserve capabilities) but the current incentives tend to prevent the use of wind for dispatch control (Danneman, 2016).

Individual states within the US are taking varying approaches to the integration of renewable energy with different levels of success. By 2012 there were three regional transmission organisations with significant wind portfolios, together accounting for 27 GW of wind. The largest wind capacity is in Texas (Lesser, 2013). The cost of integrating the first 10 MW of wind into the ERCOT portfolio in Texas was estimated at 0.5 $/MWh, far below the estimates of 2–5 $/MWh or even 6–11 $/MWh, as previously estimated. However, the lower value did not take into account the investment in new transmission lines and grid infrastructure to feed in this new wind power – Texas has invested $6.9 billion in new transmission infrastructure. Both Texas and Colorado have invested significantly in wind but are largely isolated from surrounding systems which limits their ability to call on the flexibility of dispatchable units in times of need. ERCOT has established a nodal market, with locational marginal prices that tie local grid conditions to the value of electricity delivered. Xcel, in Colorado, has two thirds of its wind turbines feeding into automatic generation control systems, keeping them constantly connected to the grid operation centres, allowing balancing within themselves (St John, 2015). This should serve to take some pressure off dispatchable plants such as coal units. Xcel have carried out a significant amount of research on the effect and cost of wind integration on the existing coal fleet in Colorado and Minesota, much of which has been included in earlier technical chapters of this report (Danneman and Beuning, 2010; Danneman, 2010; Danneman and Lefton, 2009).

In 2009, over 60% of the total coal-fired generation in North America was from units commissioned before 1980 – that is, baseload plants which are not designed for particularly flexible operation. However, since 1980, most of the plants built have been large capacity, higher efficiency units with supercritical steam conditions. These plants were also designed for baseload operation but are easier to run under flexible conditions than the older plants (Mills, 2013).

According to Lesser (2013), the continued subsidies for wind generation in the USA (as tax credits and mandatory renewable portfolio standards) represents bad economics and bad energy policy. Lesser (2013) argues that the wind generation tends to displace low variable cost generation or simply forces baseload generators such as coal to pay greater amounts to supply electricity to the grid because their units cannot be turned off cost-effectively. Since 2004 there has been an increase in reserve shut-down hours for baseload coal plants, for all units from subcritical to supercritical. This has resulted in a reduction in the reported net capacity factor, especially for older subcritical units, which are experiencing several issues including decreased thermal efficiency at low load and increased fuel costs due to more frequent unit starts (Hesler, 2011; Kemp, 2013).

5.2 UK

The UK Government aims to have 30 GW of peak capacity wind power by 2020, enough to provide around a third of the nation's electricity. This could lead to an excess of 26 GW when wind conditions are good and demand is low. Conversely, it could lead to shortages of 10 GW during periods of calm. To meet the intermittency demands, 8 GW of reserve will be required, more than twice the 3.5 GW which was available in 2010. The UK's move away from coal, especially in Scotland, means that the shortfall in dispatchable power will become more and more dependent on pumped hydro, diesel, gas and by managing the industry's electricity demand (Haworth, 2010). The UK supports renewables through feed-in-tariffs, the Renewables Obligation (requirement for electricity suppliers to source a specified proportion of their electricity from renewable sources) and contracts for difference (CfDs; which guarantee renewable electricity generators a fixed price for their electricity for 15 years) (HP, 2014).

Haworth (2010) noted that the UK's target of 20% renewable energy by 2020 is proving challenging, suggesting that, if 13,000 wind turbines (40 GW total capacity) were installed they would only be able to provide around 3.6 GW of reliable energy, equivalent to 7% of the country's peak winter demand. The installed capacity would have to increase from 76 GW to over 100 GW at an estimated cost of £100 billion to ensure reliability of supply (Haworth, 2010).

The UK faces a challenge to keep up with the electricity demand as the contribution from renewables increases. The closure of coal plants means that the amount of spare capacity in the country for the 2015/2016 winter was between 4–7%. This is a relatively low amount of spare capacity (HP, 2014). In November 2016, four power stations in the UK were offline unexpectedly, sending the wholesale price of electricity from an average of around 60 £/MWh to emergency payments of 2500 £/MWh. The margins between peak supply and demand have decreased considerably since several coal-fired plants have been closed down. Load shedding is also becoming more common where industry and commercial companies are paid to turn power down or off when the generation capacity is challenged. It has been suggested that this can be a more cost-effective way of matching supply and demand than building large power stations.

