Operating ratio and cost of coal power generation

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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, China, the European Commission, Germany, India, Italy, Japan, Poland, Russia, South Africa, Thailand, the UAE, 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

Operating ratios are a representation of revenue and expense categories found on a typical financial statement. They are presented as a ratio or a percentage value. The smaller the operating ratio, the greater margin an organisation has to make a profit. Conversely, the greater the operating ratio is, the lower the margin to generate profit. Within operational costs, there are many factors that impact the operational efficiency of a power generating company. These include cost of fuel, staff/personnel, operation & maintenance (O&M) and depreciation and amortisation (the higher these factors are the higher the operating ratio and the lower the operational efficiency). The cost of coal-fired power generation differs not only from one country to another but also from one power plant to another. However, current coal-fired power generation is in competition with renewable energy and thus generation has shifted in many countries from baseload to load following mode necessitating flexibility in power plant operations. As such, frequent cycling of coal-fired power plants can cause thermal and pressure stresses. Over time, these can result in premature component failure and increased, necessary maintenance. Starting a unit, increasing its output, or operating at part load can also increase emissions compared to non-cyclic operation. Assessment and control of operation and plant maintenance costs play a major role in calculating operating ratios. These ratios allow a company to compare its operational performance across various times, analyse its data and take the necessary steps in order to maintain as good an operational performance as possible and as such, as low an operating ratio (%) as possible.

Acronyms and abbreviations

ADB	Asian Development Bank
AEA	American Economic Association (USA)
AEMO	Australian Energy Market Operators
AHP	Analytical Hierarchy Process
APEC	Asia Pacific Economic Cooperation
BOP	balance of plant
BTG	boiler, turbine and generator
CCGT	combined cycle gas turbine
CCS	carbon capture and storage
CCTS	carbon capture, transport and storage
CCUS	carbon capture, utilisation and storage
CDC	China Datang Corporation (China)
CEC	China Electricity Council
CHP	combined heat and power
CoE	cost of electricity
CPC	Communist Party of China
CPP	Clean Power Plan (USA)
DCF	discounted cash flow
DCOE	delivered cost of energy
DCS	digital/distributed control system
ECIU	Energy & Climate Intelligence Unit (UK)
EDF	Électricité de France SA (France)
EEX	European Energy Exchange
EFOR	equivalent forced outage rate
EIA	Energy Information Administration (USA)
EIA	Environment Impact Assessment
EOR	enhanced oil recovery
EPA	Environmental Protection Agency (USA)
EPC	engineering, procurement and construction
EPRI	Electric Power Research Institute (USA)
ERIA	Economic Research Institute for ASEAN and East Asia
ESP	electrostatic precipitation
ETI	Energy Technologies Institute (UK)
EU	European Union
FF	fabric filtration
FGD	flue gas desulphurisation
FOM	fixed operating costs
FPL	Florida Power & Light (USA)
FYP	Five-Year Plan
GE	General Electric (USA)
IEA	International Energy Agency
IER	Institute for Energy Research (USA)
IGCC	integrated gasification combined cycle
IMF	International Monetary Fund
INDCs	Intended Nationally Determined Contributions
IPCL	India Power Corporation Limited
IPP	Independent Power Producer

IRR	internal rate of return
KPI	key performance indicator
LCC	life-cycle costing
LCOE	levelised cost of energy
NDRC	National Development and Reform Commission (China)
NEA	National Energy Administration (China)
NEE	NextEra Energy (USA)
NEM	National Electricity Market (Australia)
NGCC	natural gas combined cycle
NPV	net present value
NREL	National Renewable Energy Laboratory (USA)
NTNDP	National Transmission Network Development Plan (Australia)
O&M	operation and maintenance
OECD	Organisation for Economic Co-operation and Development
OEM	original equipment manufacturers
PMC	project management consultancy
POSOCO	Power System Operation Corporation Limited, National Load Despatch Center (India)
PV	photovoltaic
PV	present value
PwC(IL)	PricewaterhouseCoopers (International Limited)
RES	renewable energy sources
ROI	return on investment
SCR	selective catalytic reduction
SBR	supplementary balancing reserve
SHR	station heat rate
TCO	total cost of ownership
TEPPC	Transmission Expansion Planning Policy Committee (USA)
TIFAC	Technology Information, Forecasting and Assessment Council (India)
UNEP	United Nations Environment Programme
UNCTAD	United Nations Conference on Trade and Development
VfS	Verein für Socialpolitik (Germany)
VOM	variable operation and maintenance
WEC	World Energy Council (UK)
WECC	Western Electricity Coordinating Council (USA)

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1 Introduction

Coal has been the cornerstone fuel of the global energy system since the industrial revolution. Today, projections, estimates and forecasts indicate that the future of coal is uncertain and its utilisation will continue to decline. This is attributed to market sources, regulations and environmental pressures. However, data as recent as 2015 shows that the second source of primary energy is coal and coal continues to be the first source of energy for power generation (Charriau and Desbrosses, 2016; IEA, 2015) (*see* Figures 1 and 2). Figure 1 highlights coal's major role in energy consumption in the G20 countries (Argentina, Australia, Brazil, Canada, China, France, Germany, India, Indonesia, Italy, Japan, Mexico, Russia, Saudi Arabia, South Africa, South Korea, Turkey, the UK and the USA) while Figure 2 shows coal continuing to dominate the power generation mix. Figure 3 shows the trend of coal consumption in the G20 countries between 2003 and 2015. Although coal consumption has declined in some parts of the world it increased in others, hence the overall growth (Charriau and Desbrosses, 2016). Demand for coal-fired power generation is expected to continue, especially in developing countries, with a focus on improving the standard of life.

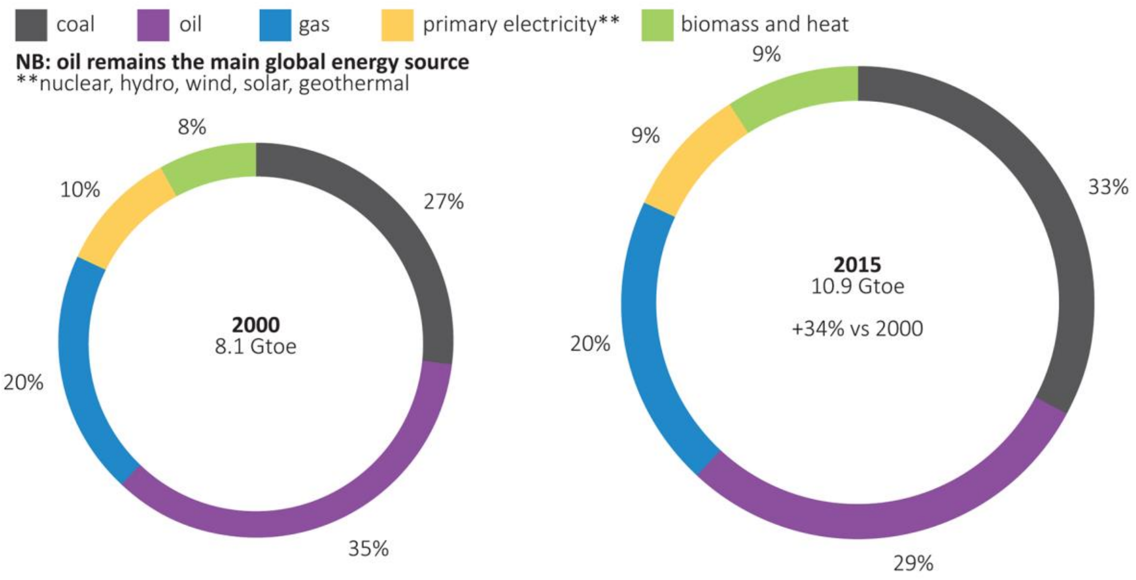


Figure 1 Primary energy consumption for the G20 countries in 2000 and 2015 (Charriau and Desbrosses, 2016)

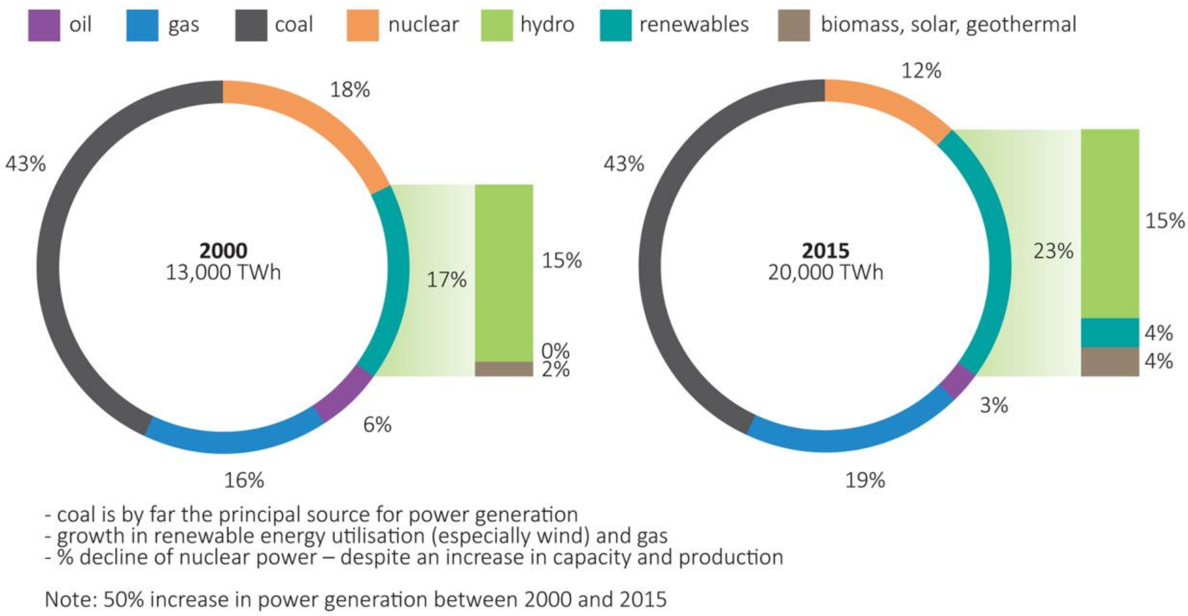


Figure 2 The distribution of power generation by fuel in 2000 and 2015 in the G20 countries (Charriau and Desbrosses, 2016)

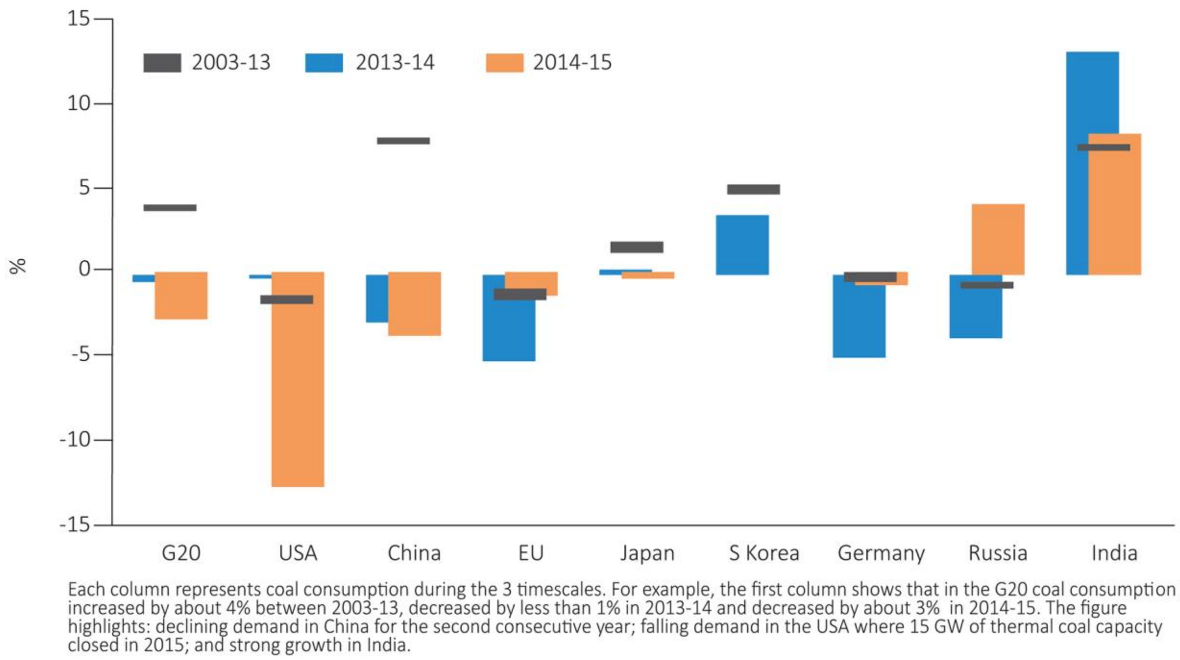


Figure 3 Trends in coal consumption in the G20 countries, %/y (Charriau and Desbrosses, 2016)

It is worth noting here that within the framework of its *World Energy Outlook*, IEA (2015) has been measuring and analysing fossil-fuel subsidies for more than a decade. The analysis aims to demonstrate the impact of fossil-fuel subsidy removal for energy markets, climate change and government budgets. The IEA's latest estimates indicate that fossil-fuel consumption subsidies worldwide amounted to US$493 billion in 2014 (four-times the value of subsidies for renewable energy). Since 2009 the IEA has provided input to the G20 and Asia Pacific Economic Cooperation (APEC) in support of their commitments to 'rationalise and phase out over the medium-term inefficient fossil-fuel subsidies that encourage wasteful consumption'. According to the IEA (2015), many countries are now pursuing reforms, but steep economic, political and social hurdles will need to be overcome to realise lasting gains. If and when such reforms are instigated, they will impact not only coal-fired power generation but the role of coal, oil and gas in providing primary energy and power. The IEA (2015) advocates phasing out the remaining fossil-fuel subsidies to end-users by 2030 and progressively reducing the use of the least-efficient coal-fired power plants and banning the construction of new inefficient facilities.

On 17 November 2015, Export Credit Group of the Organisation for Economic Co-operation and Development (OECD) reached an agreement on new rules on official support for coal-fired power plants, including restrictions on official export credits for the least efficient coal-fired power stations. The agreement will come into force in January 2017, and is subject to a mandatory review in 2019. The new agreement encourages both exporters and buyers to move away from low efficiency towards high efficiency technologies. The agreement removes support for large supercritical and subcritical plants but allows support for smaller subcritical plants in poorer, developing countries. It also allows support for up to medium size supercritical power plants in countries facing energy poverty challenges. The new rules distinguish between large- (>500 MW), medium- (≥300 to 500 MW), and small- (<300 MW) plants; technology types (ultrasupercritical; supercritical; and subcritical), and the levels of development of the project country. Restrictions on support will not apply to any plants equipped with operational CCS, as provided under the existing climate sector understanding (OECD, 2015).

Another factor that may impact fossil-fuel power generation, in the long term, is the advent and uptake of distributed generation. Distributed generation is the use of small-scale technologies to produce electricity close to the end users of the power. These technologies often consist of modular, and sometimes renewable-energy, generators and use numerous, small plants that can provide power onsite with little reliance on the distribution and transmission grid. Distributed generation technologies yield power in capacities that range from a fraction of kW to ~100 MW. Utility-scale coal-generation units generate power in capacities that can exceed 1000 MW.

However, despite the above, Nalbandian-Sugden (2015) in a review on regulatory trends and their impact on coal demand and coal in power generation summarised her findings as follows: *in the short- to medium-term, demand for thermal coal will continue to grow.* The pace of growth will moderate gradually until demand eventually peaks and then plateaus. If carbon capture and storage (CCS), for coal-fired power plants, becomes available at competitive cost, the outlook could change in favour of coal. This is due to the abundance of coal and the proven history, availability, reliability and advancements in coal-fired power generation technology. However, without CCS, the current long-term outlook for coal-fired power generation is less certain. This is mainly due to environmental pressures (especially climate change) and greater competition from renewables and natural gas.

It must be noted though that non-dispatchable technologies, such as wind and solar power, provide energy to the grid but as their output is variable do not provide sufficiently reliable energy to be considered as capacity. Currently, renewables cannot be relied upon to meet peak energy demand under certain weather conditions (for example, no sun and/or no wind). As such, there are those who consider that renewable energy should pay a capacity charge back into the system to cover the cost of constructing and operating the back-up technology required, such as fossil-fuel power plants, when intermittent, renewable energy is unavailable (IER, 2012). Without such a step, the additional cost of providing flexible power is carried by other technologies and energy providers, such as coal-fired power plants.

Electricity generation technologies all have advantages and disadvantages. According to EPRI (2012), renewable technologies such as solar and wind use 'free' resources and don't produce greenhouse gas emissions, but are not always available when needed and require significant amounts of land. Technologies such as coal and nuclear power produce electricity in large quantities, reliably and continuously, but coal combustion produces significant greenhouse gas emissions and in the case of nuclear power generation, considerable waste disposal issues. Figure 4 gives an assessment of relative benefits/impacts of the power generating technologies available today and differences in their construction cost, electricity cost, land use, water requirements, CO_2 emissions, non CO_2 emissions, waste products as well as the availability and flexibility of these technologies (EPRI, 2012)

Figure 4 Assessment of relative benefit/impact of coal, coal with CCS, natural gas, nuclear, hydro, wind, biomass, geothermal and solar photovoltaic electricity generating technologies (EPRI, 2012)

This review presents the concept of operating ratio in coal-based power generation but due to the lack of information in the public domain and the proprietary nature of the material, this report focuses on the cost of pulverised coal power generation, and at the plant only. The cost structure for transmission and distribution is different than for power generation, since there is basically no fuel cost involved with operating transmission and distribution wires (and their associated balance of systems, such as substations). At the margin, there is no cost of loading a given transmission line with additional electricity (unless the line is operating at its rated capacity limit). Capital cost thus dominates the economics of transmission and distribution (Blumsack, 2014).

Economics, have been and still are the main driver in the selection of a power generation scheme for a given situation. Return on Investment (ROI), in today's climate, is a most important factor that justifies any investment decision including that of constructing a new or operating an existing coal-fired power plant. If a measurable profit or, in some regions, benefit to the economy or standard of life, can be demonstrated; private, national and international investors will be interested in becoming involved in such endeavours. Nevertheless, running a power plant in itself requires electricity. Fuel preparation, lighting, air conditioning and water treatment are some of the auxiliary power consuming operations that are indispensable and can account for between 4% and 15% of a power plant's entire output. Therefore, electricity saved by improving these auxiliary systems efficiencies will result in greater ROI by generating more electricity to sell and as such greater revenue. For a detailed study on the design of auxiliary systems in fossil-fuel power plants *see* ABB (2009).

Operating ratios are calculated in Chapter 2 for a number of major power generating companies to indicate their operational efficiency year on year (on average, 2013 to 2015) and, to show where the operating ratio improved and/or deteriorated. The operating ratios of the companies ***must not*** be compared as the information provided in the consolidated financial statements used for the calculations differs from one corporation to another. Chapters 3 and 4 cover the economics and costing of coal power generation including capital costs, operation and maintenance (O&M) costs, the levelised cost of electricity (LCOE), the parameters that influence these costs as well as a cost analysis section which includes CCS costing. What the future holds for coal is discussed in Chapter 5.

2 Operating ratio

Operating ratios are a representation of revenue and expense categories found on a typical financial (profit and loss) statement. They are presented as a ratio or a percentage value. The revenue ratios are a per cent of total revenue and the expense ratios are also a percent of total revenue. As such, revenue ratios total 100%; expense ratios may or may not. Expense ratios totalling less than 100% denote an operating surplus. Those totalling more than 100% denote an operating deficit. In the case of deficits, a power company would either draw on reserves or carry the deficit as debt into the next fiscal year. In simple terms, the operating ratio in the context of this review is power generation operating expenses to revenue. An operation ratio is usually given in percentage terms.

The ADB (2011) defines operating ratio as operating expenses (such as fuel, operation and maintenance, depreciation and staff/personnel expenses) as a percentage of total revenue. To clarify, operating ratio in power generation is a ratio that shows the efficiency of a power generating company's management by comparing *operating expenses* to *net sales (revenue)*. Meaning, the smaller the operating ratio, the greater margin an organisation has to make a profit. Conversely, the greater the operating ratio is, the lower the margin to generate profit. The formula for calculating operating ratio is therefore:

$$\text{Operating ratio} = \text{Operating expenses} / \text{revenue or sales} * 100$$

Operating ratio provides information about the condition of the power sector assets. This information is important by itself, as it reflects the burden of assets that are not utilised for both the power sector and the fiscal system. In addition, it provides context to the analysis of other efficiency indicators, such as *load factor* and *capacity factor.* The operating ratio indicator is important in that it highlights where quantity and quality of power supply are problematic, both of which are directly related to the condition of the sector assets. It also points to cases, in which non-operational assets might create fiscal problems.

The *load factor* is simply the ratio of average demand over maximum demand and it plays a vital role in determining the cost of energy. Advantages of a high load factor include (Mehta and Mehta, 2005):

- A high load factor results in a reduction in cost per unit generated. The higher the load factor, the lower the generation cost. That is because a higher load factor means that for a given maximum demand, the number of units generated is more and hence the generation cost per unit is lower.
- A high load factor reduces variable load issues on the power station. A higher load factor means comparatively fewer variations in the load demands at various times. This avoids the frequent use of regulating devices installed to meet variable loading on the station.

The *capacity factor* is simply the ratio of actual power generation (that is the average demand) over a time period (typically a year) divided by the installed capacity. On average, the capacity factor for coal-fired power plants is ~60-70%. In other words, the ratio of a unit's actual output to its maximum possible output at its rated capacity is called capacity factor. For example, a 300 MW unit where output is 400 MWh over two hours, the unit would have a capacity factor of 400 MWh divided by 300 MW x 2 hours, or 600 MWh, which would be its maximum output. So the capacity factor of the unit for those two hours is 67%. Basically, the capacity factor is used to determine how fully a unit's capacity is utilised (Shively, 2012).

Clear and precise financial operating ratio data is commercially sensitive, making it somewhat difficult to find such information in the public domain. In addition, power company statistics are not published specifically for coal utilisation as such. In general, power generating companies tend to provide general data (grouped/rounded, that is including all types of power systems operated by the company) in their financial performance statements (annual reports), including *total* sales/revenue and operating costs for coal, gas, nuclear or any other source of energy utilised. The following section presents the financial performance and, where possible, operating ratios for twelve major power generating companies in 2014 and 2015.