Margins of spare capacity will be small for the next few winters until new back-up power starts coming on-stream in 2018/19 (Financial Times, 2016a).

In early 2016, the UK Government agreed to offer more subsidies to baseload power suppliers in the UK and to increase penalties for those who fail to produce on agreements. This is being done in an attempt to make 1 GW more power available to expand the UK's slim margin of peak supply over peak demand. The subsidies are intended for new build back-up power but appears to be being delivered more often to operators who use diesel generators and to existing nuclear plants. Consultations are ongoing as to the controversial issue of subsidies being received by relatively highly polluting diesel generators (Stacey, 2016).

Although somewhat dated, the report by Gross and others (2006) gives some interesting values relating to the costs of increasing renewables in the UK. It was suggested that, if intermittent renewables penetrated up to 30% of the electricity supply, additional system balances to support the associated fluctuations would amount to only 5–10% equivalent capacity and that this would incur associated short-term run balancing costs of 2–3 £/MWh. However, costs to maintain higher system margin reliability would be 3–5 £/MWh (at 20% wind penetration), producing a total cost of 5–8 £/MWh. For comparison, the cost of wind generation would be around 30–55 £/MWh. The associated impact of intermittency on consumer electricity prices would be 0.1–0.15 pence/kWh. In a more recent paper (Gross, 2012) estimates that the cost of intermittency adds around £6–8 to the annual cost of electricity in a UK household. Other reports put this value at as much as 214 £/y by 2020, although official government estimates put the cost to the average UK householder at 5% of current electricity bills but increasing to 11% by 2020 (equivalent to £141 on an average annual bill of £1319) (Gosden, 2015).

Interestingly, the UK Government has acknowledged that the intermittency of wind in the UK may increase the CO_2 intensity of fossil-fuelled generation (HP, 2014).

5.3 Germany

In 2010, Germany introduced its 'Energy Concept', known as the 'Energiewende', based on increased renewables, competitive energy prices and a continuous, secure supply of electricity. The concept aims to reduce fossil fuels and increase renewables with an ambitious target that relied heavily on the continued use of nuclear power. However, following the Fukushima nuclear disaster in March 2011, Germany decided to phase out 8.4 GW of nuclear power immediately and close the remaining 12.1 GW between 2015 and 2022. The target for renewables was then adjusted somewhat, with the targets currently at 35% renewable by 2020, 40–45% by 2025 and 80% by 2050 (Schiffer, 2014).

As shown in Figure 22, the Germany energy plan requires a significant reduction in energy demand (through energy savings as well as through importing more from surrounding countries. However, despite this, the projected cut in conventional energy is enormous and poses a significant challenge, especially bearing in mind the intermittency of the renewable energy systems which will be expected to provide 80% of the country's energy demand by 2050.

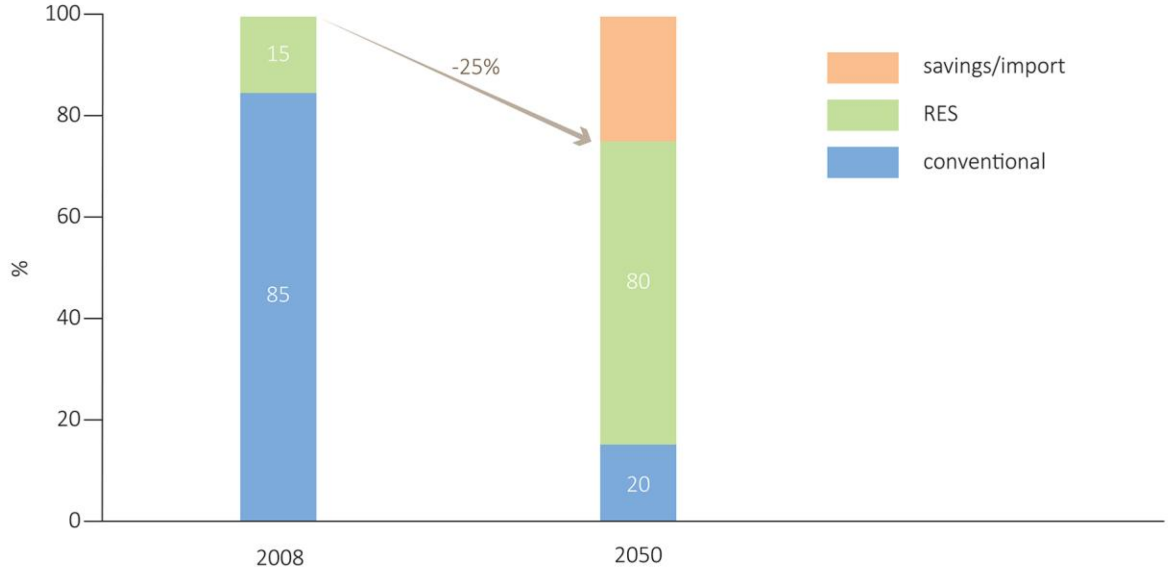

Figure 22 Germany's plan for a shift to 80% renewables by 2050 (Then, 2015)

Around 34% of the renewable energy in Germany in 2013 came from wind, 28% from biomass combustion, 21% from solar, 14% from hydro and the remainder, 4%, from waste combustion. Then (2015) emphasises that this increase in renewables does not provide sufficient baseload and that 45–65 GW of fossil capacity will still be required in Germany in 2050.

In 2014, solar and wind power supplied 80% of peak demand during specific periods of the day, although the annual average was 30% from renewables (Krishnaswamy, 2015). However, there have been days when the wind power has been less than 10%, sometimes for periods of over 12 days, as shown in Figure 23.

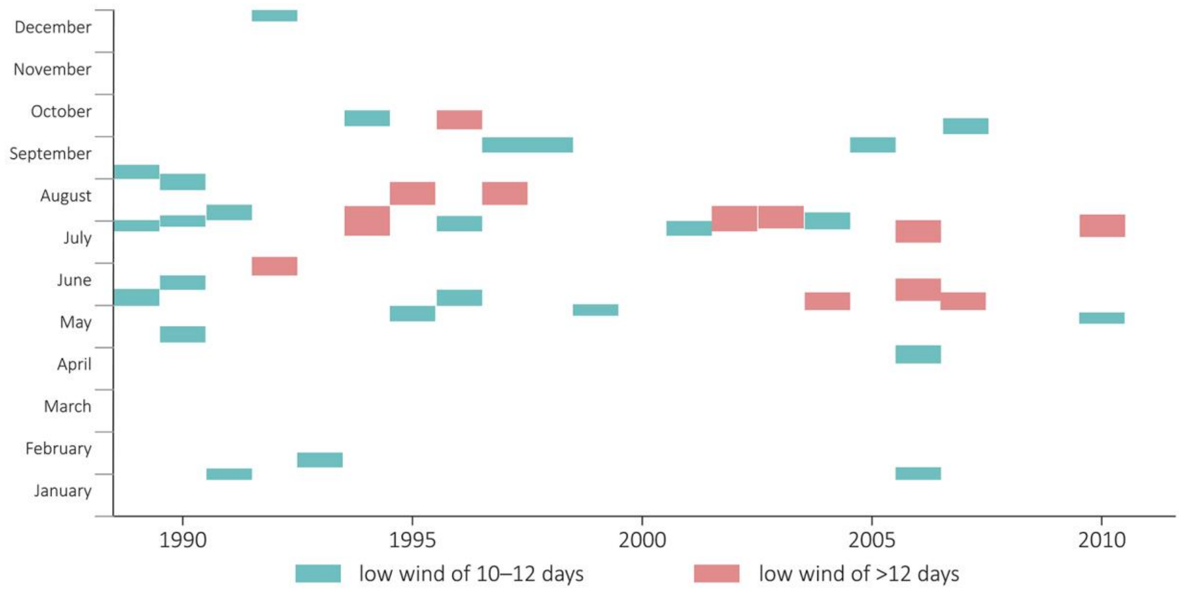

Figure 23 Days with less than 10% wind power generation in Germany: frequency generation over the last 20 years (Eurelectric, 2011)

The renewables capacity has grown at an annual rate of 13.6% between 2006 and 2012 but this decreased to 3.6% during 2013–2014 as the market matured and the subsidies started to fall. In 2012, a relatively windy and sunny year, 142.5 TWh was generated from renewables. However, despite a slight increase in capacity, this dropped by 30% the following year. Although Germany closed 2.3 GW of coal-fired plants between 2010 and 2014, the generation from coal remained relatively stable, dropping only 3% between 2010 and 2014, from 99.7 TWh to 96.5 TWh. Coal generation actually reached 110.7 TWh in 2013, the highest in almost a decade. The first half of 2015 saw a rise in coal generation of 2.9% suggesting that coal is still an important part of Germany's energy supply (Perret, 2015). The high price of gas in Germany will mean that coal plants will be required for many years yet (Fairely, 2013).