Note that the operating ratio, which is viewed as a measure of operational efficiency, is only useful for indicating whether the core business is able to generate a profit. Since several potentially significant expenses, such as taxes or interest payments, are not included, it is not a direct indicator of the overall performance of a business, and so can be misleading if and when used without any other performance metrics. For example, a company may be highly leveraged and must therefore make substantial interest payments that are not considered part of the operating ratio. Furthermore, operating ratios depend on expense levels, which tend to differ by region in a country because of such items as type of power available (fossil, nuclear, hydro) and personnel costs. Therefore, comparisons of operating ratios tend to be most useful when they are made within regions. Finally, if and when comparing operating ratios between companies, it is critically important that the comparison is for companies in the same industry, in the same country and companies that are subject to similar financial conditions. If a company has a higher operating ratio than its peer average, it is an indication of operational inefficiency, and vice versa. However, it should be kept in mind that some companies may have taken on substantial debt which may involve higher interest payments, which are not included in the operating ratio calculation. Two companies may have the same operating ratio but different debt levels, so it is important to compare debt ratios before coming to any conclusions.

In another context, operating ratio is a terminology used to indicate the ratio of operating to installed capacity. In this context, the *capacity operating ratio* measures actual capacity of the power system as compared with nominal capacity and usually is expressed in percentage terms. The higher the percentage term in this context the better the performance of the sector or the power provider. The formula for calculating capacity operating ratio is: Operating ratio = Operating capacity (MW) / Installed capacity (MW) * 100 (Tallapragada and others, 2009). This review discusses the financial operating ratios and *not* the capacity operating ratios.

2.1 Power companies and operating ratios

Platts (2016) lists the top 20 companies utilising *all fuels* and sources for power generation (*see* Table 1), as of March 2016, by their total capacities (GW). Table 2 lists the top 20 companies using ***coal*** as the combustion fuel, also as of March 2016, by their total generating capacities (GW) (Platts, 2016).

Table 1 Top 20 power generating companies using *all fuels*/sources and their total (operating) generated capacity in GW (Platts, 2016)

Power generating company	Capacity, ~GW
China Huaneng Group Corporation	157
EDF Group	130
China Datang Corporation	128
China Guodian Corporation	117
China Huadian Group Corporation	113
State Power Investment Corporation	91
Korea Electric Power Corporation	78
Enel spa	77
ENGIE	76
Duke Energy Corporation	63
NRG Energy Incorporated	57
Saudi Electric Company	55
Tokyo Electric Power Company	55
Shenhua Group Corporation	54
Southern Company	51
Comisión Federal de Electricidad	46
NextEra Energy Incorporated	46
China Resources Power Holdings	45
Eskom Holdings SOC Limited	45
E.ON SE	43

Table 2 Top 20 power generating companies using coal as combustion fuel and their total (operating) generated capacity in GW (Platts, 2016)

Power generating company	Capacity, ~GW
China Huaneng Group Corporation	130
China Guodian Corporation	109
China Datang Corporation	104
China Huadian Group Corporation	87
State Power Investment Corporation	70
Shenhua Group Corporation Limited	62
NTPC Ltd	53
China Resources Power Holdings	47
Eskom Holding SOC Limited	46
Korea Electric Power Corporation	36
Guangdong Yudean Group Company Limited	32
NRG Energy Incorporated	23
Southern Company	21
American Electric Power Company Incorporated	21
Duke Energy Corporation	19
RWE AG	18
Enel spa	18
DTEK	16
PT PLN Persero	16
State Development Investment Corporation	15

Finding annual reports for some of the companies listed in Table 1 and 2 in the public domain has not been possible. Hence, the following operating ratio calculations are based on the power-technology.com (2014) profile of ten of the world's biggest power companies in 2014. The size is determined by Forbes calculation of net market capitalisation, assets, sales and profit. The annual reports of these companies are available in the public domain. Two major power generating companies in China and India have been included. The companies studied are EDF (France), Enel (Italy), E.ON/Uniper (Germany), Iberdrola (Spain), Duke Energy (USA), Exelon (USA), Southern Company (USA), NextEra Energy (USA), Dominion Resources (USA), SSE (UK), China Datang Corporation (China) and NTPIC (India). The operating ratios were calculated in this review from these companies' annual reports, mainly for the year 2015. The exercise was undertaken simply to indicate the year-on-year operational efficiency of these companies and, to show where the operating ratio improved and/or deteriorated*. **The operating ratios must not be compared between the different companies as the information provided in the consolidated financial statements differs from one power supplier to another in that there is no breakdown of exact operating costs especially where it is unclear whether staff/personnel costs were included or not.***

2.1.1 Électricité de France SA (EDF)

Électricité de France SA (EDF) is a French state-owned company. EDF was founded in 1946 and its headquarters are in Paris. Gross installed capacity of the company by the end of 2013 stood at 140 GW, which included 28.6% from coal and 53% from nuclear power. It generated 653.9 TWh of electricity during the year 2013. EDF Energy's coal generation assets are Cottam (2 GW) and West Burton A (2 GW) power stations in the UK. In the year ended 31 December 2014, the two plants generated 19.8 TWh of electricity. The plants also had two major outages.

In EDF Energy's annual review for the year ending December 2014, the consolidated income statement gives the total revenue for 2013 and 2014 as £8,311 million and £8,159 million, respectively. The operating costs (operating expenses including personnel and other, depreciation and expenditure on major inspection and overhauls of plant and equipment) for the years 2013 and 2014 were given as £7,468 million and £7,488 million, respectively, in total. The consolidated operating ratio therefore for EDF Energy was about 90% for 2013 and 92% for 2014, indicating that the company operational efficiency reduced by approximately 2% in 2014 compared to 2013 (EDF Energy, 2014).

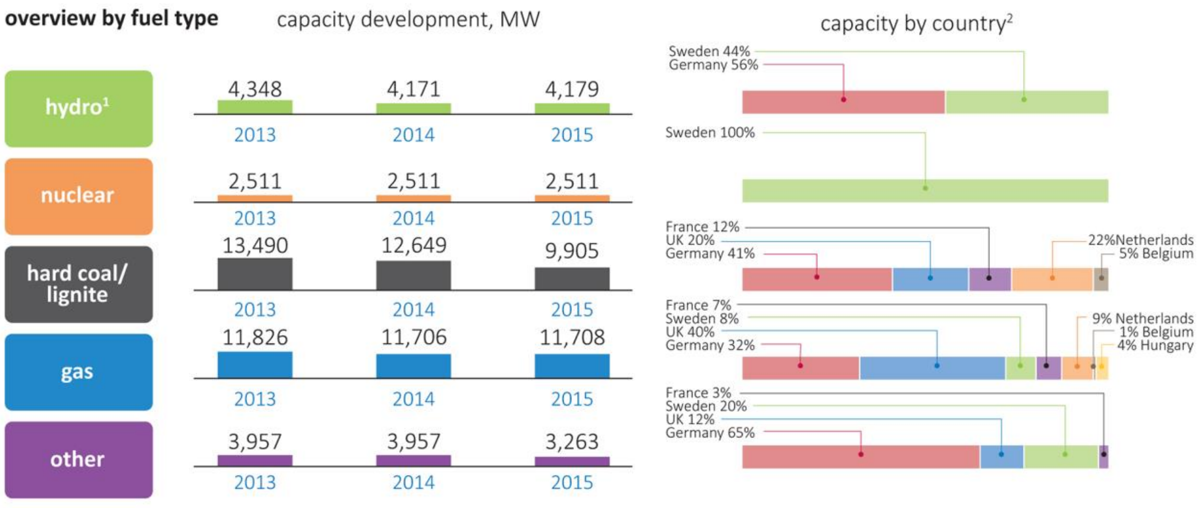
2.1.2 Enel

Enel (Italy), with headquarters in Rome, is a multinational producer and distributor of electricity and gas. It was founded as a state owned company in 1962 and privatised in 1999. In 2015, the State owned 25.5% of the company. Net electricity generated internationally by Enel Group in 2014 rose by 1.3 TWh (+0.5%) at 283.1 TWh compared to 2013, with an increase in generation in Italy (+0.6 TWh) (71.8 TWh) and abroad (+0.7 TWh) (211.3 TWh). The increase, attributed to renewable energy generation (+3.6 TWh) (94.9 TWh) due to an expansion of installed capacity and favourable weather conditions, was offset by a reduction in nuclear generation (-1.3 TWh) and in thermal generation (-1.0 TWh), attributed to the shut-down of a number of plants in Latin America. However, thermal generation (mainly coal-based) in Italy increased by 483 GWh. In 2014, gross thermal generation of Enel in Italy amounted to 45,904 GWh of which 37,146 GWh was coal-based (that is, 81%). In total, coal contributed 17,048 MW (~18%) toward the net electric generated capacity by Enel in all countries.

In its 2014 annual report, Enel (2015) gives the gross revenue for the group as €75,791 million, a decrease of €2,872 million (-3.7%) on 2013. The decline is essentially attributed to the decrease in revenue from the sale of electricity. Enel uses the indicator 'operating margin', which is another measure of profitability. It indicates, in the context of this review, how much of the revenue is left over after both costs of power generated and operating expenses are considered. The gross operating margin in 2014 amounted to €15,757 million, down 5.6% compared with 2013 (€16.691). Gross operating costs for the year 2014 were €60,034 and €61,972 for the year 2013. As such, the operating ratio for the Enel group therefore was about 78.8% for 2013 and 79.2% for 2014, indicating that the company operational efficiency reduced but only by a small margin of approximately 0.4% in 2014 compared to 2013 (Enel, 2015).

2.1.3 Uniper Group (E.ON)

E.ON is a privately-owned, German energy group formed in June 2000 following the merger of the two companies, VEBA and VIAG, which were founded in the 1920s and privatised in the 1960s and 1980s. On 1 January 2016, E.ON separated its operations into two independent companies; E.ON and Uniper (E.ON, 2016). Uniper's portfolio combines large-scale power generation and the management of global and regional energy supply chains while E.ON focuses on renewable energy, distribution networks and customer solutions. As such, the operating ratio for Uniper's financial performance will be used for the calculations in this review. Uniper has its headquarters in Dusseldorf and a portfolio of conventional assets with emphasis on gas-fired power plants and global energy trading. Uniper's generation fleet includes about 40 GW of capacity in Europe and Russia (*see* Figure 5). Figure 5 shows that the largest Uniper supplied capacity and country spread in 2013 was based on power generation with lignite/coal. However, in 2015, although gas-fired power generation appeared to surpass coal and take first place in the mix, the total gas-fired capacity remained about the same. The decrease in coal-fired power generation was due to improved efficiency and a reduced demand for electricity. The fleet includes the new, unit 3, state-of-the-art coal-fired power generating unit at Maasvlakte power station outside Rotterdam (Netherlands), which entered service in 2015. Several Uniper power plants also produce heat for district-heating systems as well as process steam, compressed air, and other services for nearby industrial facilities (Uniper, 2016a,b,c).



[1] capacity development includes net generation capacities from Hydro LTCs in Austria and Switzerland of 820 MW in 2013, 629 MW in 2014 and 629 MW in 2015: capacity by country does not include Hydro LTCs, net generation capacity is reported for a power plant if it has been in operation within a year
[2] based on 2015 (accounting view)

Figure 5 Uniper generating capacity development by fuel (MW by year and % by country) (Uniper, 2016b)

Gross installed capacity of the company by the end of 2015 was 41 GW, which included 11.93 GW capacity (~29%) generated with hard coal/lignite (>45 TWh). The Uniper Group combined statement of income as reported in 2016 (Uniper, 2016) gives the total revenue for 2013, 2014 and 2015 as €99,322 million, €97,687 million and €102,940 million respectively. The operating costs (operating expenses including cost of materials, personnel, depreciation and other operating expenses) for the years 2013 and 2014 were given as €99,971 million and €100,358 million and €106.447 million respectively, in total. The consolidated operating ratio therefore for Uniper Group was about 100.65% in 2013, 102.73% for 2014 and 103.41% for 2015, indicating that the company operational efficiency reduced by approximately 2% in 2014 compared to 2013 and again by a further ~1% in 2015 compared to 2014 (Uniper, 2016a,b,c).

2.1.4 Iberdrola

Iberdrola is a Spanish-multinational company with headquarters in Bilbao (Spain). Its core business is related to the generation, transmission, distribution and sales of electricity. The company operates not only in Spain but also in the UK and Latin America, where it has an installed capacity of >6.6 GW in Mexico and Brazil. In addition, Iberdrola has a presence in North America, due to the potential growth there in renewable energy. Currently, the company has a project portfolio of approximately 6.5 GW in the USA. At the end of 2015, Iberdrola had >46 GW installed capacity worldwide (generating ~214 TWh) of which only ~2% was coal-based (Iberdrola, 2016).

The independent audit report of the consolidated financial statements for Iberdrola Group income as reported in 2016 (Ernst & Young, 2016) gives the net revenue for 2015 and 2014 as €31,419 million and €30,032 million respectively. The operating costs (operating expenses including procurements, staff costs, depreciation and amortisation, and provisions) for 2015 and 2014 were given as ~€24,483 million and ~€23,196 million respectively, in total. The consolidated operating ratio therefore for Iberdrola Group was about 77.9% for 2015 and for 2014 it was approximately 77.2%, indicating that the company operational efficiency reduced by a small margin of 0.7% in 2015 compared to the year 2014 (Ernst and Young, 2016). In its annual report 2015, Iberdrola considers that the coming decades will see a power generation scenario marked by a 40% increase in energy demand through 2040 constricted by the commitments resulting from the Climate Change Conference (COP21) held in Paris (*see* Nalbandian-Sugden, 2015). As such, the energy mix must change substantially and the consumption of fossil fuels must reduce. The technologies considered for further development in the coming years are those that are sufficiently mature to provide large-scale solutions at a reasonable cost, including hydroelectric systems, with a 60% increase in the next 25 years, and onshore and offshore wind energy. According to Iberdrola (2016), an investment of approximately US$7 trillion will be needed in OECD countries (US$13 trillion in non-OECD countries) through 2040 to satisfy the growing demand for electricity and to meet the goals of global energy policies (Iberdrola, 2016).

2.1.5 Duke Energy

Duke Energy is an electric power company with headquarters in Charlotte, North Carolina (USA). The company owns and operates regulated and non-regulated plants in the USA and Latin America through two segments: regulated utilities and international energy. The regulated utilities segment generates, transmits, distributes, and sells electricity using coal, hydro, natural gas, oil, and nuclear fuel. The regulated utilities produce approximately 50.2 GW of capacity. The international energy segment operates and manages power generation facilities in Latin America; and markets and sells electric power, natural gas, and liquid natural gas. In Latin America, Duke Energy's primary assets include approximately 4.9 GW of hydroelectric and thermal generating capacity. The regulated utilities and international energy generation fuel mix and net output in GWh are shown in Figure 6. Another segment is the commercial portfolio one, which acquires, builds, develops, and operates wind and solar renewable generation and energy transmission projects.

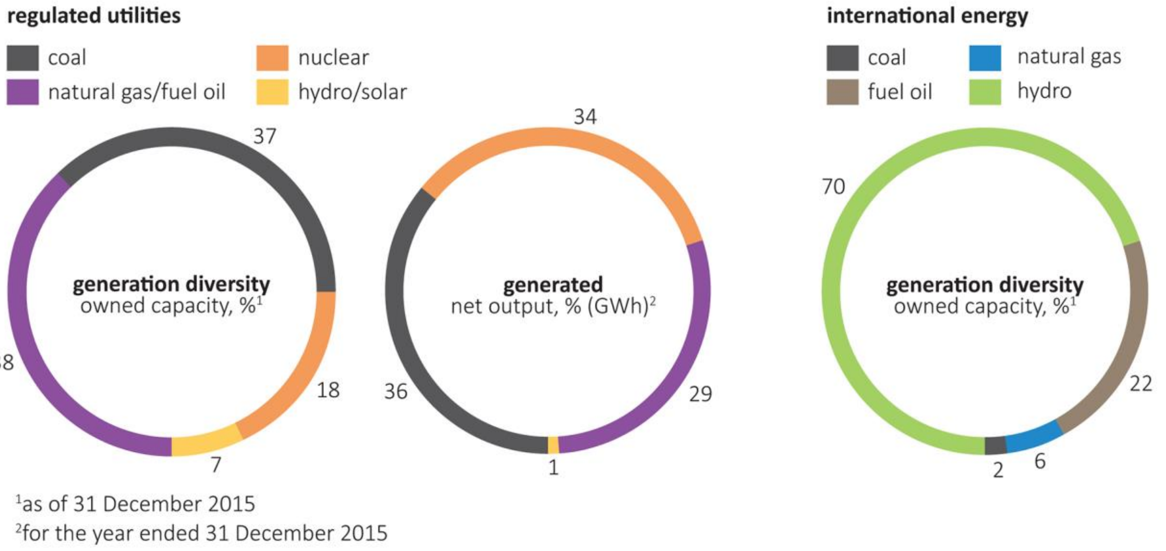


Figure 6 Duke Energy regulated utilities and international energy generation fuel mix and net output in GWh (Duke Energy, 2016)

The Duke Energy Corporation consolidated statement of operations gives the total operating revenues for 2015, 2014 and 2013 as US$23,459 million, US$23,925 million and US$22,756 respectively. The operating costs/expenses (including fuel, operation, maintenance and 'other costs' and, depreciation and amortisation for the years 2015, 2014 and 2013 were given as US$16,872 million, US$17,389 million and US$16,213 million respectively, in total. Please note that it is not clear from the statement whether staff/personnel costs are included in the operating costs but for the purposes of this review the operating ratios will be calculated as though staff/personnel costs are included in the 'other costs'. The consolidated operating ratio therefore for Duke Energy Group was about 71.9% for 2015, 72.7% for 2014 and it was approximately 71.2% for 2013, indicating that the company operational efficiency improved by a margin of 0.8% in 2015 compared to the year 2014 but did not achieve the same operational efficiency it attained in the year 2013 (Duke Energy, 2016).

2.1.6 Exelon Corporation

Exelon Corporation is a utility services company with headquarters in Chicago (USA). The company engages primarily in the generation of electricity from nuclear, fossil, hydro, and renewable energy sources. As of 31 December 2015, Exelon's generation exceeded 32.7 GW of owned capacity in 18 states and Canada but the company has operations and activities in 48 US states, the District of Columbia and Canada. Exelon utilities include BGE (Baltimore Gas and Electric, with headquarters in central Maryland), ComEd (Commonwealth Edison, with headquarters in northern Illinois) and PECO (formerly the Philadelphia Electric Company, with headquarters in south-eastern Pennsylvania). Total power delivered by Exelon in 2015 was 194 TWh (Exelon, 2016a,b).

The Exelon Corporation consolidated statements of operations and comprehensive incomes gives the total operating revenues for 2015, 2014 and 2013 as US$29,447 million, US$27,429 million and US$24,888, respectively. The operating expenses (including fuel, operation and maintenance and, depreciation and amortisation for the years 2015, 2014 and 2013 were given as US$23,856 million, US$23,885 million and US$20,147 million respectively, in total. Please note that it is not clear from the consolidated statements whether staff/personnel costs are included in the operating costs but for the purposes of this review the operating ratios will be calculated as though staff/personnel costs are included in operation and maintenance costs. The consolidated operating ratio therefore for the Exelon Corporation was about 81% for 2015, 87% for 2014 and approximately 81% for 2013, indicating that the company operational efficiency improved by a margin of 6% (in operating ratio) in 2015 compared to the year 2014, and achieved the same operational efficiency (that is, operating ratio) it had in the year 2013 (Exelon, 2016a).

2.1.7 Southern Company

Southern Company is a US energy company based in Atlanta (GA) with approximately 44 GW of generating capacity utilising nuclear, coal, natural gas and renewable energy as well as promoting energy efficiency. AGL Resources, also based in Atlanta, is an energy services company, which also owns and operates natural gas facilities and services. Southern Company and AGL Resources merged in July 2016 and, as such, have created the second-largest utility company in the USA by customer base. The merger brought together eleven regulated electric and natural gas distribution companies. For more information on the merger, visit www.doingenergybetter.com.

A condensed statement of income for the electricity business only for Southern Company gives the total electric operating revenues for 2015 as US$17,442 million and US$18,406 for the year 2014. The electric operating expenses (including fuel, other operations and maintenance and, depreciation and amortisation for the years 2015 and 2014 were given as US$11,062 million and US$12,375 million, in total, respectively. Please note that it is not clear from the condensed statement whether staff/personnel costs are included in the operating costs but for the purposes of this review the operating ratios are calculated as though staff/personnel costs are included in other operation and maintenance costs. The operating ratio therefore for the electricity business of Southern Company was about 63% for 2015 and approximately 67% for 2014, indicating a company operational efficiency improvement of 4% in 2015 compared to 2014 (Southern Company, 2016).

2.1.8 NextEra Energy (NEE)

NextEra Energy (NEE) is an electric power company with headquarters in Juno Beach, FL (USA). NextEra Energy's principal subsidiaries are Florida Power & Light Company (a rate-regulated electric utility) and NextEra Energy Resources, which is a generator of renewable energy. NEE has electric generation facilities located in 27 states in the USA and 4 provinces in Canada. The company's generating capacity is approximately 46.4 GW. NEE also owns generation, transmission and distribution facilities to support its services. NEE's business strategy emphasises the development, acquisition and operation of renewable, nuclear and natural gas-fired generation facilities. Approximately 97% of the company generation fleet, measured by MWh produced, comes from renewable, nuclear and natural gas-fired facilities. At the end of December 2015, FPL owned and operated 70 fossil-fuelled units, primarily natural gas, and had a joint ownership interest in three coal-fired units. Combined, the fossil-fuelled fleet provided 21,766 MW of generating capacity. These units are out of service from time to time for routine maintenance or on standby during periods of reduced electricity demand. St Johns River Power Park (FL) coal-fired units 1 and 2, in which FPL has a 20% joint ownership interest, have firm coal supply and transportation contracts for all of their fuel and transportation needs through 2017. Scherer (GA) unit 4, another coal-fired unit in which FPL has a 76% joint ownership interest, has firm coal supply contracts for a portion of its fuel needs through 2016, and transportation contracts for all of its needs through 2019 and a portion of its needs through 2028. Any of the remaining fuel requirements for these coal-fired units, as well as for the 250 MW coal-fired Cedar Bay (FL) generation facility purchased in September 2015, will be obtained in the spot market (NextEra Energy, 2016).