Figure 24 shows the mismatch between the energy capacity of the different fuel types in Germany and the actual energy production, as recorded for December 2013 (Schiffer, 2014).

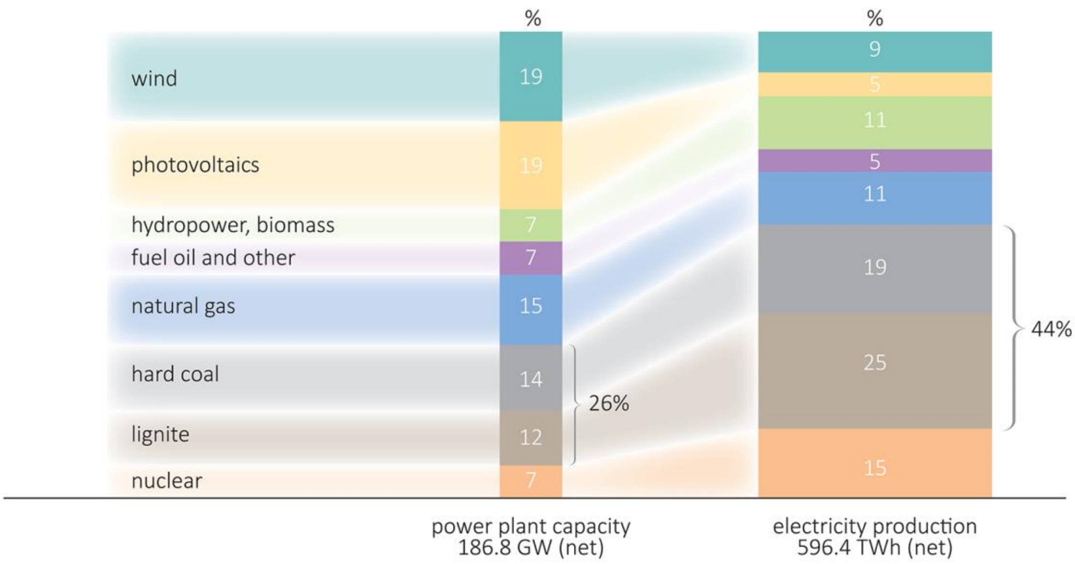

Figure 24 Percentages of capacity and production of various electricity sources in Germany, December, 2013 (Schiffer, 2014)

The renewables sector in Germany in 2013, wind, solar, hydro and biomass, provided a total capacity of 45% of the required production. However, conditions were such that this sector only produced around half of that – 25%. Meanwhile, the gas, hard coal, lignite and renewable plants were called upon to make up the difference to meet demand. It is quite clear from Figure 24 that coal and lignite are arguably pulling more than their fair share of the workload. It is important to emphasise the difference between capacity and production. For many renewables the difference between total capacity and actual production can be almost 100%.

The current Renewable Energy Sources Act (1 August 2014) guarantees feed-in tariffs for renewable energy sources for 20 years after commission and the grid is obliged to purchase the entire renewable energy output as a priority. The deficit (feed-in tariff minus the market energy price) is passed on to the customer. This is costly. The remuneration paid to plant operators and premium payments amount to €20.4 billion in 2013. Deducting income from marketing, net subsidy payments were around €16.2 billion in 2013. As of January 2014, the charge passed to consumers as a result of this was 62.40 €/MWh, a value which is now twice as much as the wholesale price of electricity. Consumers in Germany pay a higher price than any other customers in Europe, other than Denmark. At the moment, German consumers pay bills which include costs towards the renewables obligation including 24.6% towards grid charges, 22.2% renewable energy surcharges, as well as an electricity or 'ecological' tax of 7.2% (CEW, 2016).

The German electricity prices are currently over twice the OECD average and three times as high as the USA (Schiffer, 2014). Wholesale electricity prices have dropped from 60 €/MWh in 2011 to 20 €/MWh in 2015/16 (Chazan, 2016a,b).

Wholesale electricity prices in Germany are expected to continue to decline to 2020 and beyond due to the continued increase in renewables, and this could result in an annual revenue loss across the industry of €2.96–3.88 billion. The revenue change will affect those generators with higher marginal costs the most as the frequency at which they can be dispatched profitably will decrease more than for cheaper generators. Dispatchable technologies, such as fossil fuel plants, will have fewer guaranteed sales and will, instead, have to bid against each other to provide sporadic dispatch power. This will bring the cost down. For this reason, gas plants are most likely to be phased out due to unfavourable economics, leaving more pressure on plants such as coal units to take up the slack (Adelfio, 2014). Germany's largest utility, Eon, has recently reported its biggest annual loss (€7 billion net) after writing down the value of coal and gas plants, highlighting the crisis in Germany's power industry. RWE, a rival generator, also ran at a loss in the country in 2015, due to €3 billion of impairments (Chazan, 2016a,b), reporting a net loss of €170 million for 2015. According to Chazan (2016b) the relationship between management and investors is 'scratchy' which could mean lower investment in upgrades and repairs on existing units.

Figure 25 shows the effect of the increase in renewables on the wholesale price of electricity.

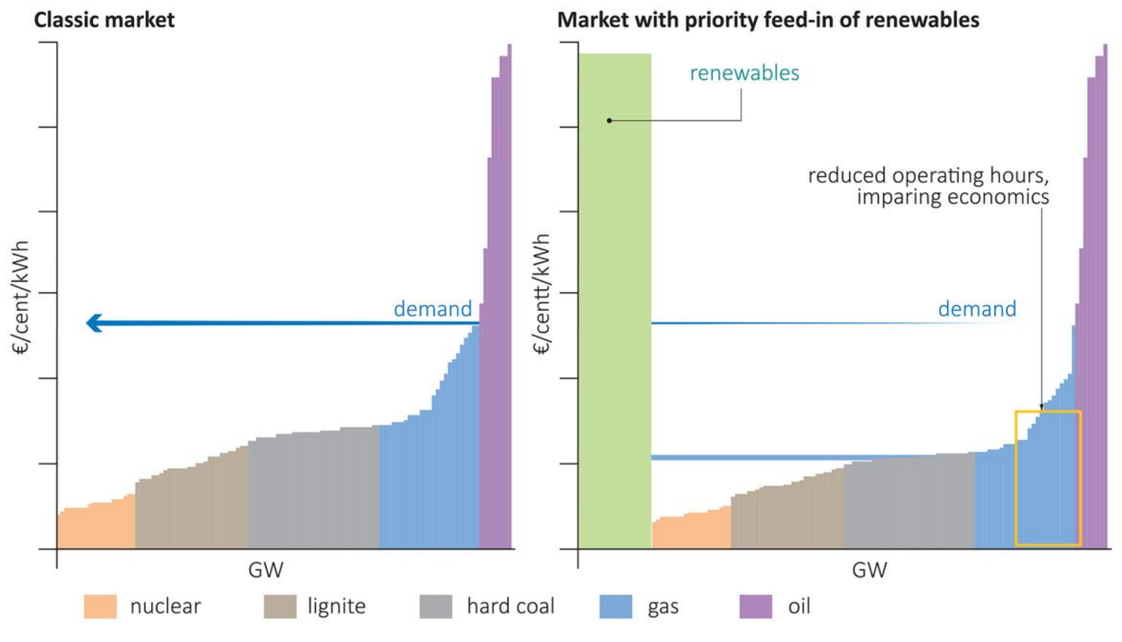

Figure 25 Consequences of the merit order distortion (Then, 2015)

In the classic market (left of Figure 25), utilities are used in order of both reliability and cost, so nuclear, lignite and coal plants are used first, with gas and oil being used to top up as necessary. As the priority feed in of renewables increases (right graph) then the baseload plants are required to run fewer hours and with increased flexibility. The economics of all systems becomes more challenging.

In Germany, coal-fired power plants are operated as 'daily start-and-stop' or 'weekly start-and-stop' to absorb daily variations and seasonal variations, which are a result of an increase in renewable energy. As mentioned in Chapter 4, there is already at least one lignite plant in Germany which can load shed or add 500 MW in 15 minutes (Fairley, 2013). Load adjustments of >50 GW (>60% of the peak load) within an 8-10-hour period have been required. This fluctuation is generally random but can be forecast up to two days in advance (commonly via the wind forecast) (Schiffer, 2014). The fluctuations can be significant – on 24 January 2013 up to 74,335 MW (92% of the peak demand of 80,739 in Germany) had to be covered by conventional power plants. Conversely, on 24 March 2013, only 14,405 MW had to be covered by conventional power stations.