The consolidated statements of income for NextEra Energy give the total operating revenues for 2015 as US$17,486 million, US$17,021 for the year 2014 and US$15,136 for the year 2013. The operating expenses (including fuel, other operations and maintenance and, depreciation and amortisation for the years 2015, 2014 and 2013 are given as US$11,427 million, US$11,302 million and US$10,315 million, in total, respectively. Please note that it is not clear from the condensed statements whether staff/personnel costs are included in the operating costs but for the purposes of this review the operating ratios are calculated as though staff/personnel costs are included in other operations and maintenance costs. The operating ratio therefore for the electricity business of NextEra Energy for the year 2015 was about 65%, 66% for the year 2014 and approximately 68% for the year 2013, indicating that the operational efficiency of NextEra Energy operations has improved year on year since 2013, albeit by a small margin of 1% from the year 2014 to the year 2015 and 3% from the year 2013 to 2014 (NextEra Energy, 2016).

2.1.9 Dominion Resources

Dominion Resources Inc. is a producer and transporter of energy with headquarters in Richmond (VA, USA). The company operates approximately 24.3 GW of electricity generating capacity, 34,200 miles (55,000 km) of natural gas transmission, distribution, gathering and storage pipeline and 63,800 miles (103,000 km) of electric transmission and distribution lines. Dominion's power generating fleet includes facilities powered by nuclear, coal, natural gas, oil and renewable resources, including biomass, solar, hydro and wind. In 2015, 32% of Dominion Virginia Power's net electric production came from coal, and 28% from natural gas. As part of a move to cleaner energy, Dominion has closed several coal power plants or converted them to natural gas. In addition, new US EPA rules released in 2015 require all energy providers nationwide, including Dominion, to close coal ash ponds at some of these facilities (Dominion Resources, 2016). The rules set new standards for siting of new coal ash tanks to protect local groundwater supplies, as well as higher structural integrity standards for new and existing coal ash ponds and landfills.

The consolidated financial statements of income for Dominion Resources give the total operating revenues for 2015 as US$11,683 million and US$12,436 for the year 2014 and US$13,120 for the year 2013. The operating expenses (including fuel, other operations and maintenance and, depreciation and amortisation for the years 2015, 2014 and 2013 are given as US$7,266 million, US$8,812 million and US$8,883 million, in total, respectively. Please note that it is not clear from the consolidated statements whether staff/personnel costs are included in the operating costs but for the purposes of this review the operating ratios are calculated as though staff/personnel costs are included in other operations and maintenance costs. The operating ratio therefore for Dominion Resources operations for the year 2015 was 62%, about 71% for the year 2014 and approximately 68% for the year 2013, indicating that the operational efficiency of Dominion Resources operations improved by a margin of 9% in 2015 compared to 2014, although it had deteriorated by a margin of 3% in 2014 compared to 2013 (Dominion Resources, 2016).

2.1.10 SSE

SSE is a UK company based in Perth. It is involved in producing, distributing and supplying electricity and gas, as well as other energy-related services, to homes and businesses in the UK and Ireland. SSE has invested in renewable energy to support the transition to a low carbon electricity system. The electricity generation mix increased by 12% between 2014/15 and 2015/16 for renewables whilst coal reduced by nearly 33% in the same period. SSE plans to reduce the carbon intensity of its electricity generation output by 50% by 2020, using 2006 performance as its baseline. Output from SSE's coal-fired generation plants dropped from 9,143 GWh to 6,141 GWh between 2014/15 and 2015/16. In 2015/16 the UK Government announced a number of policies and regulatory changes affecting all thermal generation plants. These included an intent to close coal-fired power stations by 2025, and facilitate the development of new gas-fired power stations. In 2004, SSE acquired two coal-fired power stations; Ferrybridge in Yorkshire (now closed) and Fiddler's Ferry in Cheshire (1995 MW). In March 2016 SSE ceased coal-fired electricity generation at Ferrybridge and is now in the process of decommissioning the plant, in line with the announcement of plans to do so in May 2015. In March 2016 Fiddler's Ferry secured a contract to provide ancillary services to the National Grid. The one-year contract, which started on 1 April 2016, covers one of the three available units at the site. Furthermore, a decision was made that one unit at the station will provide supplementary balancing reserve (SBR) services to the National Grid for the winter of 2016/17. On the other hand, in November 2015 the 735 MW Keadby, mothballed, gas-fired power station returned to service to contribute to the UK electricity system. SSE continues to move from a coal and gas weighted portfolio towards one comprised largely of gas and renewables. In 2015, the share of low carbon electricity in the generation mix in the UK reached a record high of 45.5% (up ~ 8% on 2014), due to nuclear generation and higher renewables generation capacity (SSE, 2016).

The consolidated income statement for SSE plc for the year ended 31 March 2016 gives the total revenues for 2016 as £28,781 million and £31,654 million for the year 2015. The consolidated income statement in the annual report does not provide a breakdown of operating expenses. It simply gives the operating costs (as loss) for the year 2016 as £1,784 million and £1,720 million for the year 2015. For the purposes of this review, that is in order to calculate the operating ratio (operational efficiency) for SSE operations, the operating costs are considered to be (rightly or wrongly) the operation and maintenance costs. The remaining necessary information is extracted from the individual statements in the annual report. Fuel (and consumables) for the year 2016 are listed as £216 million for 2016 and £338 million for the year 2015. Staff/personnel costs are listed as a total of £916 million in 2016 and £875 million in 2015, and according to SSE (2016), depreciation and amortisation are items included in operating costs (loss). Adding these values gives the total operating costs as £2,916 million in 2016 and £2,933 million for the year 2015. The operating ratio (that is, operational efficiency) therefore for the year 2016 is 10% and 9% for the year 2015, which is remarkably good, but improbable, especially in the recent economic climate. However, the SSE combined income statement also gives the cost of sales (as loss) as £25,859 million for 2016 and £31,654 million for the year 2015. If these values are considered or used as the total operational costs for the company business and used to calculate the operational efficiency of SSE then the operating ratio for the year 2016 is 92% and 92% for 2015 indicating that the operational efficiency in SSE is consistent (SSE, 2016).

Following are the operating ratios for two major power generating companies in Asia. Datang Power (China) and NTPC Ltd (India).

2.1.11 China Datang Corporation

China Datang Corporation (CDC) is a power generation group established in December 2002, following the partitioning of the power generation assets of the former State Power Corporation of China. It is a solely state-owned corporation directly managed by the Central Politburo of the Communist Party of China (CPC) and is the experimental state-authorised investment and state share-holding enterprise. CDC specialises in management of state-owned assets invested by the state and owned by CDC; development, investment, construction, operation and management of power energy; organisation of power (thermal) production and sales; electric power equipment manufacture, maintenance and commissioning; power technology development and consultation; contracting and consulting of electric power engineering and environmental protection projects, renewable energy development, conducting and acting as agent for import and export of commodities and technologies of various types, contracting of overseas projects and domestic projects internationally; exporting equipment and materials and providing labour abroad required to carry out overseas projects. China Datang Corporation (CDC) is the parent company to a number of subsidiaries including Datang International Power Generation Ltd (Datang Power). Datang Power has its headquarters in Xicheng District, Beijing. The principal activities of the Company and its subsidiaries (Group) are power generation and power plant development in China with a focus on coal-fired power generation. Among other activities, the Group also engages in coal trading and chemical products manufacturing. Datang Power is a Chinese independent power generation company with a total installed capacity of >42 GW. At the end of 2015, coal, hydro, wind and photovoltaic power generation accounted for 80.71%, 14.41%, 4.43% and 0.45% of the Company's installed power generation capacity, respectively. During 2015, 19 power generation projects were officially approved amounting to a total capacity of 9.5 GW. CDC holds a share of approximately 35% in Datang Power (China Datang Corporation, 2016).

The consolidated financial statements of income for Datang Power give the total operating revenues for 2015 as RBM'000 61,890,285 and RMB'000 70,194,327 for the year 2014. The operating expenses including fuel, repairs and maintenance, staff/personnel cost and, depreciation and amortisation for the years 2015 and 2014 are given as RMB'000 38,333,973 and RMB'000 44,471,019, in total, respectively. The operating ratio therefore for Datang Power operations for the year 2015 was 62% and about 63% for the year 2014, indicating that although operating revenue for the year 2015 was approximately 12% lower compared to 2014, the operational efficiency of Datang Power operations dropped only by a margin of 1% in 2015 compared to 2014 (Datang International Power Generation Co Ltd, 2016).

2.1.12 NTPC

The principal business of NTPC Ltd is power generation and sale of bulk power to state power utilities. Other business includes providing consultancy, project management and supervision, oil and gas exploration and coal mining. NTPC is headquartered in New Delhi (India). The company owned and operated a total capacity of >38 GW at the end of March 2015 of which ~33.5 GW was coal-based. The company also generated >6 GW of capacity through joint ventures and subsidiaries, of which ~4.2 GW was coal-based. In the financial year 2014/15, total domestic coal supply to NTPC was 151 Mt and imports totalled 16.4 Mt. According to NTPC (2015), India had its highest growth in coal production in 23 years at 8.3% in 2014/15 and that, as such, makes coal the mainstay of the power sector in India. The fuel mix of installed power generating capacity as on 31 March 2015 is shown in Figure 7.

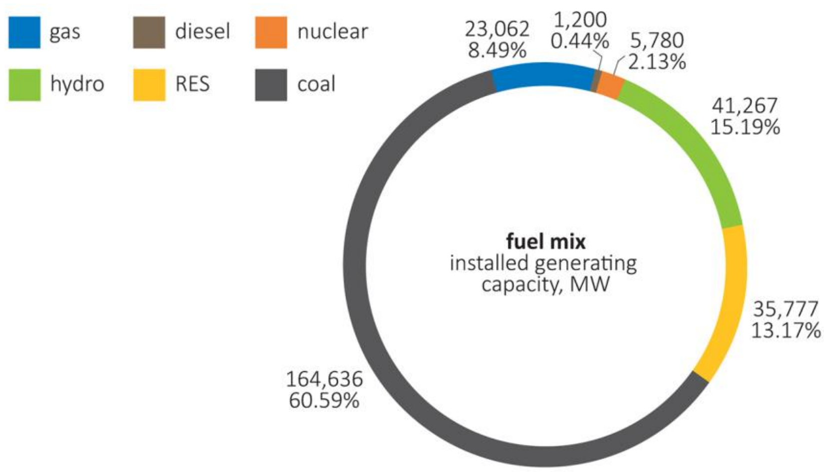


Figure 7 The fuel mix of installed power generating capacity in India, MW (NTPC, 2015)

The NTPC statement of profit and loss for the year ended 31 March 2015 gives the gross revenue from operation for 2014/15 as ₹ Crore 73,915.69 and for the year ended 31 March 2014 it gives ₹ Crore 72,644.02. A Crore is a unit in the Indian numbering system equal to ten million (10,000,000 or 10^7). It is widely used in India, Bangladesh, Pakistan and Nepal, and is written in these regions as 1,00,00,000 with the local style of digit group separators. The operating expenses including fuel, staff/personnel cost, depreciation and amortisation and generation, administration and other expenses for the years 2014/2015 and 2013/14 are given as ₹ Crore 62,405.93 and ₹ Crore 58,340.53 for 2013/2014 in total. The operating ratio therefore for NTPC operations for the year 2014/15 was 84% and about 80%

for the year 2013/14, indicating that the operational efficiency of NTPC operations decreased by a margin of 4% in 2014/15 compared to 2013/14 (NTPC, 2015).

Summary

In brief, in my opinion, an operating ratio of 75%–85% or thereabouts may be considered desirable as it indicates a company's ability to generate funds from the company operations and therefore produce revenue for future development and increased capacity. Within operational costs, there are many factors that impact the operational efficiency of a power generating company. These include cost of fuel, staff/personnel, O&M and depreciation and amortisation (the higher these factors are the higher the operating ratio is and the lower the operational efficiency). Within a power plant, operations are impacted by many factors including, for example, plant load factor, which is the ratio of the total kWh actually generated and sold, to the total kWh which the plant can generate if and when operating at full load. Another indicator is the overall availability factor, considered by some as a better index for comparing plant performance. These, as well as other factors, are discussed in Sections 3.1 and 3.1.1. All in all, in order to achieve the desired operating ratios (that is, operational efficiency) within a plant or a power generating company, management as well as operational efforts are necessary to identify and resolve the problems in the various loss areas by taking the appropriate actions to maximise the power generation and minimise the loss. TIFAC (2009) discussed in detail techniques to improve operational efficiency of thermal power stations in India.

As stated above, the information given in this chapter on company operating ratios is based on annual reports, which vary in their presentation of revenue and operating expenses and, as such, ***comparison must not be made between different companies' operating ratios.*** However, a company management team may and should analyse operating ratios for a number of reasons, for example, to assess the operational efficiency and performance of the company over time, to allow a comparative study of operational efficiency, and to highlight the position of the company with regard to revenue and operational expenses, which impact profitability and future investment. In simple terms, operating ratios data allow a company to compare its operational performance over different times, analyse the said data and take the necessary steps in order to maintain as good an operational performance as possible and as such, as low an operating ratio (%) as possible.

3 Basic economics of power generation

Determining the cost per unit (1 kWh) of production of electrical energy is known as the economics of power generation. Demand for electricity at a moderate rate is a driving force for the development and construction of power generating facilities that produce electricity at an acceptable rate to consumers. Terms often used in the subject of economics include *interest and depreciation*. Constructing a power station involves investing a large amount of capital in the project. This is generally borrowed from banks or other financial institutions and the plant owner has to pay an annual *interest* on the borrowed amount. As such, when calculating the cost of production of electricity in a facility, the interest payable on the capital investment must be included. The rate of interest depends on market conditions among other factors, and may vary from 4–8% per annum (Mehta and Mehta, 2005).

Depreciation refers to the decrease in the value of the power plant equipment and building due to continuous operation. If the power station equipment were permanent, then interest on the capital investment would be the only cost to be incurred. However, although every power station has a useful life ranging from fifty to sixty years, from the time the power station is constructed, its equipment steadily deteriorates due to wear and tear resulting in a gradual reduction in the value of the plant. This reduction in the value of the facility year on year is known as the annual depreciation. Due to depreciation, a plant has to be replaced by a new one after its useful life ends. Therefore, theoretically, suitable amounts of income must be set aside annually (the so called depreciation charge) in order that by the time the plant retires, the collected amount, by way of depreciation, equals the cost of a replacement facility. It is thus important that while determining the cost of production, annual depreciation charges be included. According to Mehta and Mehta (2005), three of the commonly used methods for determining the annual depreciation charge are the straight line method, the diminishing value method and the sinking fund method.

In the straight line method, a constant depreciation charge is made every year on the basis of total depreciation and the useful life of the property; that is, the annual depreciation charge would be equal to the total depreciation divided by the useful life of the plant. For example, if the initial cost of equipment is US$1,000,000 and its value is US$100,000 at its end of life of 40 years then the (Mehta and Mehta, 2005):

$$\text{Annual depreciation charge} = \frac{Total\ depreciation}{useful\ life} = \frac{1{,}000{,}000 - 100{,}000}{40} = US\$\ 22{,}500$$

The annual depreciation charge on the straight line method may also be expressed as:

$$\text{Annual depreciation charge} = \frac{P - S}{n}$$

Where: P = initial cost of equipment, S = salvage value at end of life, and n = useful life in years (*see* Figure 8).

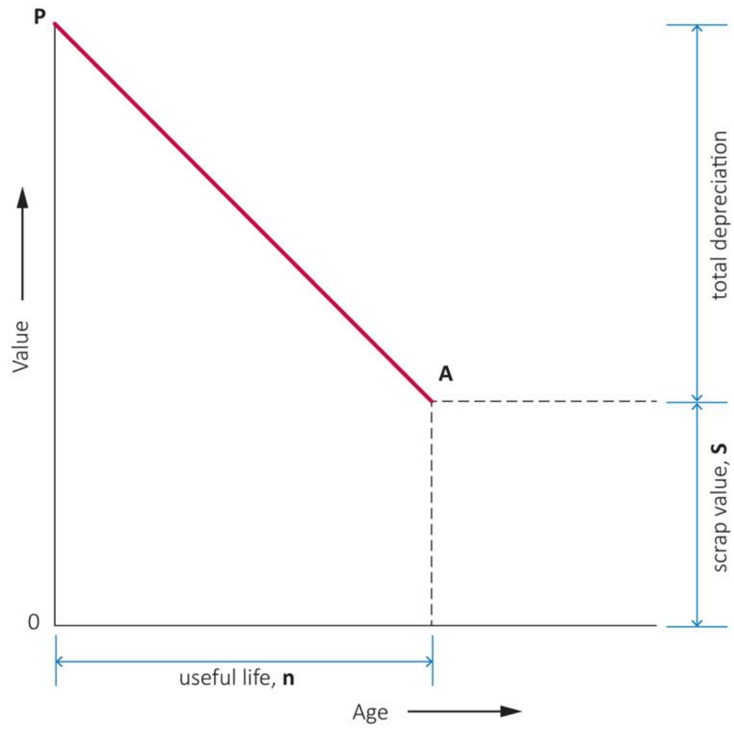


Figure 8 The straight line method to determine annual depreciation charges (Mehta and Mehta, 2005)

The straight line method is simple and easy to apply as the annual depreciation charge can be readily calculated from the total depreciation and useful life of the equipment. However, this method has two major shortcomings which are: the assumption of a constant depreciation charge year on year which may not be accurate and also the method does not account for the interest charge, which may be drawn during accumulation.

In **the diminishing value method**, the depreciation charge is made every year at a fixed rate on the diminished value of the equipment. In other words, the depreciation charge is first applied to the initial cost of equipment and then to its diminishing value year on year. For example, supposing the initial cost of the equipment is US$100,000 and its salvage/scrap value after the useful life is zero. If the annual fixed rate of depreciation is 10%, then depreciation charge for the first year would be 0·1 x 100,000 = US$10,000. The value of the equipment is diminished by US$10,000 and becomes US$90,000. For the second year, the depreciation charge in then made on the diminished value (that is, US$90,000) and becomes 0·1 x 90,000 = US$9000 and similarly for the following year and so on and so forth. So, if P = capital cost of equipment, n = useful life of equipment and S = salvage/scrap value at end of life; and supposing the annual depreciation is 10% or 0.1 is x, the purpose is to obtain the value of x in terms of P, n and S, as follows:

$$\text{Value of equipment after one year} = P - Px = P\ (1-x)$$

$$\text{Value of equipment after 2 years} = [P - Px]\ - [(P - Px)\text{x}] = P - Px - Px + Px^2 = P(x^2 - 2x + 1)$$

$$= P\ (1-x)^2$$

$$\text{So, value of equipment after n years} = P\ (1-x)^n$$

As the value of equipment after n years is S (salvage/scrap value) it follows that:

$$S = P\,(1-x)^n \; or \; (1-x)^n = \frac{S}{P} \; or \; 1-x = \left(\frac{S}{P}\right)^{\frac{1}{n}} \; or \; x = 1 - \left(\frac{S}{P}\right)^{\frac{1}{n}}$$

Depreciation for the first year is Px or xP or as per the last equation $P\,[1-\left(\frac{S}{P}\right)^{\frac{1}{n}}]$ and so similarly, the annual depreciation charge for the subsequent years can be calculated. Figure 9 shows a graphical representation of the annual depreciation diminishing value method.

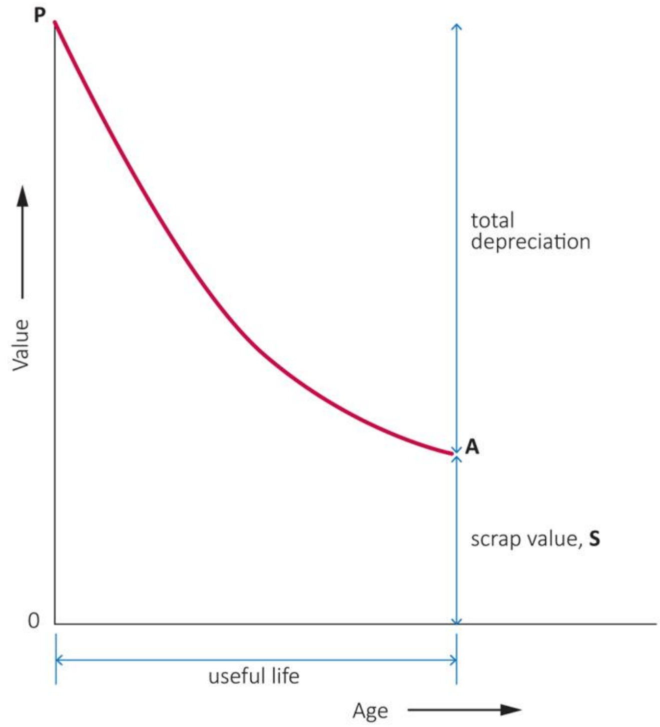


Figure 9 Graphical representation of the annual depreciation diminishing value method (Mehta and Mehta, 2005)

Figure 9 shows that depreciation charges are high in the early years but decrease gradually in the latter years. This method also has two main drawbacks. Firstly, low depreciation charges are made in the late years while the maintenance and repair charges increase due to ageing equipment. Secondly, the depreciation charge is independent of the rate of interest which, it may draw during accumulation. Such interest, if earned, may be treated as income.

In **the Sinking fund method,** a fixed depreciation charge is made every year and interest compounded on it annually. The constant depreciation charge is such that the total of the annual instalments plus the interest accumulated equal the cost of replacement of equipment at end of life. Although this method is not applied/used frequently in the power generating industry, in practical depreciation accounting, it is the fundamental method in economic studies (Mehta and Mehta, 2005).

The economics of conventional thermal generation projects differ substantially from those of intermittent, low marginal cost renewables such as solar and wind. The largest differentiator between conventional coal and gas projects tends to be the cost of input fuels, which are highly localised (WEC, 2013).