Germany can counteract some of the fluctuations in demand by transferring power to and from the European grid. However, as Schiffer (2013) points out, these countries are also expanding their wind capacities and so their capacity to cover fluctuations in Germany will decline in future.

Germany has a large number of new coal and gas plants with good flexibility – there are 'very few' dedicated German baseload plants which do not allow for flexible operation (Schiffer, 2013). Load adjustments of almost 50 GW within 8 hours can be achieved. However, flexibility can be costly. As shown in Figure 26, the cost of a conventional power plant is largely capital cost which can be recuperated in the plant runs over extended periods. However, if the plant runs for fewer than 1000 hours per year then these costs increase significantly as the plant is being maintained and monitored during idling periods.

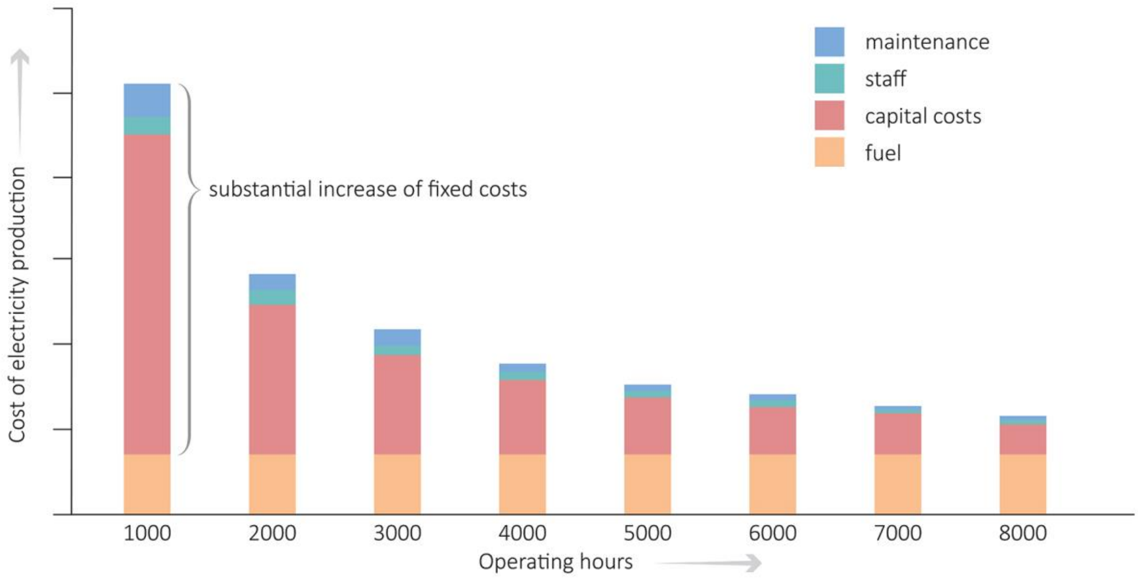

Figure 26 Lower prices and fewer operating hours decrease profitability (Then, 2015)

The number of interruptions to the German electricity grid grew by 29% between 2009 and 2012, indicating that plant flexibility was not yet ready to cope with the significant variable input from renewable systems. During the same period the number of service failures increased by over 30% and almost half of those failures led to production stoppages. These stoppages have involved damages ranging from €10,000 to hundreds of thousands of euros (Schroeder, 2012).

In 2012, several industries in Germany began to complain about the instability of the grid. Loss of grid voltage for even a second can cause production to halt in industries such as aluminium plants. This has led to companies such as Hydro Aluminium in Hamburg investing €150,000 in their own emergency power supply. The number of short interruptions in the German power supply increased by 29% between 2009 and 2012. Grid operators have so far only been required to cover up to around €5000 of related company losses to industries who have suffered mechanical damage or material loss during these incidents. Some companies have threatened to leave Germany if the problem is not solved (Schroeder, 2012).

Figure 27 shows the current and future flexibility and back-up capacity requirements in Germany.