3.1 Costing of electric power

Electric power is provided to end users by power plants that are often located in remote areas, far from the point of consumption. The economics of such facilities are largely dependent on cost. As with other production technologies, power generation entails fixed and variable costs. The fixed costs of power generation are essentially capital and land costs. The capital cost of building a power plant varies from region to region, largely as a function of labour and regulatory costs, which include obtaining siting permits, environmental risk assessments and approvals, and so on. It is important to realise that constructing a power plant is a costly and lengthy process in which costs of mitigating environmental impacts play a major role in the decision making. Table 3 shows capital cost ranges for several power generating technologies. According to Blumsack (2014), although the ranges in Table 3 are wide, they have a large margin of uncertainty in the final cost of constructing a power plant.

Table 3 Typical capital and operating costs for power plants. Note that these costs do not include subsidies, incentives, or costs such as water or air emissions controls (Blumsack, 2014)

Technology	Capital cost, US$/kW	Operating cost, US$/kWh
Pulverised-coal combustion	500–1000	0.02–0.04
Natural gas combustion	400–800	0.04–0.10
Coal gasification combined cycle (IGCC)	1000–15000	0.04–0.08
Natural gas combined cycle (NGCC)	600–1200	0.04–0.10
Wind turbine (includes offshore wind)	1200–5000	<0.01
Nuclear	1200–5000	0.02–0.05
Photovoltaic solar	≥4500	<0.01
Hydroelectric	1200–5000	<0.01

Operating costs for a power plant include fuel, labour and maintenance costs. Unlike the fixed capital costs, total operating costs depend on how much electricity the plant generates and sells. The operating cost required to produce each MWh of electric energy is referred to as the marginal cost. Fuel costs dominate the total cost of operation for fossil-fired power plants. For example, a 100 MW power station operating at 50% load factor may burn about 20,000 t of coal per month and produce ash to the tune of 10–15% of the fired coal, that is 2,000–3,000 t of ash. In fact, in a thermal station, about 50–60% of the total operating cost consists of coal purchasing and handling. For renewables, fuel is generally free (with the exception of biomass power plants and depending on the source) and the fuel costs for nuclear power plants are a minor proportion of total generating costs. For coal-fired power plants, the fuel, labour and maintenance costs dominate the total operating costs. In general, power generating facilities face a trade-off between capital and operating costs. Plants that have higher capital costs tend to have lower operating costs. Furthermore, fossil-fuel fired plants tend to have operating costs that are extremely sensitive to changes in the underlying fuel price. The typical ranges for operating costs for various types of power plants are also shown in Table 3. The apparent trade-off between capital and operating costs of the different technologies, makes comparing the overall costs of different power plants somewhat difficult. In general, power plants costs are compared using a measure called the levelised cost of energy (LCOE). According to the EIA (2015), LCOE is often cited as a convenient summary measure of the overall competiveness of different generating technologies. It represents the per-kilowatt hour (kW) cost (in real US$) of building and operating a generating plant over an assumed financial life and duty cycle. Key inputs to calculating LCOE include capital costs, fuel costs, fixed and variable operations and maintenance (O&M) costs, financing costs, and an assumed utilisation rate for each plant type. The importance of the factors varies among the technologies. LCOE changes in rough proportion to the estimated capital cost of generation capacity. For technologies with significant fuel cost, both fuel cost and overnight cost estimates affect LCOE significantly. *Overnight cost*, a terminology used frequently to describe power plants, is the cost of constructing a project if no interest was incurred during construction, as if the project was completed "overnight". The unit of measure typically used when citing the overnight cost of a power plant is $/kW. The availability of incentives such as tax credits, can also impact the calculation of LCOE. As with any projection, there is uncertainty about all of these factors and their values can vary regionally and across time as technologies evolve and fuel prices change.

According to Blumsack (2014), irrespective of technology, all generators share characteristics which influence a plant's operations including:

- ramp rate: a variable that influences how quickly the plant can increase or decrease power output, in MW/h or in % of capacity per unit of time;
- ramp time: the amount of time (hours) it takes from the moment a generator is turned on, to the moment it can start providing energy to the grid at its lower operating limit (*see* below);
- capacity: the maximum output of a plant, in MW;
- lower operating limit: the minimum amount of power a plant can generate once it is started, in MW
- minimum run time: the shortest amount of time (hour) a plant can operate once it is started;
- no load cost: is the cost of starting the plant, but keeping it 'spinning,' ready to increase power output, in US$/MWh. Another interpretation of the no load cost is that it is the fixed cost of operation; that is, the cost incurred by the generator that is independent of the amount of generated energy;
- start-up and shut-down costs: are the costs involved in starting the plant and shutting down operations, in US$/MWh.

The minimum run time and ramp times determine the flexibility of the generation source; they vary greatly in different plants and are a function of regulations, type of fuel, and technology. In general, less flexible plants that require longer minimum run times and have slower ramp times serve as baseload energy, while more flexible plants that require shorter minimum run times and have quicker ramp times are better suited to satisfying peak demand. Table 4 and Figure 10 show approximate (order of magnitude) minimum run times and ramp times for several generation technologies. It is important to note that, in some sense, these are 'soft' constraints, that is changeable constraints as it is possible, for example, to improve a coal-fired power plant flexibility although, unless closely monitored and checked, this may impose a large cost in the form of wear and tear on the plant components. Typical ramp and run times for power plants are shown in Table 4. A relative comparison of operating cost and operational flexibility for different power plant technologies (excluding most renewables as their operational flexibility is partially dependent on prevailing weather conditions such as irradiance and wind speed/direction) is shown in Figure 10.

Table 4 Typical ramp and run times for power plants (Blumsack, 2014)

Technology	Ramp time	Minimum run-time
Simple cycle combustion turbine	Minutes to hours	Minutes
Combined cycle combustion turbine	Hours	Hours to days
Nuclear	Days	Weeks to months
Wind turbine (includes off-shore wind)	Minutes	None
Hydroelectric (includes pumped storage)	Minutes	None

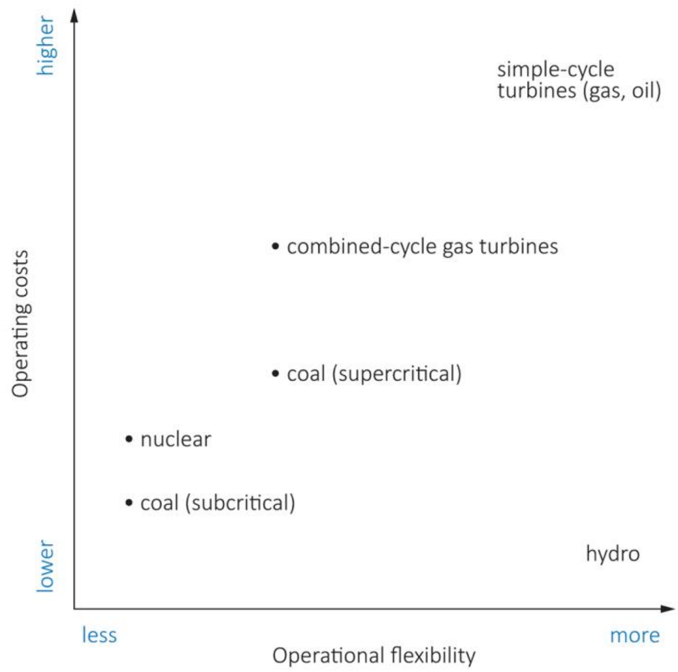


Figure 10 Relative comparison of operating cost and operational flexibility for different power plant technologies (Blumsack, 2014)

According to Schröder and others (2013), start-up time represents the time required for a plant to start-up and in particular to synchronise the generator to the grid frequency and thus deliver load in the following time periods. Main impacts and restrictions for start-up times are thermal stress through extreme temperatures and pressure differences within the thick-walled components of a furnace. This is especially the case for baseload power plants with attached steam cycles. In addition, the start-up time is (among other factors) a function of the state (that is, warmth) of a unit, which may include cold, warm and hot start-ups: a cold start is when a power plant has been shut down for more than 50 hours, a warm start is when a power plant has been turned off for >8 hours and <50 hours and a hot start is when a power plant has been switched off within 8 hours of the next start-up. Hot starts are a characteristic of power plants running in a daily cycling mode which are shut down over night and start generation in the morning. Start-up costs are determined by three main factors (Schröder and others (2013):

- Costs of start-up fuels, auxiliary electricity requirements, chemicals and additional manpower necessary for unit start-up. In general, the use of fuel and manpower is higher while synchronising turbine and generator, and during the subsequent process of adjusting and controlling steam pressure and temperature.
- Depreciation of the components exposed to wear along with higher maintenance, overhaul capital expenditures, unit life shortening, and increased forced outage rates.
- Lost profits due to lower part load efficiency of power plants when ramping.

Henderson (2014) reviewed increasing the flexibility of coal-fired power plants by discussing the technical features that are available to enable plants to operate under rapid output changes with minimum detriment to their integrity, efficiency and emissions. Areas with the greatest potential for adverse effects due to cycling are the boiler and steam turbine systems. When the plant is called upon to operate frequently at rapidly variable output and with frequent shut-downs and start-ups, resultant changes in temperature and pressure give rise to increased stresses on their various components. The consequences are reduced life, reduced performance and increased costs. Mills (2011) noted the growing capacity of renewable energy plants around the world and the effects of their intermittent and highly variable output on the operation of coal-fired plants. In the absence of sufficient large-scale electricity storage capability, coal (and gas) fired units in some countries, such as Germany, are required to deliver greatly varying output to enable the grid system to meet demand at all times. Henderson (2014) found that flexible operation adds thermal and mechanical fatigue stresses to the creep damage that occurs anyway with time in the pressure parts of a pulverised-coal-fired power plant. Creep and fatigue are terms commonly used in engineering mechanics. Creep is time-dependent change in the size or shape of a material due to constant stress (or force) on that material (Kumar and others, 2016). In fossil-fuelled power plants, creep is caused by continuous stress that results from constant high temperature and pressure in a pipe or a tube occurring during steady state baseload operation. Fatigue is a phenomenon leading to fracture (failure) when a material is under repeated, fluctuating stresses. In a fossil-fuelled power plant, such fluctuating stresses result from large transients in both pressures and temperatures. These transients typically occur during cyclic operation. The term creep fatigue interaction suggests that the two phenomena (creep and fatigue) are not necessarily independent, but act in a synergistic manner to cause premature failure. Materials behave in a complex manner when both types of stresses occur. Kumar and others (2016) consider creep-fatigue interaction one of the most important phenomena contributing to component failures and can have a detrimental effect on the performance of metal parts or components operating at elevated temperatures. The authors found that creep strains (that is, mechanical deformation as a result of stress) can reduce fatigue life and that fatigue strains can reduce creep life. These, together with corrosion, differential expansion, and other effects, often synergistically, result in a reduction of the expected life of such components, which are designed for baseload operation. Operators and manufacturers have considered the mechanisms of these detrimental effects, and have developed some solutions. Koripelli (2015) discussed the most common and problematic effects of cycling on boiler metals. Means of increasing flexibility that were constrained by non-life limiting considerations, such as better firing systems and better auxiliary motor drive systems, have been devised. *The result is the availability of new and modified equipment, revised operating procedures, new specifications and further new ideas for making future plant designs more flexible while keeping efficiency as high as possible* (Henderson, 2014; Kumar and others, 2016).

Henderson (2014) considered that there are many features in specific pulverised-coal power plant areas that can be incorporated to give better flexibility, including:

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

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

Ensuring emissions control systems remain effective – installing means to maintain selective catalytic reduction (SCR) NOx control system exit temperature within specification at part load to avoid catalyst blocking and damage to the air heater; minimising shut-downs and start-ups of flue gas desulphurisation (FGD) systems, and modernising control systems to reduce energy demand; for dust separation devices, ensuring adequate temperatures to avoid moisture condensation on particles.

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

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

Auxiliary plant – using flexible drives.

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

In conclusion, Henderson (2014) considered that potential damage mechanisms from plant cycling duty are well known and the technical means exist for conventional combustion-based plants to achieve the necessary flexibility without unacceptable loss of plant life and thermal efficiency. Work is in progress on means to increase the flexibility of future systems. It is important that financial rewards are sufficient to cover the cost of maintaining grid balancing plants so that suitable fossil-fired capacity continues to be available to keep power supplies reliable.

In an in-depth study of energy efficient design of auxiliary systems in fossil-fuelled power plants, ABB (2009) discussed life-cycle costing (LCC), which is a method of calculating the cost of a system over its lifetime. LCC is calculated in the same way as 'total cost of ownership' (TCO). A technical accounting of systems costs including initial costs, installation and commissioning costs, energy, operation, maintenance and repair costs as well as down time, environmental, decommissioning and disposal costs. These technical component costs include (ABB, 2009):

$$LCC = C_A + C_E + C_I + \sum_{0}^{n} (CP_M + CC_M + CO_P + CO_0 + CR) + C_D$$

Where CA = cost of apparatus, CE = cost of erection, CI = cost of infrastructure, CPM = cost of planned maintenance, CCM = cost of corrective maintenance, COP = cost of operation (load and no-load losses), CR = cost of refurbishment or replacement, CD = cost of disposal, n = years of operational lifetime.

Additional, non-technical costs that should be accounted for in budgetary estimates include insurance premiums, taxes, and depreciation. According to ABB (2009), all costs in LCC calculations should be discounted to present value (PV). For systems that emit CO_2 or other pollutants, the cost of operation should include remediation costs, and the taxes which authorities charge (or may charge) per unit of emissions. For electrical loads powered with fossil-fuels, the CO_2 amounts (t) are relevant, but the carbon (CO_2) tax should not be added to that component's operational costs if the tax has already been factored into the price of the consumed electricity. ABB (2009) consider that LCC analyses often count only single benefits, such as the electricity directly saved by a greater efficiency of a new component when there are numerous other benefits such as reduced electricity consumption on the size and wear of upstream, power system components. Other benefits that are difficult to quantify in LCC analysis include reduced maintenance via the elimination of the control valve, for example. In a detailed LCC calculation it is important to consider component substitution costs.

3.1.1 Parameters that influence costing

Traditional coal-fired power plants were designed to operate at baseload. Modern facilities are designed to be more flexible. However, modifying any plant operation to adjust energy output is plant specific. New build facilities with flexible design are built to cycle from initial start-up, making capital cost recovery relatively slow. As these plants are more advanced, they are inherently more expensive. In general, all coal-fired power generating units have additional costs due to flexible operation not only in fuel costs but also in additional wear and tear.

Intermittent high demand for electricity can be met by plants operating at peak load. The peaking load occurs, on average, less than ~15% of the time. When the power is needed continuously, demand is met by facilities operating at baseload. Baseload is that load below which the demand never falls, that is, the baseload must be supplied 100% of the time. The intermediate load transpires between 15–100% of the time. At any given time, there is also always a reserve margin, which is a specified amount of backup electricity generating capacity that is available to compensate for potential forecasting errors or unexpected power plant outages or shut-downs. Electricity demand, supply, reserve margins, and the mix of electricity generating technologies is constantly monitored and managed by grid operators to ensure continuous, uninterrupted electricity supply to end users. In some situations, and in order to improve industrial plant cost effectiveness, some companies are implementing cogeneration, which is the production of electricity in-house along with industrial process steam (for example, Valmet, Finland).

As stated above, the transformation of the power sector to greater utilisation of renewable energy, demand response, and other emerging technologies requires flexibility in existing coal, and other fuel, power generation fleet. In other words, units must be able to cycle up and down to meet the demand for electricity. As such, flexibility will be instrumental in valuing coal in an increasingly low-carbon energy system. A coal-fired power plant built for baseload generation may be modified (depending on its design features, such as cycling) to meet peak demands, cycling on and off up to four times a day to meet fluctuating electricity demand. Key to the success is changing operational practices: monitoring and managing temperature ramp rates; creating a suite of inspection programmes for all affected equipment, large and small; and continual training of the workforce to reinforce the skills needed in monitoring and inspections. Modifications and procedural changes will also be required to improve equipment reliability.

The characteristics necessary for a productive energy generating system are shown in Figure 11. **Reliability** is the characteristic of a plant expressed as a probability that it will operate under specified conditions for a specified period of time. **Maintainability** is the characteristic of design and installation expressed as the probability that a plant will be retained in or restored to a specified condition within a specified period of time when maintenance is performed in accordance with prescribed procedures and resources. **Availability** is the characteristic of a plant expressed as a probability that it will be operational at a randomly selected future point in time (Curley, 2013). The commercially sensitive nature of plant availability data makes it difficult to obtain such information, and individual plant/unit statistics are not published in the public domain, in general.

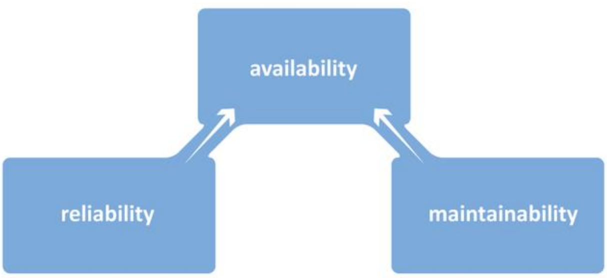


Figure 11 The characteristics necessary for a productive energy generating system (Curley, 2013)

Profitable long-term operation of a power plant involves providing maximum availability by optimising equipment life. This can be achieved by developing and implementing effective maintenance, environmental, and safety management programmes. Preventative, predictive and scheduled maintenance procedures would result in achieving maximum plant availability, equipment reliability and minimise forced outages. Such procedures would pre-empt major refurbishment that may be, and often are, necessary at a plant. Generation cost parameters include:

- Start-up (non-fuel) (US$/MW) is the starting of a unit that is offline. Starts are described as hot, warm, or cold, depending on the temperatures of the metal in the turbine. Two shifting is an operational sequence whereby a generating unit is started and shut down within a 24-hour period. Typically, the shut-down is overnight. Also used as a general term describing more than one shut-down within a 24-hour period (2-shifting or 4-shifting). Start-up processes impact costs as the fuel consumption and manpower requirements are higher than when the plant operates at generation or rated capacity. Generation or rated capacity is the maximum output a generator can produce under specific conditions. Furthermore, operating a plant below rated capacity influences the efficiency of the entire generation process. This effect is captured in the part load efficiency, which itself is a determinant of generation costs. It is important to note that the conditions and impact on plant performance and costs are generally site specific.
- Cycling, which is a range of operations in which a plant's output changes, including starting up and shutting down, ramping up and down, and operating at part-load (less than full output). Ramping results in output that varies between full and minimum levels in order to follow changes in generation demand.
- Ramping penalty. Significant ramping (down and up) of baseload resources (such as coal-fired plants) results in increases in their maintenance cost and decreased time between maintenance work. The ramping rate, Up\Down defines the unit capability to move within the hour; ramping penalty, however, controls the unit ability to respond to changes. A question arises: whether the penalty in terms of currency (that is, US$ or Euros for example) is reported as part of O&M costs or not. Either way, a ramping penalty can impact the operating price.
- Forced Outage is an unplanned component failure (immediate, delayed, postponed, start-up failure) or other condition that requires the unit be removed from service immediately or within a specific time period. Equivalent forced outage rate (EFOR) is the hours of unit failure (unplanned outage hours and equivalent unplanned de-rated hours) given as a percentage of the total hours of the availability of the unit (unplanned outage, unplanned de-rated and unplanned service hours). In other words, EFOR is a measure of the probability that a generating unit will not be available due to forced outages or forced deratings (IEEE, 2006). The lower the EFOR, the better the performance of the unit. EFOR is also considered a measure of a plant's unreliability.
- Variable operation and maintenance (VOM) including wear and tear: Wear means the component reaches the end of its natural life through ordinary causes (for example, corrosion, thermal fatigue), though wear can be accelerated by cycling. Tear refers to an abnormal event that accelerates the end

of life, such as what occurs during poor control of operating conditions. Tear can occur during baseload operations, but abnormal events are generally more likely during some cycling modes.

A breakdown of cycling-related costs by Schröder and others (2013) indicated that 52–57% of capital and maintenance cost was due to the boiler, 22–27% was due to the turbine, 9–15% was due to balance of plant, 2–3% was due to plant control and 5–8% was due to fuel handling. Analysis of the literature reviewed by Schröder and others (2013) showed that for hard coal, lignite and combined cycle gas turbine (CCGT), costs of a hot start-up amounted to approximately one third of the additional costs for a cold start. For example, one full start-up may require additional fuel use with costs in the order of €30,000 (hot) and €100,000 (cold) for coal-fired power plants of 1000 MW capacity. The cost for starting a nuclear power plant is higher at €200,000 per start. It should be noted that differences between hot, warm, and cold start-up costs exist for all systems except for nuclear power. Schröder and others (2013) concluded that the costs in the reviewed literature demonstrate a high flexibility in modern power plants and showed that specific start-up cost differences were rather modest across the generating technologies.

Ramping load gradients describe the ability to adjust power generation within a certain timeframe (for example, minutes). The main purpose for ramping gradients is to reduce plant component thermal stress by avoiding rather extreme changes in temperatures and pressures. It is important to note that the ramping gradient of a power plant depends on the investigated timeframe and plant operation. In the short term, power plants based on steam cycles are able to provide additional energy very quickly by releasing thermal energy stored in the generation process. Following that, an increase in fuel flow is necessary to maintain the additional energy output. Schröder and others (2013) maintain that the ability to provide quick output increases requires the power plant to operate below optimal conditions to store the required thermal energy. Generation technologies characterised by modest thermal storage capacity (for example, NGCC) increase their output by directly increasing the fuel intake. In addition to the increased fuel cost, ramping costs reflect the additional capital and maintenance costs of changing the energy output of a plant. In general, ramping costs are relatively low compared to start-up costs. However, they can be relevant for generation technologies, such as coal-fired power plants designed for baseload applications (Kumar and others (2012).

Schröder and others (2013) also discuss minimum load levels and minimum up- and down-times, which are helpful tools in modelling a power plant's unit commitment and dispatch. Minimum load levels refer to the lower generation limit at which a plant can be effectively operated. Below the minimum load level, a stable operation may not be achievable due to factors including insufficient temperatures or excessive emissions. As such, thermal power plants can operate in the capacity range from minimum load to rated capacity. It is important to note that the minimum load depends on the design of the generation process. For example, for lignite power plants with an optimised plant design, a reduction of the minimal load to 35% or even 17.5% (using a two-boiler concept) may be expected. In addition, minimum up- and down-times (or online/offline times) are used to characterise the limitations on flexibility of thermal power plants. Schröder and others (2013) consider that up- and down-times are in principle not 'hard' physical limits but they can be considered as economic limits since operators are interested in keeping the number of start-ups and shut-downs to a minimum in order to avoid, for example, excessive thermal stress on power plant equipment.