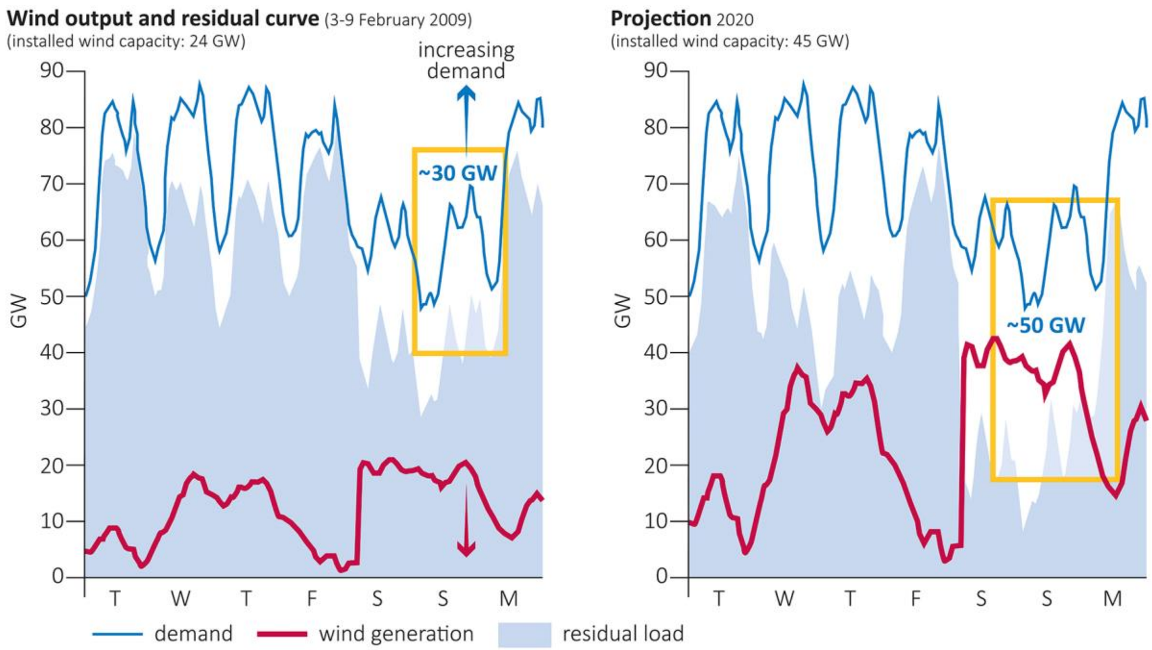

Figure 27 Current and future flexibility and back-up requirements in Germany (Eurelectric, 2011)

The graph on the left shows a situation which occurred in Germany in 2009 when the system had to cope with a load ramp of 30 GW within a few hours due to an increase in demand coinciding with a drop in wind output. The graph on the right shows what would occur should the same situation occur in 2020 – the required load ramp could reach 50 GW, which would put an incredible demand on the available dispatchable technologies such as coal.

Between 2011 and 2015, Germany opened 10.7 GW of new coal-fired power stations – these plants were all planned and approved before the Fukushima nuclear incident which caused Germany to move away from nuclear. It has been estimated that 8–12 new coal plants would be required to replace the closing nuclear fleet (Wilson, 2014). And so, although renewables are growing in Germany, the move away from coal is hardly imminent.

5.4 Comments

Different countries and regions have different levels of commitment to replacing fossil fuels with renewable options. For countries such as the USA, the level of commitment is such that some regions and generators are paying more for power and having to invest significantly in new grid infrastructure and power management systems to ensure security of supply. In other regions, such as the UK, the commitment is significantly higher and the forced move away from baseload coal is putting intense pressure on dispatchable systems such as gas and, increasingly, smaller diesel engine systems to ensure that peak power demands are met. Load shedding is also becoming increasingly common. In Germany, the ambitious move away from both nuclear and coal towards 80% renewable by 2050 is causing issues with the wholesale price of electricity. The cost of subsidies for renewable energy is eventually passed on to the consumer which means that the German population now pay several times more than the rest of the EU for power. The main electricity suppliers in Germany, Eon and RWE, are reporting significant losses in profit for continuing to supply dispatchable coal power and, despite the intended move away from coal, in reality, for the moment, coal continues to provide the majority of power on demand in Germany.

6 Conclusions

Many countries are actively moving towards more renewable energy and less fossil fuel. However, the current growth in renewable energy is happening more as a result of political will and environmental policy than from affordability. Renewable systems such as wind and solar are being given priority into many national energy grids as a result of either financial incentives or, more simply, by being defined as 'free spill' or 'must-run' technologies which the grid must accept as a priority over fossil fuel and nuclear power.