The challenges and opportunities in the electric power system flexibility was the subject of a document by the Electric Power Research Institute (EPRI, USA). According to EPRI (2016), coal-fired power plants, depending on plant type and design can adjust output within a fixed range in response to plant or market conditions. This need for flexibility is changing a plant's operational mode to either more frequent shut-downs when market or grid conditions warrant, more aggressive ramp rates (rate of output change), or lower desired minimum sustainable load, which provides a wider operating range. Flexibility necessitates the transition of a plant to one or more of the following duty cycles (EPRI, 2016):

- Two-shifting in which the plant is started up and shut down once a day.
- Double two-shifting in which the plant is started up and shut down twice a day.
- Weekend shut down in which the plant shuts down on weekends. This is often combined with load following and two-shifting.
- Sporadic operation in which the plant operates for periods of less than two weeks followed by shut down for more than several days.
- Load-following in which the plant operates for more than 48 hours at a time, but varies output as demand changes.
- On-load cycling in which, for example, the plant operates at baseload during the day and then ramps down to minimum stable generation overnight.

According to EPRI (2016), operating in these modes can cause damage and incur costs, as such cycling duty can accelerate thermal fatigue, thermal expansion, fireside corrosion, and rotor bore cracking. Cycling units not designed for such operating modes can lead to more component failures, unplanned outages, increased heat rate, decreased revenue, and staff scheduling and training challenges. At the same time, constraints on cycling operation can be imposed by new or upgraded emission controls such as selective catalytic reduction (SCR), flue gas desulphurisation (FGD), and mercury controls. The key steps to improving flexible operations are shown in Figure 12 (EPRI, 2016).

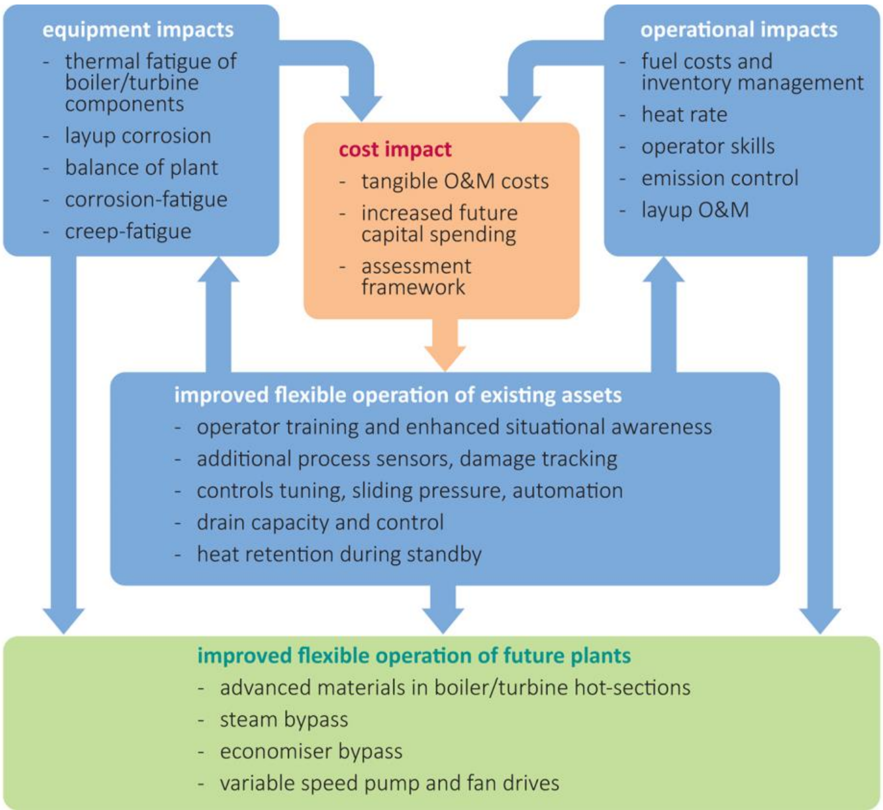


Figure 12 Impacts of cycling and key steps for improving flexible operations in coal-fired plants (EPRI, 2016)

EPRI's efforts to research, study and address the issues resulting from plant cycling include (EPRI, 2016):

- conduct operational case studies to identify strategies to reduce start-up time and minimum sustainable loads;
- improve the understanding of damage mechanisms due to increased cyclic service;
- improve methods for protecting water-side corrosion;
- minimise emissions during cycling operations;
- develop boiler and heat recovery steam generator specifications for flexible operations;
- develop methods for reducing unit minimum loads;
- develop advanced monitoring during transients;
- develop new plant designs;
- assess combustion-related impacts of low load and load following operation, with a goal to develop guidelines and best practices for minimising impacts on boiler tubes; and
- address cycling impacts on heat rate, which deteriorates significantly at lower and transient loads.

EPRI (2016) examines the challenges and opportunities that are driving changes to the power system and the system's research and development needs including coal, natural gas, nuclear, poly generation, hydro, renewables and electric energy storage. The examination includes power generation, the power delivery system, power system operations and planning, and consumers, while addressing environmental impacts.

The increasing utilisation of intermittent energy sources means that, traditional power plants have to operate in shorter cycles of start-ups and shut-downs, necessitating taking measures to increase flexibility and, decrease impacts on costs. Following are some of the measures and new approaches and technologies summarised by Schröder and others (2013) to increase power plant flexibility:

- Delaying the cooling down of boilers: in order to conserve warm- and hot-start-up conditions as long as possible, auxiliary steam may be used to heat the main steam generator during standstill. As major heat losses occur through the chimney, a stack damper may further help limit heat loss during shut down. Cooling down of the boiler can also be delayed by the use of gland water (pressurised water), which reduces steam leakage and air ingress/seepage by sealing steam in the turbine. Steam leakage would require additional start-up procedures. Measures can be taken that delay the cooling down of the boiler and thus increase the maximum possible standstill periods during which criteria for hot and warm start-ups still apply.

- Air cooling in gas turbines: in advanced power plant types, such as the CCGT plant, using air rather than steam cooling for internal gas turbine components is reported to bring additional improvements to start-up times, with lower complexity in engine and plant leading to more flexible operation. However, air cooling lowers the overall efficiency rate since the cooling air is sourced from the gas turbine.

- Control technology through automation: further measures for increased ramping flexibility include improvements of process regulation systems, that is, the use of simulation and monitoring. Increasing the degree of automation is generally beneficial for cycling speed. For instance, fully automated drains and vents avoid operator interferences and thus accelerate start-ups and load changes. Improved monitoring and controlling systems can also hold temperature gradients within limits acceptable for all critical plant components.

- Reduce minimum load: innovative auxiliary boilers can be used as measures to reduce the minimum load levels of power plants and thereby broaden the range for the provision of primary and secondary reserve energy

- Increase criticality: within the group of steam turbine technologies, the criticality of a boiler affects the flexibility of a power plant. Supercritical boilers operate as once-through boilers in which the water and steam generated in the furnace water walls passes through only once (homogenous fluid). Steam is generated directly within the evaporation tubes of the boiler, not in the drums. Hence, the need for water/steam separation in drums is eliminated during operation and a simpler separator can be employed during start-up conditions. As units do not have thick-walled steam drums, their start-up times are quicker, thus enhancing efficiency and plant economics.

In summary, power generation entails fixed and variable costs. The fixed costs are essentially capital and land costs, which differ from region to region. Operating costs for a power plant include fuel, labour and maintenance costs. Unlike the fixed capital costs, total operating costs depend on how much electricity the plant generates and sells. Most existing coal-fired power plants were designed for operation at full or baseload to maximise efficiency, reliability, and revenue. The increased utilisation of intermittent renewable energy has resulted in a drive to increase the flexibility of coal-fired plants to cope with the intermittency of renewable power sources. Depending on the plant type and design, these facilities can adjust their output within limitations or a fixed range in response to market conditions. However, flexible operation requires more frequent start-ups and shut-downs and more aggressive ramp rates. Cycling units not designed for such operation modes can result in increased component failures, unplanned or forced outages, increased heat rate, decreased revenue and staffing challenges. In short, such operating conditions can incur major damages and costs. However, there are measures that can be taken in order to minimise the impact of such operation on the power plant including delaying the cooling down of boilers, air cooling in gas turbines, control technology through automation, reduce minimum load and increase criticality of the boiler.

4 Cost of coal power generation

In 2015, the United Nations agreed, in its Green Climate Fund, to maintain funding of modern, advanced coal-fired power plants in developing countries. The rationale for the decision is that it will help these countries ultimately fight climate change as otherwise these nations will opt for older, more polluting coal-fired technologies.

Schröder and others (2013) carried out a comprehensive survey of current and future cost estimates in the electricity sector (from mostly European literature), including renewable and conventional generation. A set of cost parameters was then derived from the various literature estimates for the period 2010-2050, which were considered appropriate for energy models and model applications for Europe. Among the various cost estimates, Schröder and others (2013) focused on the production costs, including capital costs, fixed and variable operation and maintenance costs (VOM), and other variable costs; in addition, the study provided estimates on plant availability, technical lifetime, and operational flexibility. The objective of the report is to provide a unified dataset that can be used for model comparisons. Schröder and others (2013) considered that standardisation of the cost assumptions should provide a comprehensive common dataset, and enhance modelling exercises and comparisons. In making the use of data transparent, the document aligned with the "ethical code for appropriate scientific behaviour for economists" set out by the Verein für Socialpolitik (VfS 2012) for German speaking economists, requiring, amongst other things, that research be transparent and tractable, and that data, source code, and results be made publicly available; it is also in line with the disclosure policy of the American Economic Association (AEA 2012).

The study by Schröder and others (2013) was limited to production costs and did not include other categories, such as social costs (that is, externalities such as the environment and noise but included estimates of CO_2-related costs), and transaction costs (that is, the costs of "running the institutional system", which consist of market, political, and administrative transaction costs; these can make up over 50% of total costs. Insurance costs are normally an element of the fixed costs, but are rarely reported. This is particularly distorting where no market insurance exists, such as in the case of nuclear power. Another element not addressed in the report by Schröder and others (2013) is, technology acceptance. All cost figures in the study reflect a European perspective and are expressed in 2010 €. For example, an exchange rate of €/US$1.33 and €/£0.83, € was applied to cost figures taken from the reviewed literature. A 9% discount rate and a CO_2 price of €20/t were assumed. Fuel costs considered, in €/MWh, were: 3 for uranium, 7 for biomass, 21.6 for gas (7.5 US$/MBtu), 8.4 for coal (99 US$/t) and 2.9 for lignite (10 US$/t). Efficiency rates indicated in the study refer to the most recent state-of-the-art technology in 2013.

Operating a plant below its rated capacity typically reduces the efficiency of the entire process which is expressed by the part load efficiency. The decrease in efficiency increases the fuel usage and as such generation costs. A power plant, independent of the exact technology, requires a certain amount of energy to keep the system running and synchronised, the share of which decreases with higher loads. That is, the efficiency defined as the process from fuel input to delivered load (energy output), increases with the loading of the plant. Figure 13 illustrates the relationship between the loading of the power plant, the efficiency and the efficiency loss, respectively (Schröder and others, 2013).

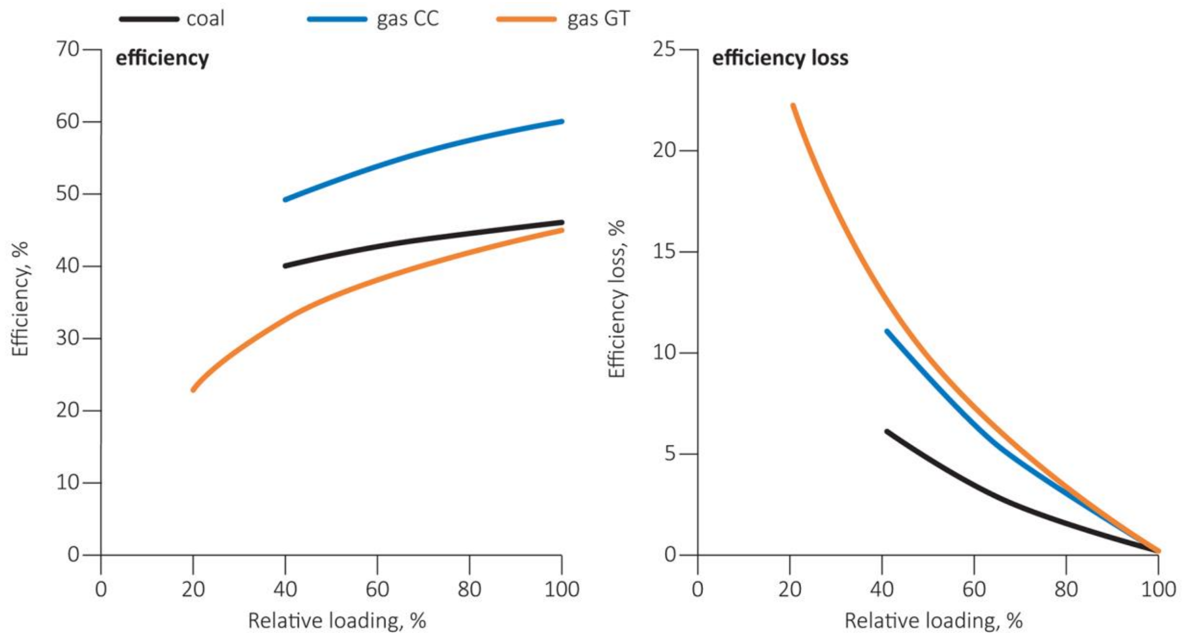


Figure 13 The relationship between plant loading, efficiency and efficiency-loss) (Schröder and others, 2013)

The Economic Research Institute for ASEAN and East Asia (ERIA, 2015) report gave a comparison of coal-fired power plant technologies, their efficiencies, CO_2 emissions and costs. Table 5 shows a cost comparison of electricity from coal-fired power generation in China, Australia, USA and the UK. Note that the given ranges are an average scenario and do not reflect actual maximum and minimum values.

Table 5 Capital, operating and levelised costs of coal power generation by country (ERIA, 2015)

Country	CAPEX[1], million US$/MWh	OPEX[2], US$/MW/year	Capacity utilisation	LCOE[3], US$/MWh
China	0.66	32,820–50,000	80	35–39
Australia	2.51–3.70	36,185–60,673	83	93–126
USA	2.94–3.11	29,670–32,820	80–85	77–78
UK	2.27–2.85	30,6000–76,500	95–98	119–172

1 CAPEX: capital expenditure: includes the total cost of developing and constructing a plant, excluding any grid-connection charges
2 OPEX: operating expenditure: is the total annual operating expenditure from initial operation, given in per unit of installed capacity
3 LCOE: levelised cost of electricity: a value that represents the total lifecycle costs of producing a MWh of power using a specific technology

It is worth noting here, as an example, an article by Yonk (2016) the subject of which is charting the unseen costs and overlooked factors that affect the cost of generating electricity from wind, solar, coal and natural gas. While most cost estimates include face-value or seen costs, such as capital, O&M and transmission, many estimates overlook the unseen costs that result from government intervention in the energy market. Yonk (2016) highlights that wind and solar power receive the majority of federal energy subsidies in the USA (*see* Table 6).

Table 6 Share of federal energy subsidies for the different electricity sources in the USA, 2013 (Yonk, 2016)

Electricity source	Subsidies, %	Generation, %
Coal	6	39
Natural gas	4	28
Nuclear	10	19.4
Solar	27	0.4
Wind	37	4.1
Other (includes renewable and non-renewable sources)	16	9
Total	**100**	**100**

It is argued that subsidies for wind and solar are necessary to help reduce costs and make renewables competitive with conventional sources of electricity. Yonk (2016) considers that subsidies do not reduce costs. They simply transfer the costs from the electricity producers to the taxpayer and end user. Thus, subsidies represent an unseen cost of generating solar and wind-based electricity that is paid not through the sale of electricity, but indirectly through taxes. Meanwhile, as wind and solar energy are intermittent and therefore unreliable, other sources of energy, such as coal-fired power plants, must be ramped up to meet demand (Yonk, 2016). Hansen and others (2016) discuss in detail the unseen costs of electricity in four reports including the unseen costs of coal-, natural gas-, wind- and solar-powered electricity. Meanwhile, in their annual energy paper on the deep decarbonisation of electricity grids, J P Morgan (2015) considered that a critical part of any analysis of high-renewable systems is the cost, which are substantial, of backup thermal power and/or storage needed to meet demand during periods of low renewable generation.

The following chapters include discussions on capital/investment costs, operation and maintenance (O&M) costs and levelised cost of electricity (LCOE) in coal-fired power generation.

4.1 Capital costs

The year 2010 capital costs and estimates to the year 2050 for various generation technologies are summarised in Table 7 (Schröder and others, 2013).

Table 7 2010 capital costs and future estimates for various generation technologies (Schröder and others, 2013)

Energy type	Capital cost, €/kW (2010)	2010	2020	2030	2040	2050
Coal	Hard coal – Advanced/Super C - w/o CCTS[1]	1300	1300	1300	1300	1300
	Hard coal – Advanced/Super C – w CCTS	2700	2624	2552	2484	2420
	Hard coal – Sub C – w/o CCTS	1200	1200	1200	1200	1200
	Hard coal – Sub C – w CCTS	2600	2524	2452	2384	2320
	Lignite – Advanced/BoA w/o CCTS	1500	1500	1500	1500	1500
	Lignite – Advanced/BoA w CCTS	2900	2824	2752	2684	2620
	Hard coal – IGCC – w/o CCTS	1800	1800	1800	1800	1800
	Hard coal – IGCC – w CCTS	3200	3124	3052	2984	2920
Gas	Gas combined cycle - w/o CCTS	800	800	800	800	800
	Gas combined cycle – w CCTS	1400	1367	1337	1308	1280
	Gas combustion turbine – w/o CCTS	400	400	400	400	400
	Gas combustion turbine – w CCTS	1000	967	937	908	880
	Gas steam turbine – w/o CCTS	400	400	400	400	400
Oil	Oil combustion turbine – w/o CCTS	400	400	400	400	400
	Oil combustion turbine – w CCTS	400	400	400	400	400
Wind	On-shore	1300	1240	1182	1127	1075
	Off-shore	3000	2742	2506	2290	2093
Solar	PV	1560	750	600	472	425
	CSP	3500	2841	2307	1872	1520
Bio	Biomass	2500	2350	2209	2076	1951
Geo	Geothermal	4200	3775	3392	3049	2740
Hydro	Pump storage or reservoir[2]	2000	2000	2000	2000	2000
	Run-of-river	3000	3000	3000	3000	3000
Marine	Wave and tidal	5000	4246	3605	3062	2600
Nuclear	Nuclear generation[3]	6000	6000	6000	6000	6000

Acronyms: Super C: Supercritical technology – Sub C: subcritical technology – w/o: without – w: with – CCTS: carbon capture, transport and storage – BoA: Braunkohlekraftwerk mit Optimierter Anlagentecnik (lignite-fired plant with optimised engineering) – IGCC: integrated gasification combined cycle – CSP: Concentrated solar power – PV: Photovoltaics

Footnotes:

1 CCTS costs reported are for 2010 although the technology as yet was not available for commercial application

2 Pump storage is in general more expensive than reservoir storage. Investment cost also depends on storage size

3 Includes decommissioning and waste disposal

Schröder and others (2013) defined the capital cost as the construction of a power plant excluding all interest effects. The authors made no assumptions about financing cost and sources of capital as these are highly specific to individual investors. The capital cost in the study was considered as the engineering, procurement and construction (EPC) cost and did not include the costs of infrastructure connections (such as, fuel, water and power grid). In addition, permission and land acquisition, as well as environmental approval requirements were not considered explicitly. Neither were the later (discounted) deconstruction of a plant costs as it was considered that the residual value of the plant covered the deconstruction cost. An exception was made for nuclear power generation, where deconstruction is more complicated and costly.

Therefore, a nuclear power plant deconstruction cost was included in the capital cost as an upfront deposit payment. The price level of cost estimates in the reviewed literature was not adjusted/reconciled, but the projections made by Schröder and others (2013) were, at the year 2010 price levels. All calculations were based on a 9% discount rate, consistent with the PRIMES energy market equilibrium model assumptions 2010. For more information on the PRIMES model *see* http://www.e3mlab.ntua.gr/.

4.2 Operation and maintenance (O&M) costs

As discussed previously, the operation and maintenance (O&M) costs of power generation have fixed and variable components. In the study by Schröder and others (2013), fixed O&M consisted primarily of plant operating labour and regular and irregular maintenance work and also included property tax, insurance and network use of system charges. Fixed O&M costs are highly dependent on the operating cycle and staffing of the plant. Variable O&M costs are due mainly to the fuel cost and to a continuous maintenance contract and include periodic inspection, replacement, repair of system components and consumables, disposal of residuals and auxiliary materials (such as, water, lubricants and fuel additives).

It is well established that the primary benefits of increasing plant efficiency are reduced emissions and fuel costs, which in coal-fired power generation are significant (~60-70% of operating cost). However, there are further benefits to improving plant efficiency on plant operation as well as profitability, including (ABB, 2009):

- better allocation: under deregulation, as utilities dispatch plants within a fleet, heat rate improvement can earn plants a better position on the dispatch list;
- avoiding a plant de-rating due to efficiency losses after pollution control retrofits or other plant design changes;
- improved fuel flexibility, by using a wider variety of fuels efficiently (coal blending) and, in some cases, increasing the firing of biomass, for example;
- improved operational flexibility, firstly by improved plant-wide integration between units which will reduce start-up/shut-down times; this benefit applies mainly to deregulated markets. Secondly, the heat rate versus capacity curve is made flatter and lower, which allows the plant to operate more efficiently across a wider load range.

Optimisation of the combustion through automation stands out as one of the most cost-effective opportunities as a best practice approach for the operation and maintenance of a furnace.

Operational changes due to improving or increasing the flexibility of a traditional and/or modern coal-fired power plant include faster load ramps, more start-ups, more frequent load changes, more frequent minimum load operation and reserve shut-down. The impacts of such operational changes on the plant O&M include increased fuel cost, increased number of thermal cycles (cycling), reduced plant efficiency, maintaining cycle chemistry, increased corrosion, increased component wear and tear and impact on downstream emissions control technology devices. The flexibility capabilities of modern, advanced coal-fired power plants include start-up times of 1–4 hours (down from 2–6 hours), minimum loads reduced from 40% down to 25% and even lower, if indirect firing is used and, improved primary frequency control times from 2–5% within 30 seconds to 10% within 10 seconds. These modern, state-of-the-art, supercritical and ultrasupercritical coal-fired power generating plants can achieve what they are built for but are significantly more expensive than standard subcritical systems (Sloss, 2016; Henderson, 2014). Sloss (2016) reviewed the impacts and costs of altering coal plant operating regimes to accommodate intermittent renewable energy production. The review discussed plant operation mode, cost penalties of flexible operation, required changes in monitoring and control as well as additional costs due to damage and increasing O&M. Schill and others (2016) studied the start-up costs of thermal power plants in markets with increasing shares of fluctuating renewables with a focus on Germany. Kumar and others (2015) also reported on the cost analysis of a coal-fired power plant using the plant lifetime net present value (NPV) method. The authors evaluated cycling costs by calculating operation, maintenance, and repair costs associated with plant cycling in India.

Lefton and Hilleman (2011) collated data from ~300 plants in the EU and North America and identified ranges of costs, noting that the actual costs of cycling a coal power plant are often higher than expected. Table 8 shows a summary of the values collected during the study. The data indicate that cold-start costs are higher than those for warm- and hot-starts. In each of these scenarios, the most cost-intensive factors occur within O&M, which can be significantly higher than expected. For example, the cycling cost for hot starts were expected to be, on average, around US$93,900 but could be as high as US$121,400. The use of monitoring and plant management systems that can predict accurately the impact of these operational modes on a plant would enable or assist in fund allocation for them in the running budget of the facility (Lefton and Hilleman, 2011).

Table 8 Typical costs for a 500 MW coal-fired power plant, in 2008 US$ (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

Power plant cycling costs in the USA were the subject of an in-depth review by Kumar and others (2012). The report was produced by Intertek APTECH for the National Renewable Energy Laboratory (NREL) and Western Electricity Coordinating Council (WECC). According to Kumar and others (2012), the median cold start-up costs are around 1.5–3 times that for hot start-up capital and maintenance costs. However, the costs for hot starts remain significant, ranging from below 40 US$/MW up to almost 180 US$/MW for smaller subcritical plants. Larger subcritical plants tend to have a lower cost range of between around 15 US$/MW and 120 US$/MW and, although the average cost for supercritical plants is around the same as for large subcritical plants at around 50–60 US$/MW, the range for the former is much narrower (~40 US$/MW to 80 US$/MW). For warm starts Kumar and others (2012) found that the costs, as expected, are higher than for hot starts, ranging up to around 280 US$/MW for smaller subcritical plants. Larger subcritical plants were found to have a significantly lower cost range for warm starts, similar to supercritical plants, indicating an advantage of a larger capacity unit, amongst other factors. For cold starts, in smaller subcritical coal plants, the costs can increase to over 400 US$/MW while the maximum cost for larger subcritical plants is ~ 200 US$/MW and for supercritical plants ~140 US$/MW (Kumar and others, 2012; Sloss, 2016).

In 2016, Kumar and others revisited the impact of plant cycling on availability and presented results of several hundred studies that highlight the impacts of plant cycling on short- and long-term plant availability. The paper also discussed the impact of plant cycling design, annual capital and operating costs, which can have a direct impact on plant availability.

The technical limits and actual costs of cycling of conventional power plants was the subject of a study by Van den Bergh and Delarue (2015). The study defines cycling as changing the output of a power plant by starting up, shutting down, ramping up or ramping down and conventional power plants as centralised and dispatchable units, such as, coal, lignite and gas-fired plants. It focuses on the cycling parameters and their impact on cycling behaviour and investigates the influence of the variability in technical parameters on the operation of power plants. For the purposes of the study, simulations were run for a low-dynamic power plant portfolio and for a high dynamic power plant portfolio. Both portfolios contained the same set of power plants, but with different cycling parameters. In the low-dynamic portfolio, the power plants had stringent cycling parameters (*see* Table 9, upper bound of minimum power output, lower bound of ramping gradients and upper bound of minimum up and down times). In the high dynamic portfolio, less constraining cycling parameters were assigned to the same set of power plants. The difference between the low and high-dynamic portfolio can be interpreted as a difference in technical characteristics of the power portfolio or as a difference in the way the portfolio is operated (for example, stringent limits reflect a more conservative mode of operation). In both portfolios, the operators face the same cost parameters for generation and cycling.

Table 9 Plants' cycling parameters (upper bound of minimum power output, lower bound of ramping gradients and upper bound of minimum up and down times) (Van den Bergh and Delarue, 2015)

Plant type	Min output, $\%P_{max}$	Ramping, $\%P_{max}$/min	Start/stop ramping, $\%P_{max}$/switch	Min up time, H	Min down time, H
Coal-fired	25–40	0.66–4	40–100	0.25–10	3–10
Lignite fired	40–60	0.66–4	60–100	0.25–10	3–10
Gas-fired	40	0.83–6	40–100	0.25–6	1–6
CCGT	30–50	0.83–10	50–100	0.25–1	0.5–6

The studied electricity generation system was based on the 2013 German system consisting of a set of conventional generation units, a demand time series, renewable generation time series and an electricity grid. The cycling of conventional units within this system was simulated by means of a dedicated operational partial equilibrium model of the power sector, that is, a unit commitment model to determine the optimal scheduling of the conventional units in order to meet residual load. The residual load was calculated as the (inelastic) electricity demand minus generation from renewables. The variability and the magnitude of the residual load both have an impact on the cycling behaviour of the conventional portfolio. Four weeks were considered in detail, reflecting all different combinations of variability and magnitude of the residual load (Van der Bergh and Delarue, 2015).

Two different sets of dynamic parameters were assigned to the same set of power plants. As discussed above, a low-dynamic portfolio and a high dynamic portfolio. Van der Bergh and Delarue (2015) found that both portfolios were able to meet the residual load (that is, the electricity demand minus generation from renewables), even up to a level where the residual load corresponds to a 50% wind and solar share. In other words, the dynamic limits of the generation portfolio as a whole were not reached. The authors also found that all types of cycling costs increase with increasing variability in the residual demand. The direct start-up cost, which is often the only cycling cost included in unit commitment models, may constitute 10-20% of the total cycling cost, though considering all cycling costs in the unit commitment scheduling can decrease the total cycling cost by up to 40%. The Van der Bergh and Delarue (2015) paper focused solely on the costs caused by cycling of a power plant in the day-ahead electricity market scenario. However, other revenue streams for a power plant operator might exist besides the day-ahead market, for example, remuneration for ancillary services or capacity payments, which, according to Van der Bergh and Delarue (2015), should also be considered in assessing the economic viability of a power plant. In conclusion, the authors consider that cycling of conventional units could be reduced by increasing the availability of other short-term flexibility options, such as electric storage, demand response, curtailment of renewable generation and increased transmission flexibility. Van der Bergh and Delarue (2015) recommend future work to address such flexibility options and investigate the reduction in cycling costs that can be achieved by deploying them.

Lew and others (2013a) discussed the cycling of conventional coal-fired power plants in the USA and conducted an operational simulation of wind and solar impacts across the entire US Western Interconnection using detailed data on cycling costs and cycling emissions. A best fit and a lower-bound and upper-bound fits for cycling cost estimates, where the bounds reflected the uncertainty range used for each plant. Lew and others (2013a) consider that while specific data from the studies were confidential, aggregated data from the studies could be used as generic wear-and-tear costs for similar units that have not been studied. Thus enabling the definition of variable operations and maintenance (VOM) costs for a hot, warm, and cold start; a ramp (typical); and for non-cyclic operation for different types of plants. Table 10 shows a summary of the lower-bound costs for the different plant types.

Table 10 Lower-bound median costs of cycling for various power generation types, US$ (Lew and others, 2013a)

	Small subcritical coal 35-299 MW	Large subcritical coal 300-900 MW	Supercritical coal 500-1300 MW	Gas combined cycle (CT-ST and HRSG)	Gas steam 50-700 MW
Hot start, US$/MW	94	59	54	35	36
Warm start, US$/MW	157	65	64	55	58
Cold start, US$/MW	147	105	104	79	75
Ramp, US$/MW	3.34	2.45	1.96	0.64	1.92
Non-cyclic operation, US$/MWh	2.82	2.68	2.96	1.02	0.92

All the cycling cost estimates used in the study by Lew and others (2013a) were for typical power generating units of various types and not unit-specific. As such, Lew and others (2013a) considered that the least suitable units for cycling are older baseload power plants that should be retrofitted prior to significant cycling, using countermeasures such as procedure and chemistry changes as well as component and hardware retrofits. Without such measures, cycling could potentially lead to costly, high-impact, low-probability events. Studies that examine the costs and benefits of retrofitting coal- and gas-fired power plants for increased flexibility continue.

The western wind and solar integration study (Phase 2) by Lew and others (2013b) was also a report produced for the National Renewable Energy Laboratory (NREL). The study focus was to evaluate the costs and emissions and simulated grid operations for a year, to investigate the detailed impact of wind and solar on the western USA fossil-fuelled fleet. The study built on Phase 1, a wind and solar integration study, which examined the operational impacts of high wind and solar penetrations in western USA. Lew and others (2013b), consider that the delivered cost of energy (DCOE) differs greatly for a fossil-fuelled plant than for a wind/solar plant, *see* Figure 14. The DCOE for a fossil-fuelled plant is a mix of fixed costs and production costs. The DCOE for a wind/solar plant is nearly all fixed capital costs. Fixed costs include power plant and transmission construction costs and fixed O&M costs. Production costs consist of fuel and VOM, which comprises cycling O&M (consisting of start fuel plus wear and tear from starts and ramps) and non-cyclic O&M (which are the routine overhauls and maintenance costs from the plant running at some steady-state output). The *only* capital costs included in production costs are capitalised maintenance (for example, more frequent boiler tube replacements) as cycling and steady state operation reduce the lifetime of such components.

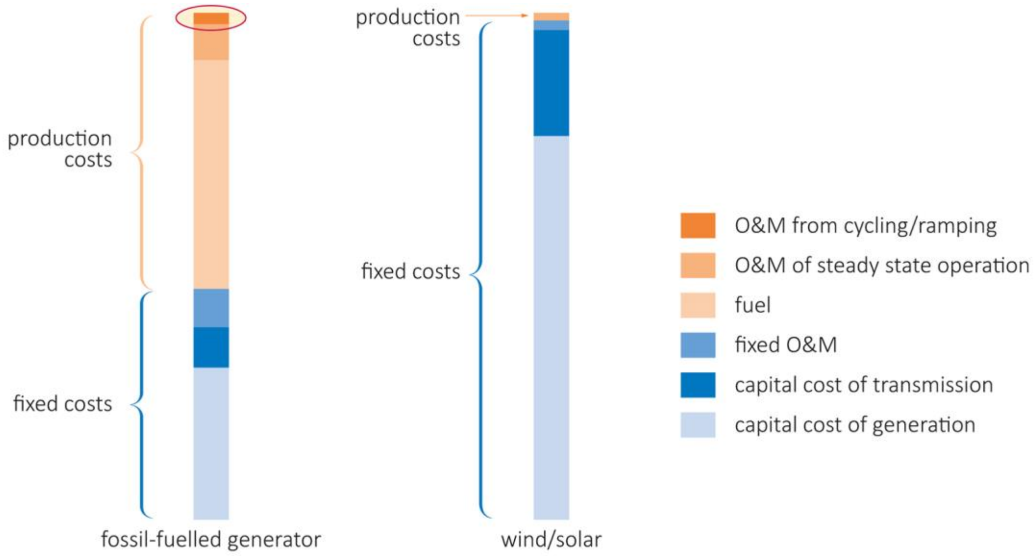


Figure 14 Illustration of delivered cost of energy (DCOE) for a fossil-fuelled plant and a wind/solar plant (Lew and others, 2013b)

Lew and others (2013b) found that frequent starts, ramping, and part-loading also impact emissions. The findings indicate that CO_2, NOx, and SO_2 emission impacts resulting from wind- and solar-induced cycling of fossil-fuelled generators are a small percentage of emissions avoided by the wind and solar generation. Cycling, induced by utilisation of solar and wind energies, has a negligible impact on avoided CO_2 emissions. Wind- and solar-induced cycling will cause SO_2 emissions reductions of 2–5% less than expected and NOx emissions reductions to be 1–2% larger than expected. Lew and others (2013b) consider that from a fossil-fuelled generator perspective, this cycling can have a positive or negative impact on CO_2, NOx, and SO_2 emission rates. Furthermore, the authors found that wind and solar energies displaced primarily gas-fired generation and increased coal ramping. Even though Lew and others (2013b) found that system-wide impacts of cycling are modest. However, as an individual unit could undergo higher than average cycling, it raises the question of whether to retrofit that unit or modify operations to better manage cycling at a lower overall cost. Research continues on potential retrofits or operational strategies to increase the flexibility of fossil-fuelled power plants, including analysis of the costs and benefits of retrofitting existing plants for options such as lower minimum generation levels or faster ramp rates. Lew (2016) considers that cycling costs, which are site specific, may impact the financial viability of a generating facility and puts these cycling costs in perspective in Figure 15. Additional analysis work that would illuminate the impacts of cycling and further compare wind and solar are listed by Lew and others (2013b).

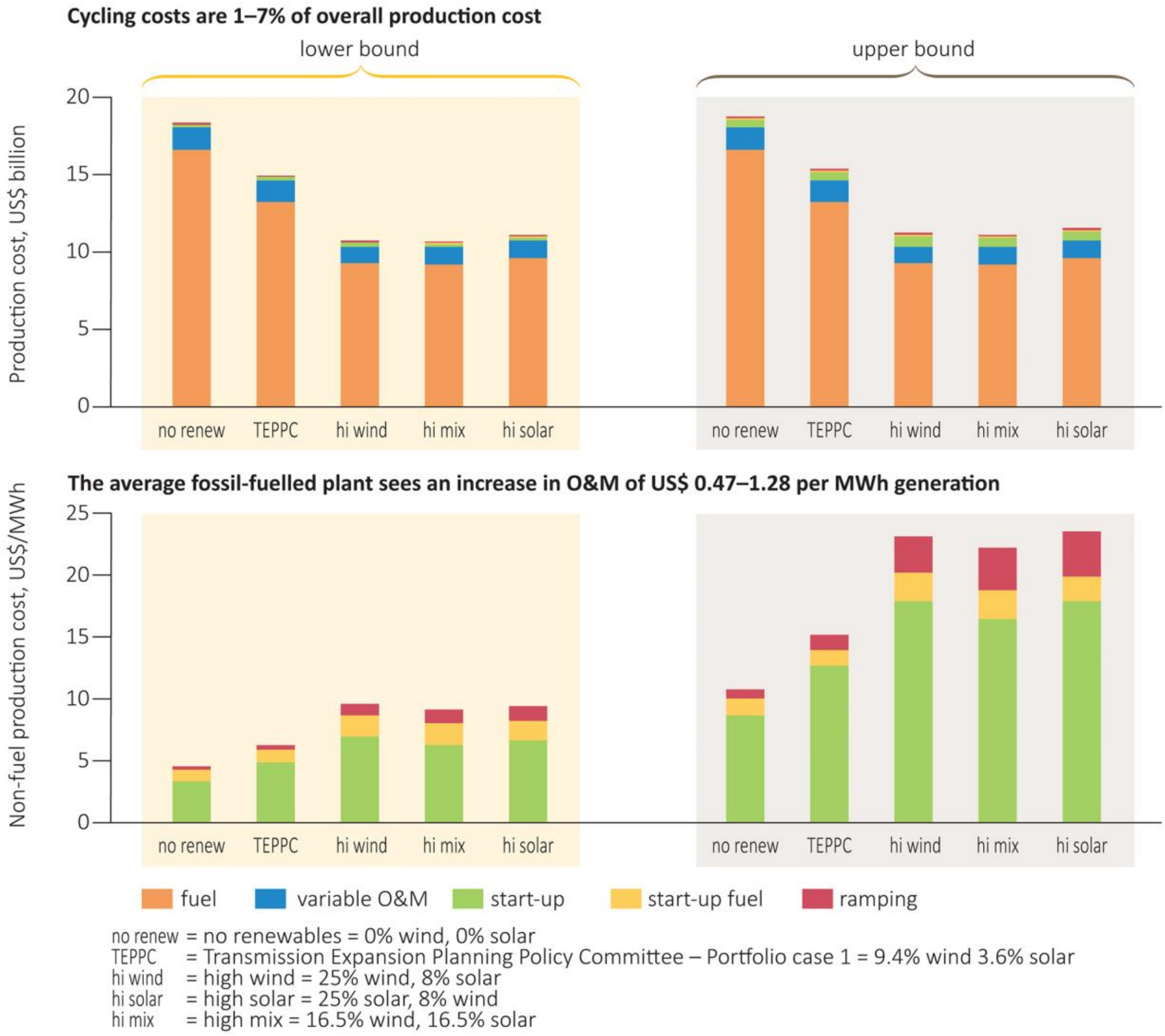


Figure 15 Cycling costs – in perspective (Lew, 2016)

In considering coal plant retirements in the USA and market impacts, Celebi (2014) summarised coal utilisation for power generation in the USA as operating capacity of 308 GW representing approximately a third of total US generating capacity. The majority of the capacity (233 GW) is owned by regulated companies and the remainder (75 GW) is owned by merchant companies. According to Celebi (2014), the majority (~93%) of the coal capacity lacks at least one major air pollution control equipment (FGD or SCR or ESP/FF).

Due to the adoption of increasingly more stringent regulations for air pollutants (SO_2, NOx, PM), mercury and CO_2 emissions, a decision has to be made to either retrofit these facilities with state-of-the-art control technologies or retire or shut them altogether. Celebi (2014) considers that capital costs are significantly greater for smaller units, and costs vary widely depending on the type of equipment needed. For major equipment such as wet FGD scrubber and SCR at a small/medium-size coal unit, costs are comparable to the cost of a new gas combined cycle unit at about 1000 US$/kW. Some units can comply with less complex technologies such as duct sorbent injection, activated carbon injection and ESP upgrades, which demand on average a total cost of about 150 US$/kW. For in-depth reviews on the different SO_2, NOx and PM control technologies visit www.iea-coal.org. Table 11 gives the capital costs of different air pollutant emissions control equipment.

Table 11 Capital costs of SO_2, NOx and PM control technologies, 2011 US$/kW (Celebi, 2014)			
Control technology	**50 MW unit, US$/kW**	**200 MW unit, US$/kW**	**600 MW unit, US$/kW**
Wet FGD scrubber	904	734	513
Spray Dry FGD scrubber	774	628	448
Duct sorbent injection	42	39	39
Selective catalytic reduction	273	234	188
Selective non-catalytic reduction	51	51	51
Fabric filtration/baghouse	504	387	219
Activated carbon injection	29	27	19

Celebi (2014) found that the levelised all-in cost, including capital, fixed operation costs (FOM) and variable operation costs (VOM), of some control technology equipment for a 200 MW coal unit could be as high as 50 US$/MWh depending on capacity factor and type of equipment (*see* Table 12).

Table 12 Levelised costs of SO_2, NOx and PM control technologies, US$/MWh (Celebi, 2014) (200 MW unit, 15-year recovery, and 15% capital charge rate)		
Control technology	**Capacity factor (30%), US$/MWh**	**Capacity factor (70%), US$/MWh**
Wet FGD scrubber	50.80	22.91
Spray dry FGD scrubber	43.57	20.13
Duct sorbent injection	10.10	8.15
Selective catalytic reduction	15.40	7.37
Selective non-catalytic reduction	4.38	2.48
Fabric filtration/baghouse	23.25	9.98
Activated carbon injection	2.88	1.91

According to Celebi (2014), wholesale power prices in 2013 continued to be low in regions with significant coal-based power generation due to low gas prices and depressed load conditions, although they were higher than 2012 prices. In addition, forecast/projected markets show very moderate LCOE price growth to 2020, potentially improving coal plant margins. It is worth noting here that a significant number of plant retirements is due to the US Clean Power Plan (CPP) requirements for reductions in CO_2 emissions. However, according to the EIA (2016), energy-related CO_2 emissions from natural gas are expected to surpass coal in 2016 by 10%, as fuel use patterns change.

4.2.1 Outsourcing O&M

Power plants traditionally arranged contracts with original equipment manufacturers (OEM), equipment, procurement and construction (EPC) companies, maintenance contracting companies and consultants to assist with the major plant outages while in-house staff were generally responsible for routine and minor/standard outage maintenance work. Controlling the costs of O&M including materials/components management and inventory control are major concerns for all power generating companies. The impact of cycling on plant outages and increased maintenance requirements can be significant, as discussed above. In addition, the increasing competition in the electricity market has affected staffing levels, whether due to cost of labour or a drive to greater efficiency. As a result, plant operators began outsourcing some or all of their plant maintenance and materials management. More so in the USA for example, compared to some countries in Asia, such as India. Where some or all O&M services are outsourced, it is important that the service contracts define all operational and maintenance activities that address efficient plant operation including tracking operating changes, improvements, deficiencies over time and keeping a record of activities to detect and troubleshoot maintenance and operational problems. The records would provide staff and management with critical data for comparing historical and current conditions in the plant equipment, components and performance. Taking a tracking preventive maintenance approach would also assist plant personnel in locating recurring problems, understand when equipment performance is degrading, and ensure that the O&M contractor performs the tasks according to the contract.

Companies that sell their O&M services or power plant OEMs that offer O&M contract services can provide a plant manager with a wide range of services, including (MacDonald, 2002):

- **inventory**: procure all parts and accessories for a plant; manage and place orders on behalf of the operator to acquire inventory; and maintain the inventory for the plant;
- **manuals:** develop various manuals for the plant, tailoring generic manuals to meet specific needs of a plant with respect to safety, emergency, administrative and O&M procedures. This should be a joint effort between the plant permanent personnel and the service contractor staff, in which overall company rules are implemented and modified according to the specific plant needs, or location;
- **planning and budgeting**: develop an operating plan and budget with the plant manager, prior to commencing commercial operation at the plant, and repeating the process on an annual basis, for company approval;
- **permits and licenses:** obtain and maintain validity of government and regulatory agency permits for the commissioning, testing, start-up, operation, and maintenance of the plant;
- **plant start-up**: assist the project EPC contractor with facility start-up; supply O&M personnel during the commissioning period; and, during this period, provide training to the plant permanent personnel;
- monitoring and control: monitor fuel consumption continuously and estimate fuel requirements during plant operation; and provide the plant owner with schedules to track fuel usage;
- preventive maintenance: provide O&M technicians that are trained to accomplish preventive and routine maintenance of plant equipment; implement a preventive maintenance programme including regular inspection, testing, calibration, and servicing of equipment used in the power plant; and prepare reporting systems for scheduling and tracking services that need to be performed, while identifying potential problems that may occur;
- management plan: use its own plant management plan to combine all functions required, such as inventory control, generation of automatic work and purchase orders, preventive maintenance and

predictive analysis scheduling, equipment failure analysis, budget support, and generation of analysis reports. This can help an O&M contractor reduce substantially forced and scheduled outage times, increasing plant availability, reliability, and overall facility efficiency by identifying minor equipment and system problems and addressing them before they become major, or too costly.