At the moment, renewable power is not entirely predictable and the intermittency in the output of wind, solar and tidal systems will remain so until the lack of affordable and scalable energy storage systems has been resolved. And so matching supply with demand becomes a balance between predicting the total combined output from intermittent renewables within a grid system, subtracting this from the expected demand curve and then making up the difference with the cheapest possible power from dispatchable sources such as gas, coal and, to a lesser extent, nuclear plants. The order in which these dispatchable systems are called upon is determined by economic merit – that is, cost. And so keeping a grid in balance is becoming more of an art of predicting outputs and availability whilst keeping costs low. Increasingly often the power demand in some regions does not match the power which is currently being supplied. Some dispatchable sources may be available relatively quickly but at cost whereas others can be produced at a slower rate, but more cheaply. There is usually some power reserve available – plants running in a relatively idling state, ready to ramp up as necessary. Whilst this flexible approach to balancing supply and demand may be somewhat challenging for a grid manager, the challenge is significantly greater for the coal plant manager who wishes to run his plant at a profit, after covering building, fuel, and operation and maintenance costs but is now being asked to do so in a manner for which his plant was not designed.

As a result of these challenges, electricity generators are changing the way they operate their plants. There is investment in newer, more flexible plants but also a change in the operation of older plants in the fleet. These older plants, with their capital costs already paid off, and which often consist of a number of smaller units, can usually operate more cheaply than newer plants. But not without consequence. It has been argued that changing plant operation reduces plant efficiency and thus increases emissions, especially CO_2, although this change is likely to be minimal. Some argue that the blame for this increase should lie with the renewable energy suppliers who are ultimately forcing this change of operation upon coal plants. However, in practice it would appear that any increase in emissions, especially of particulates, SO_2 and NOx, is minimal due to the efficiency of these pollution control systems and the skill of plant managers.

Electricity is becoming more expensive in many countries which promote renewables. Subsidies do not offset all costs and much of the cost is passed on to the consumer. Clean energy is dispatched at the top of the dispatch pile but leaves the remainder of the plants in the grid working in less than ideal conditions at reduced income. Plants making less money have less money to reinvest in maintenance and upgrading.

For a coal plant manager there is a balance to be made between occasional electricity sales, which bring in little or no profit but guarantee operation, and peak sales, which occur less often but which provide greater income per megawatt hour. But that balance has to take into account potential damage and wear and tear on the plant. Plants operating in a flexible mode show wear and tear much earlier than predicted for the same plant running at baseload. In order to avoid equipment forced outages for repair and maintenance, the plant manager must be significantly more aware of the operational conditions of his plant and the potential stresses and damage to individual pieces of equipment. Some of this damage can be monitored and predicted but this often requires increased expenditure in terms of management practices, monitoring protocols and measurement systems. A plant can avoid significant outage and repair costs by being pro-active in terms of management and monitoring, but this does not come without cost. And so it is becoming increasingly challenging for coal plant managers to determine at what point a coal plant becomes too old and too inflexible to warrant further investment, especially as investment in coal is becoming harder to find in many countries.

And so there is currently an energy dilemma – many countries wish to move away from coal towards renewables but are finding that renewables are simply not ready to provide a national baseload. Countries such as the USA are taking things relatively slowly, with some states moving faster towards renewables than others. But countries such as the UK and Germany are moving rapidly towards high percentage renewable inputs – possibly too rapidly. It would seem that the intermittency of renewables in the UK and the move away from coal is leaving the country with an exceedingly low margin of spare capacity (below 3% at peak times). In these periods the country has been calling upon gas and even upon small diesel generators to supply the missing capacity, an approach which is neither sustainable nor particularly environmentally acceptable. In Germany it seems the coal plants are being used just as much, if not more, than renewable systems at peak times and, as a result of the relatively skewed working of the subsidies and tariffs, large coal-based utilities are facing significant financial losses whilst being expected to continue to produce peak demand power for the country.

Renewable energy is probably the long-term future and fossil fuels will return to being simply fossils – eventually. But, for the moment, the rapid move towards renewables in many countries is not reducing coal output as much as would be expected and, in some regions, is actually resulting in the increased use of older, less efficient coal units to provide peak power. Whilst this guarantees and electricity supply, the additional stress on some older units may not be sustainable or desirable.

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