In an evaluation of outsourcing decisions for power station O&M services, Mercer (2009) studied the use of the Analytical Hierarchy Process (AHP) as a modelling tool, which uses a hierarchal structure to sort both tangible and intangible criteria in O&M based on their relative importance, with a pairwise comparisons between each criterion. The methodology allows a complex model to be rapidly decomposed and assessed. The system is simple, robust and proven in many industries, making it a useful method for asset owners to assess their outsourcing decisions. Mercer (2009) considers that while certain generalities can be made, there is no '*one size fits all*' package for O&M services. Each power generating company needs to perform its own evaluation for plant asset management based on its own competences, strengths and corporate strategy. For details on the modelling in the study see Mercer (2009).

Mercer (2009) found that the results obtained from industry use-cases were comparable to actual experience. The tendency of a large utility would be, as expected. to prefer internal supply or minimal outsourcing whereas an independent power producer (IPP) with little experience would be expected to favour a more comprehensive level of outsourcing. The overall results, as summarised in Figure 16, show this result based on a logical analysis on all key criteria. However, with increasing competition in the 21st century, some utilities have opted to outsource more, and in some cases all, of their maintenance requirements. With increasing focus on asset management and the generation and sale of energy, outsourcing power plant equipment maintenance to third parties is on the increase.

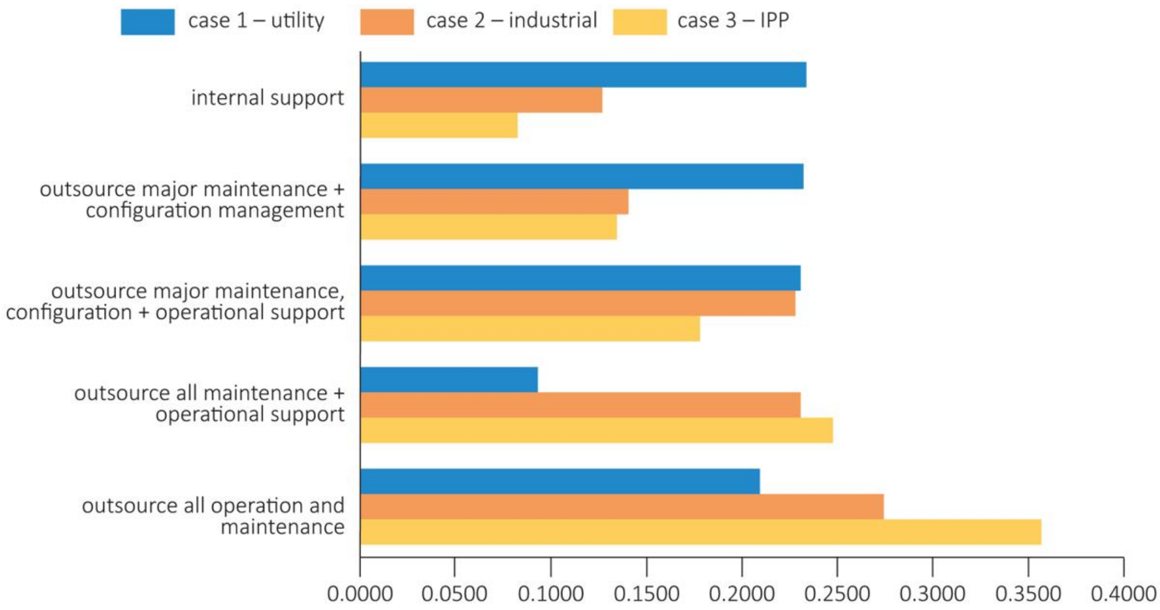


Figure 16 Summary of alternative preferences in all use cases (Mercer, 2009)

Smith (2004) considered that a larger percentage of the contracts were being awarded externally to the OEMs and EPC contractors. Advantages of outsourcing to OEMs and EPC contractors include knowledge of the entire power plant and the ability to provide materials management. This not only allows a power plant to reduce inventory costs, it can reduce equipment downtime. As OEMs have, in general, large inventories of parts they can usually deliver the parts quickly. In addition, depending upon the risks, an outsource contract can include performance-based guarantees tied to the duration of the planned outages, equipment availability and heat rate of the plant. According to Smith (2004) there are six major steps in maintenance management including work identification, work planning, work scheduling, work execution, history recording and finally analysis. A power plant may outsource the work execution while carrying out the work identification, planning, scheduling, analysis and record keeping in-house. Another alternative is for plant personnel to analyse and identify what work should be done and outsource the remainder. On the other hand, some plants may decide to outsource all the maintenance including preventive and predictive maintenance. Issues that should be addressed by a utility considering a long-term outsourcing contract include (Smith, 2004):

- Personnel: whether the utility will lay-off any personnel and if so will they be re-employed by the contractor?
- Plans/drawings: who has the responsibility for ensuring that plans/drawings are kept up to date and who will be the custodian of on-site plans/drawings?
- Computer systems: will the contractor have access to the utility computerised maintenance system or will they have their own system? Who will be responsible for ensuring the input and accuracy of all the data?
- Materials management: will the contractor provide all materials and parts or will the utility have this responsibility?
- Workshop facilities and tools: who owns and maintains these?

Smith (2004) recommends that utilities have all of their questions answered before signing a contract. Agreeing the issues and resolving any problems upfront makes the transition from in-house to outsourcing a plant's O&M easier and more satisfactory to both the utility and the contractor.

The O&M outsourcing market in India is in its early stages. Traditionally, O&M and project management consultancy (PMC) activities in medium to large power plants was largely carried out by plant personnel.

In recent years, with increasing demand for electricity and with the opening up of the electricity sector, private power generating companies have constructed and are operating power plants in India. This has resulted in opening up the market for O&M outsourcing. AFS Action (2014) estimated that an approximate capacity of 15 GW had already outsourced their O&M services. AFS Action also forecast that, by 2016/17, approximately a further 12 GW of capacity is expected to require outsourced O&M services. However, the completion of projects that are currently facing problems on numerous counts remains the key to the successful growth of this segment of the industry in India. The flexibility requirements in the Indian power sector was the subject of an in depth report by Power System Operation Corporation Limited (POSOCO, 2016). Meanwhile, in August 2016, Uniper (E.ON group) announced entering into a 50-50 joint venture with India Power Corporation Limited (IPCL), India Uniper Power Services, which will offer customised services to customers in the Indian power business. These would include plant O&M, asset monitoring software and analytical tools, improving the flexibility of units, lifecycle extension as well as supply and integration of pollution control equipment and systems (Enerdata, 2016).

Kulkarni and others (2013) discussed a new trend in outsourcing operations by IPPs in India. The increasing fuel cost combined with the newly adopted strict regulatory emission standards as well as tariff-based bidding are exerting pressure on IPPs to focus on improving operational efficiency by increasing plant availability, reducing operational costs, increasing plant load factor and becoming overall more competitive, especially with regard to cost. This has resulted in evaluating O&M options including outsourcing. As discussed previously, inadequate O&M can have multiple impacts on performance including reducing plant availability, causing higher station heat rate (SHR), higher auxiliary power consumption and subsequently reduced profit. Kulkarni and others (2013) show the impact of a poor O&M strategy on a project's internal rate of return (IRR) for a 1300 MW power plant in Figure 17. IRR can be defined as the rate of return that makes the net present value of all cash flows equal to zero. Figure 17 shows that a 5% decrease in availability can reduce project returns by more than 17% and a 1% increase in auxiliary power consumption can potentially reduce project IRR by 6%. In a worst case scenario, Kulkarni and others (2013) consider that poor O&M can lead to >27% reduction in project returns and as such, IPPs need to decide on in-house O&M or outsourcing.

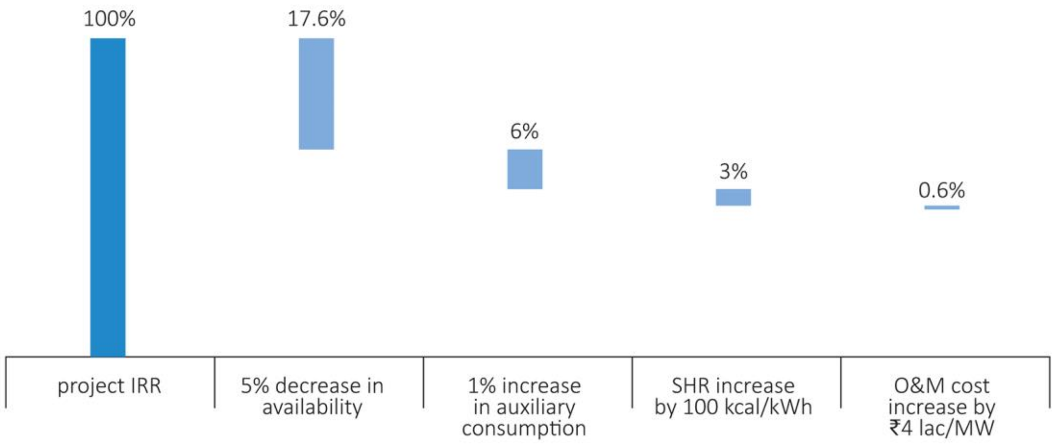


Figure 17 Impact of a poor O&M strategy on a project IRR (for a 1300 MW power plant) (Kulkarni and others, 2013)

However, according to Kulkarni and others (2013), with limited availability of a skilled labour force and difficulties in attracting and retaining knowledge and talent at remote locations, IPPs are facing O&M related challenges. Hence, outsourcing of O&M has become a growing trend. However, it is essential to understand the core competencies within the IPP and evaluate different outsourcing options before deciding upon an O&M strategy. Figure 18 shows the four predominant types of O&M strategies followed by IPPs; maintenance outsourcing, basic O&M outsourcing, enhanced O&M outsourcing and complete O&M outsourcing.

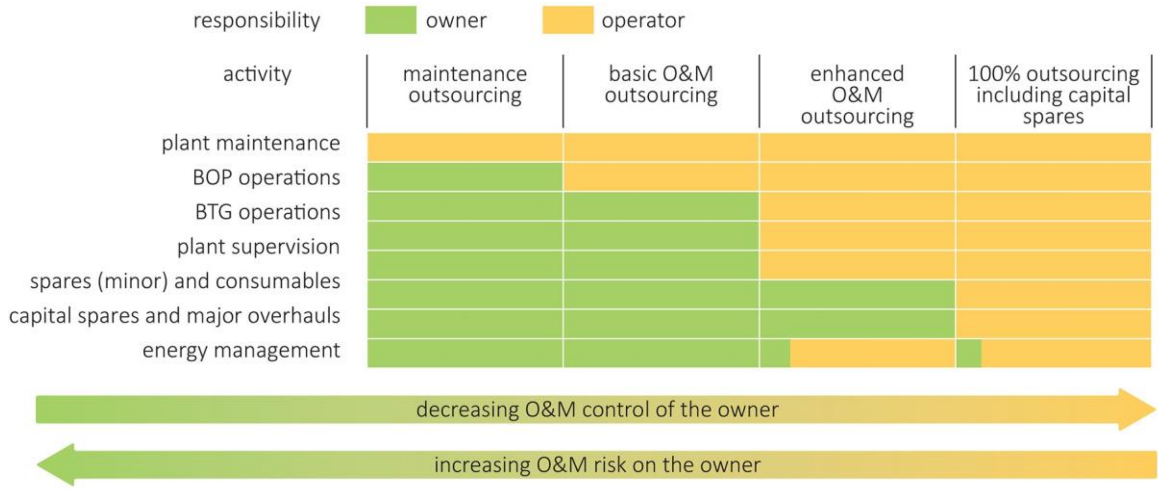


Figure 18 The four predominant types of O&M strategies (models) followed by IPPs (Kulkarni and others, 2013)

The level of O&M outsourcing varies across the different models and is also a function of the IPP experience and capabilities. Maintenance outsourcing involves plant maintenance only being outsourced and plant operations to be carried out by an in-house team. Basic O&M outsourcing includes outsourcing both maintenance as well as balance of plant (BOP) operations. Enhanced O&M outsourcing includes boiler, turbine, and generator (BTG) operations, plant supervision and spares being outsourced as well as the plant maintenance and BOP operations. The advanced type of O&M outsourcing is complete outsourcing wherein everything is outsourced except energy management supervision. Kulkarni and others (2013) consider that each O&M strategy has pros and cons. For example, while maintenance outsourcing provides more control to the owner, the owner is exposed to operational risks. Although, the complete O&M outsourcing strategy reduces the operational risks to the owner, it comes at a cost. An established power generator could consider maintenance outsourcing but a new IPP with limited experience in in-house operations capabilities may find that difficult, especially given that hiring, training and retaining skilled manpower for O&M is a serious challenge for the new IPPs in the current scenario of the power sector in India. New IPPs could concentrate on the core activities such as financing, fuel sourcing, construction, power sale and outsource the non-core activities of O&M. Such IPPs could adopt either the complete outsourcing or enhanced O&M outsourcing model. Relatively more established IPPs could retain control over key BTG operations and develop a strong overall BTG O&M team while outsourcing labour intensive O&M of BOP, for example, the coal handling facility, the ash handling system and water treatment plant which can be referred to as the basic O&M model. (Kulkarni and others, 2013).

MacDonald (2002) presented the advantages and disadvantages of outsourcing O&M services and the necessity of evaluating those as well as other parameters such as personnel and costs prior to the outsourcing. The biggest advantage of outsourcing a power plant's O&M services, according to MacDonald (2002) is flexibility, as outsourcing enables a power plant manager to recruit and dissolve a large workforce quickly and on demand which can be a considerably more difficult task with an in-house workforce. Other specific advantages include (MacDonald, 2002):

- the ability to fluctuate workforce use to meet the exact day to day facility needs;
- allows the use of fewer workers per year to perform a given amount of work;
- eliminates the employment of full-time personnel to handle peaks;
- requires less training of in-house staff as contract service personnel should be already trained;
- provides a power plant manager with unlimited worker availability thereby enabling the scheduling of turnarounds, overhauls, and alterations to best fit a facility's overall economics and needs, rather than having to fit these requirements to the availability of a given number of facility in-house staff; and reduces equipment and systems downtime by using more personnel, where necessary;
- passes on to the contractor the responsibility for essentially all or a significant part of a facility's O&M services, leaving the power plant's key personnel more time to concentrate on overall plant management;
- can provide a power plant manager with services beyond normal O&M tasks, including: additional supervision as needed for the provided services; intermittent supervision in specialty areas such as critical equipment inspection, and repair; and, in some instances, task planning and estimating, equipment tests, construction drawing take offs, and so forth;
- enables a power plant manager to start with an O&M service contractor and, if not satisfied with the results, replace the contractor or phase the power plant's O&M work into an in-house organisation.

After evaluating and determining the benefits of outsourcing O&M work, the following considerations and disadvantages should be evaluated (McDonald, 2002):

- the legal aspect of contracting O&M services;
- the financial aspect of contracting O&M services, for example, wage rates. If the cost of the outsourced O&M services exceeds the facility's in-house cost, power plant managers cannot, or will not, be able to afford the contracted O&M services;
- monitoring of peak staffing during periods of O&M construction work;
- specialty support; some O&M contractors cannot provide sufficient skills or supervision without support backup from plant personnel.

MacDonald (2002) considered that if the overall evaluation of costs and benefits indicate that outsourcing O&M offers a distinct advantage, further evaluation must be undertaken to decide on which alternative outsourcing option to implement. These include:

- an in-house workforce that performs all O&M work, both day to day requirements and peak loads with some specialty requirements contracted out;
- an in-house workforce that performs all day to day normal requirements but retain an O&M service contractor's workforce to handle major peaks such as emergencies, turnarounds, overhauls, and the like;

- a minimum in-house workforce that performs only part of the day to day requirements/maintenance; using a contractor's O&M services to perform the balance of day to day work and to handle peak requirements; or
- no in-house O&M personnel and rely entirely on a contractor's workforce to provide all the O&M personnel for normal as well as for peak O&M needs.

The last alternative, according to MacDonald (2002) should be the exception rather than the rule as studies have repeatedly shown it to be more efficient to have at least a small number of in-house personnel to provide basic O&M services, preventive and predictive maintenance procedures, and energy management control systems operations and programming. Once a decision has been made on the type of outsourcing services, the operator then must determine who can best provide the O&M services for the power plant. This involves evaluating the capabilities of the in-house O&M personnel with those of the prospective O&M service provider, carefully examining the experience level of the outsourced O&M services provider by questioning how long has the contractor been in business, how many power plants does the contractor operate, what types of facilities does the contractor operate, and where are they located? Are they similar to the plant under consideration, what has been the contractor's performance record at those plants? Are the contractor's existing customers satisfied and has the O&M contractor ever defaulted on a contract? Is the contracted staff knowledge and experience adequate to support an O&M project workforce? Whether the contractor has the necessary equipment, tools, and facilities to support the plant's operations and the knowledge to work in line with the labour force regulatory requirements wherever that may be? Further considerations include evaluating the capabilities, skills, knowledge, background and experience of the project management team.

In brief, in selecting an O&M services provider, MacDonald (2002) considered that power plant operators should base their decisions on a proposed long-term contractual agreement that takes into consideration the contractor's reputation, experience, performance record, scope of services required, capabilities to supervise, skills of the contract workforce, labour relations, and of course price.

In a study published in 2011, Frost and Sullivan found that despite the potential market in Asia Pacific, there are only limited O&M outsourcing opportunities, as these tasks are normally undertaken by the in-house staff of power plants. Power plants in the region continue to view power generation and operation as their core business and seldom outsourced these functions to service providers. Most power plant owners in the region perceive long-term service agreements with OEMs as costly, incommensurate with the value it offers. Hence, in many cases, power plant owners undertake maintenance and repair services through open tenders, on a transactional basis. Although power plants are mostly reluctant to relinquish control over O&M, utilities do see some merit in outsourcing power plant servicing to its subsidiary service companies. Frost and Sullivan (2011) consider that the expanding presence of IPPs in the power generating market and the mounting pressure on utilities to decrease operating costs are likely to enhance outsourcing opportunities over the following six to seven years. The market is expected to expand once technically advanced power generating equipment gets deployed across greenfield, brownfield and repowering power plants (Frost and Sullivan, 2011). In their study of global power plant services markets Frost and Sullivan (2015) found that although power plants in the USA and Europe outsource a large portion of their servicing in coal-fired power generation owing to the shortage of skilled labour, operators in ASEAN countries prefer in-house maintenance for their lower costs. Frost and Sullivan consider that in order to enter regional markets and broaden their services, global OEMs are likely to acquire or merge with local and regional service providers (Frost and Sullivan, 2015).

4.2.2 Cost analysis with automation

Throughout the previous chapters, automation was mentioned as a tool gaining wider use in order to improve O&M and efficiency as well as reduce the emissions and costs of coal-fired power generation. Power plants today incorporate digital/distributed control systems (DCS), process optimisation systems, including neural networks, advanced graphics and simulation as well as performance monitoring software, internally and externally. In addition, some coal-fired power plants are using predictive maintenance techniques and online stress calculators and as such reducing spare part inventories and extending the intervals between scheduled outages to reduce costs. Online analysis and the utilisation of expert systems in coal fired power plant were discussed by Nalbandian (2005, 2011) In addition, instrumentation and control and their upgrades were the subject of two reviews from the IEA CCC by Nalbandian (2001, 2004) More recently, Lockwood (2015) reviewed sensors and smart controls for coal-fired power plant.

In addition, as previously discussed, cycling, or varying the load level of a coal-fired unit, including starts, ramping or load following, and operation at minimum load, can cause thermal and pressure stresses in the boiler, steam line, turbine, and auxiliary components. These stresses can accelerate wear and tear in the various systems in the unit and therefore, can result in increased capital and maintenance costs and/or reduce the life expectancy for components that may increase equivalent forced outage rates (EFOR). In addition, varying the load level over prolonged periods can degrade a unit's fuel conversion efficiency (that is, heat rate). However, cycling related wear and tear mechanisms are complex and often involve multiyear time lagging (that is, a period or interval of time between two related phenomena/actions (such as, a cause and its effect)). As these effects are difficult to assess, utilities, until recently, have not quantified the costs or impacts related to cycling. In 2012, Intertek APTECH developed such data for the NREL and the WECC. A description of the wear and tear cost data is discussed previously in this review but for greater detail *see* Kumar and others (2012). The Intertek COSTCOM® is a software product that is designed to be added to the existing generation of power plant DCS. The software computes damage accumulation rates and US$ costs for specific types of cycling operations. This is achieved by drawing real-time measurements from the DCS and computing actual stresses and damage accumulation. The software determines the cost impacts of increasing ramp rates, capacity (MW) load transient ranges, and shortened start-up times. Using the software assists the operators in controlling cycling operations to reduce costs (Intertek, 2016).

Asset management systems for power generation may be able to reduce operations risk. An accurate, high definition system with an ability to evaluate the medium- to long-term generation programme of a company can achieve an estimation of operating costs, including those resulting from cycling, and maximum potential profits. Kumar and others (2013) reported on ‘smart asset management: using real time transient data to determine equipment damage, maintenance costs, and operations strategy in power plants’ in which, real time monitoring and analysis of data was carried out. Lefton (2012) presented cost analysis and power plant asset management and thermal power plant cycling costs. He defined and summarised the different phases of cycling a unit and highlighted the increased risk of damage through each phase (*see* Figure 19). Where plant shut-down occurs, the start-up conditions, hot, warm or cold, will depend on how long the plant is offline. The colder the plant before start-up, the greater is the increased risk of damage to the plant. Figure 20 shows a typical cycling cost breakdown in a large coal-fired unit (Lefton, 2012).

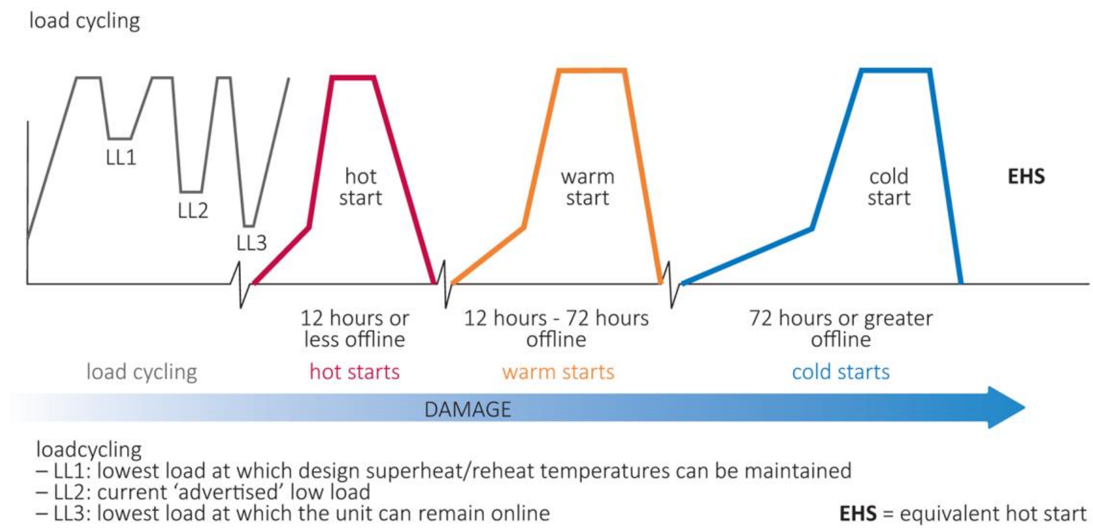


Figure 19 Power generating unit cycling definitions and effect (that is, relative damage) of load cycling (Lefton, 2012)

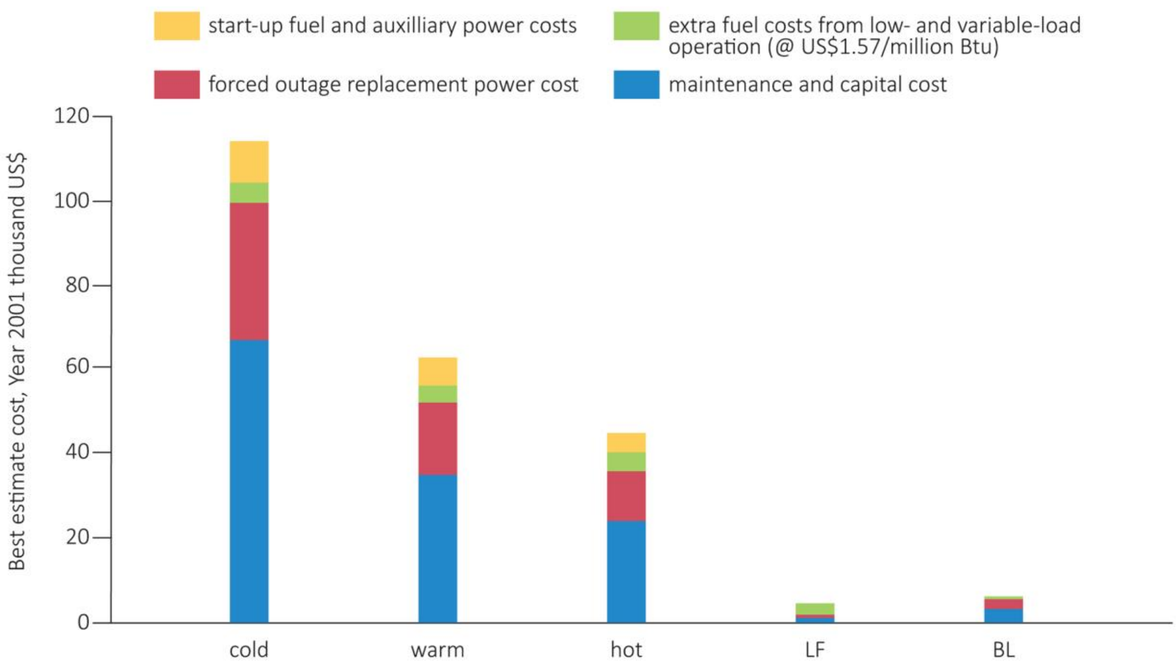


Figure 20 Typical cycling cost breakdown for a large coal-fired unit (Lefton, 2012)

The damage caused by cycling may not be immediately apparent and can often take several years before manifestation. Studies carried out by Intertek APTECH suggest that it can take 1–7 years for evident increases in the failure rate following the switch from baseload operation to cycling operation. Intertek APTECH have carried out and taken part in numerous studies and analyses on cost of cycling for coal-fired power generation including Cochran and others (2013 and 2014), Kumar and others (2012 and 2013), Lefton (2012), Lefton and Hellman (2011), Danneman and Lefton (2009), Lefton and Besuner (2006) and many more.

An example of modern, advanced use of automation in coal-fired power plant solutions is the GE (USA) digital twin concept (World Coal, 2016). The approach is to take data on the construction, operation, maintenance, thermal performance, among other parameters of the power plant and combine them with data from thousands of sensor inputs across the plant, weather data, market information and any other relevant data to form a complete picture of the equipment. The exercise allows operators to understand how to run a power plant to best meet their operating context. The digital twin concept was made possible by Predix (https://www.ge.com/digital/predix), the GE cloud platform for the industrial internet, which was launched recently. Predix is a platform for industrial-scale analytics, which connects machines, sensors, control systems and devices to capture and interpret data from production systems such as coal-fired power plants. Predix aims to improve asset reliability, lower operating costs, reduce risk and help drive profitable growth. GE digital is in the process of forming partnerships/alliances with a number of organisations. One such example is the newly formed, PwC and GE digital alliance, which combines the capabilities of the two organisations to provide power companies with tools to transform into digital enterprises and improve their business outcomes. PwC is the brand under which the member firms of PricewaterhouseCoopers International Limited (PwCIL) operate and provide their services. The alliance promises to help power companies navigate a complex market while delivering end-to-end industrial internet solutions and business transformation services. It develops and provides solutions based on the GE digital Predix operating system and helps power companies across three dimensions (*see* Figure 21). In addition to leveraging a suite of GE digital applications and solutions (including Predix), PwC and GE digital build customised applications based on each plant's unique needs.

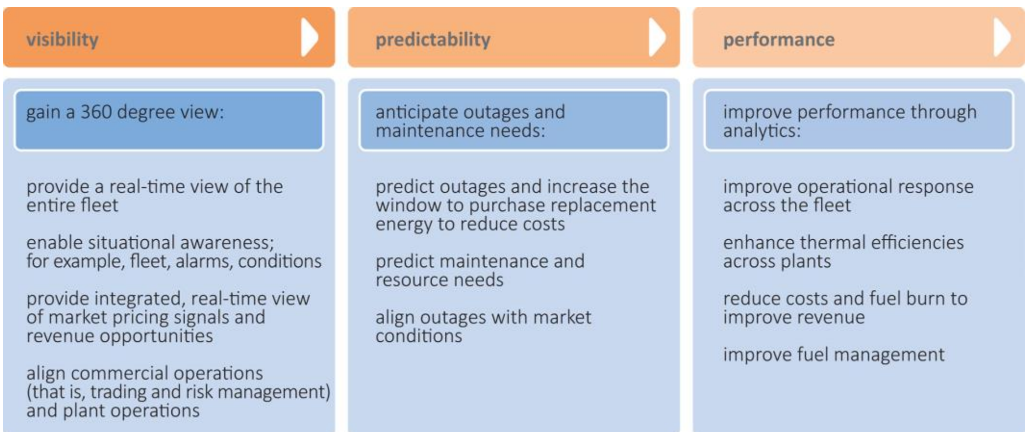


Figure 21 Benefits of implementing the PwC and GE Digital alliance approach in the power generating industry (PwC, 2016)

The GE digital solutions suite includes the asset performance management for power, operations optimisation, cyber security for power, advanced control/edge computing and Predix. Powering the digital transformation of electricity using the components of the GE digital solutions suite was the subject of a report by GE Power (2016a). Experiences with the GE digital solutions and, digital transformation of power generation, including cost savings, improved overall operational performance, continued analysis and monitoring of the system as well as reduction in emissions, are discussed in detail on the GE webpage http://www.ge.com/digital/industries/power-utility/power-generation. On the 20 September 2016, GE Power (2016b) announced > US$800 million in new digital industrial power orders across the Asia-Pacific region to provide more efficient, reliable and sustainable solutions as well as reduce environmental impacts and lower costs through the digital transformation of electricity.

The benefits of digitisation in coal-fired plants was the subject of a GE (2016c) white paper entitled 'Powering India'. The report looks at a whole power plant at the system level and explores the means to address the overall plant key performance indicators (KPIs) from the coal yard to the stack by using information captured by sensors across the system and, with the use of advanced analytics, provide real time insights. The approach is purported to enable better operation of the power plant and help in achieving improved performance, reliability and availability leading to reduced emissions and increased profitability. The paper considers the size of the current installed and additional, planned coal-fired capacity for the future in India and how a marginal improvement of 1% in performance and efficiency can have a potential impact of US$5 billion over a 30-year life span. To calculate the potential benefits, GE (2016c) assumes the average plant heat rate for a typical 200 MW coal-fired plant in India to be 2400 kcal/kWh. Assuming, the same heat rate for India's total installed capacity of 185 GW, 1% reduction in heat rate would have a significant impact on savings of the plant as shown in Figure 22.

Figure 22 Typical impact of 1% heat rate on a coal-fired plant in India (GE, 2016c)

A modern coal-fired power plant relies on a complex network of sensors, actuators, digital controllers, and supervisory computers to operate and coordinate each of the plant subsystems. Numerous feedback control loops serve to monitor the plant processes and perform appropriate control actions, aiming to maintain optimum operating conditions regardless of system disturbances such as changes in coal quality or load demand. A digitalised analytical system has greater capability to respond to the highly interrelated parameters of a power plant and enables closer control and reaction to changes by having immediate access to the data from the complex system components. The paper presents the GE digital power plant application suites, including asset performance management, operations optimisation and business optimisation. These applications monitor thermal performance, improve plant operation as well as reduce emissions and maintenance costs while the so-called GE digital twin system, an organised collection of physics-based methods and advanced analytics, is used to model the present state of every asset in a digital power plant and deliver mechanisms to solve plant problems (GE, 2016c).

4.3 Levelised cost of electricity (LCOE)

The levelised cost of electricity (LCOE) is the price required per unit of output as payment for producing power in order to reach a specified financial return. In other words, it is the price that a power plant must earn per MWh in order to break even. A LCOE calculation standardises the units of measuring the lifecycle costs of producing electricity and as such facilitates the comparison of the cost of producing one MWh by different technologies. The simple formula for calculating LCOE is shown below and is denominated in US$/MWh.

$$\frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

Where I_t is investment expenditures in year t (including financing), M_t is O&M expenditures in year t, F_t is the fuel expenditures in year t, E_t is electricity generation in year t, r is the discount rate and n is the life of the plant.

The World Energy Council (WEC) and Bloomberg New Energy Finance produced a comprehensive comparative study of the costs of producing electricity from a wide range of conventional and non-conventional sources. The aim of the study was to provide reference costs based on actual project data, focussing on leading renewables and conventional technologies across a range of regions worldwide.

The LCOEs for the WEC (2013) report were calculated using a discounted cash flow (DCF) model, which allowed the capture of the cost impact of the timing of cash flows, development and construction costs, multiple stages of financing and interest and tax implications of long-term debt instruments and depreciation, among other factors. The LCOEs in the report reflect the actual costs of each technology and exclude all subsidies and support mechanisms. This facilitates a comparison of the total costs of each technology on an equal basis, but does not represent the net costs faced by developers in the market. The costs used by WEC (2013) reflect the then most recent data available and exclude the expense of connecting to the grid, balancing costs and the cost of maintaining adequate flexible capacity in the electricity system to ensure continuous supply as more intermittent, renewable, capacity increases. Figure 23 shows the LCOE for coal- and gas-fired energy over time, developed market average (US$/MWh) and Figure 24 illustrates the LCOE for coal-based energy for four countries including; Australia, China, the UK and the USA (WEC, 2013). The capital, operating and LCOE costs for coal-based energy for the same four countries were given in Table 5 above (ERIA, 2015).

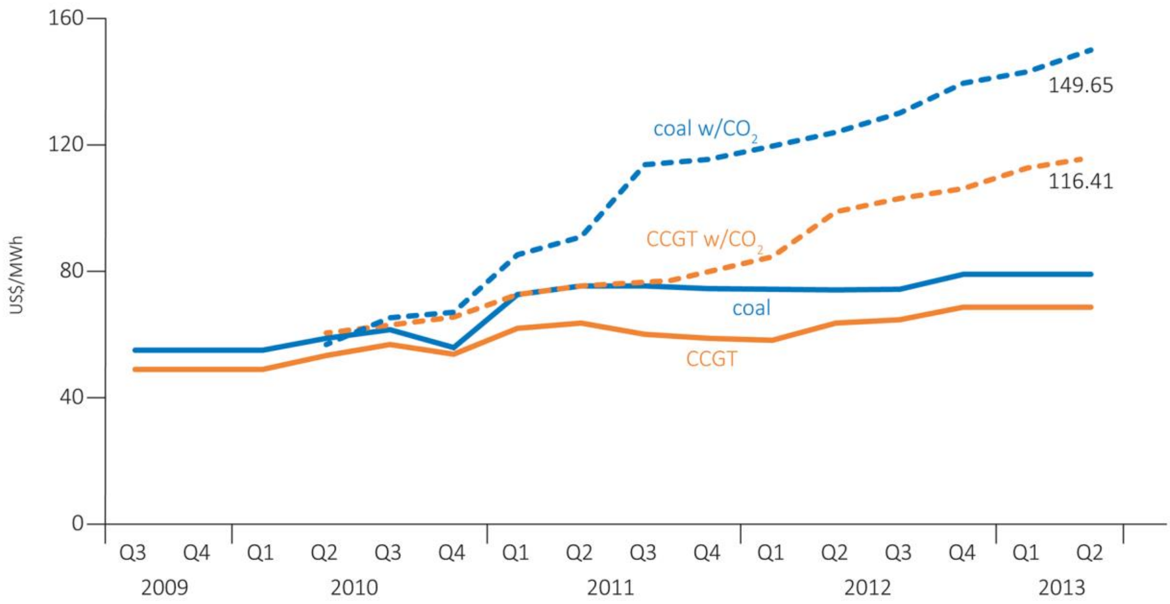


Figure 23 The LCOE for coal- and gas-fired energy over time, developed market average, US$/MWh (WEC, 2013)

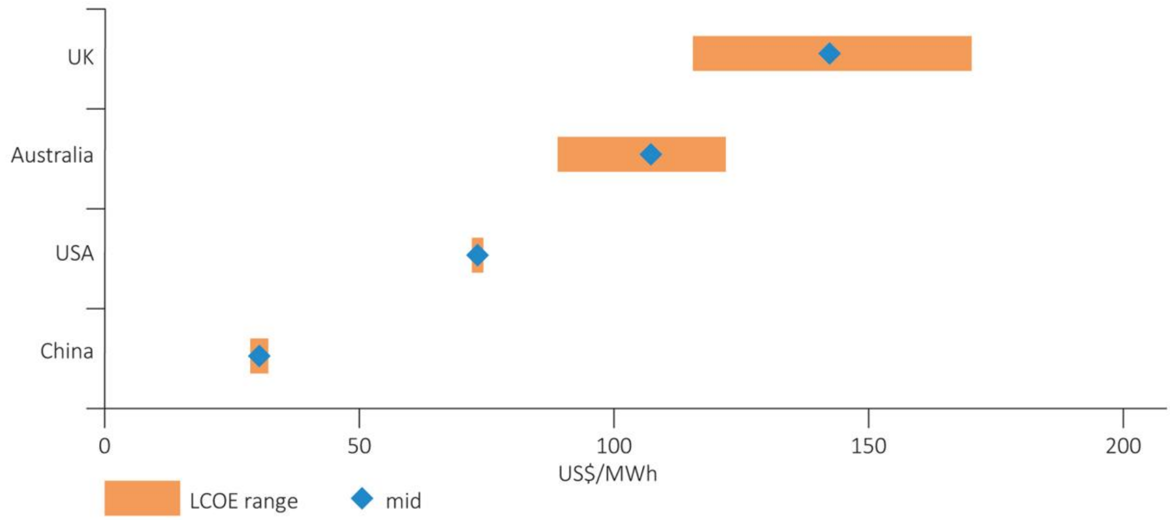


Figure 24 The LCOE for coal-fired energy by country, US$/MWh (WEC, 2013)

The LCOE (also known as, all-in costs) and their composition as a function of dependence of full load hours are illustrated by Schröder and others (2013) (*see* Figure 25). A 9% discount rate is assumed at 2010 fuel prices (IEA 2011b) and a CO_2 price of 20 €/t. European Energy Exchange (EEX) prices assist in identifying the range at which power plants would be profitable. Even at high use/load factors, power plants generate little profits from 'energy-only markets' under 2010 EEX prices. Nuclear power was found not to be competitive in any case, with all-in-costs of around 100 €/MWh at 8000 full load operating hours, not including insurance costs.

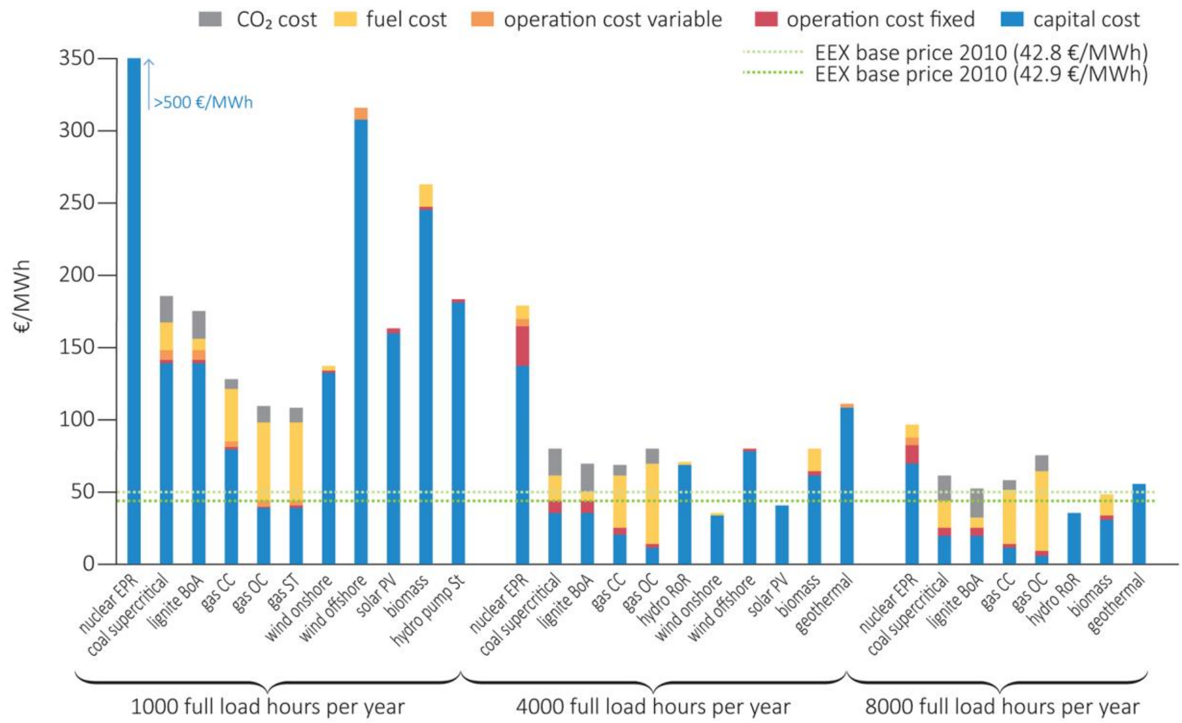


Figure 25 2010 levelised (LCOE) costs of various generation technologies, €/MWh (Schröder and others, 2013)

More recently, VGB (2015) published a report on the levelised cost of electricity including a discussion on the limitations of LCOE calculations in deregulated markets with the focus on Europe. According to VGB (2015), LCOE relates to the costs of a technology up to connection to the grid. By definition, these costs do not consider any effects at the technology level, in that, specific technologies demand additional investment in transmission and distribution grids or specific additional reconfigurations of the electricity systems, such as flexibility or added capacity provision. VGB (2015) consider the estimation of each technology costs a complex undertaking, and acknowledge that no common methodology is applied and accepted internationally. The results obtained in one undertaking cannot be applied generally to a different context nor can the analysis be extrapolated to different penetration levels. Any undertaking to do so would need additional analysis to guarantee robust results. LCOE results are influenced by the definition of system costs, the definition of boundaries between categories, the time horizon (short term compared to long term) and assumptions about the ability of the power system to adapt, and about future parameters, including fuel and CO_2 prices.

The LCOE calculations in the VGB (2015) report were made under the premise of creating a best (minimum) and worst (maximum) case optimum of LCOE. Minimum and maximum cost components used as input values were the investment cost, discount rate, plant lifetime, O&M, fuel cost, carbon price, electrical efficiency, carbon factor and full load operation. The input values for minimum LCOE were minimum investment cost, minimum discount rate, lifetime, minimum O&M, minimum fuel cost, minimum carbon price, maximum electrical efficiency, carbon factor and maximum full load hours. The input values for maximum LCOE were maximum investment cost, maximum discount rate, lifetime, maximum O&M, maximum fuel cost, maximum carbon price, minimum electrical efficiency, carbon factor and minimum full load hours. The methodology used by VGB (2015) to calculate the LCOE assumes a baseload market, but this is the case only for some hard coal, lignite and gas CCGT power plants in Europe. As such, the approach was modified for hard coal, lignite and gas CCGT power plants and two scenarios introduced. The real case reflects the current operation hours in the electricity market and the ideal case, which focuses on the general optimum range (*see* Figure 26 and 27, respectively).

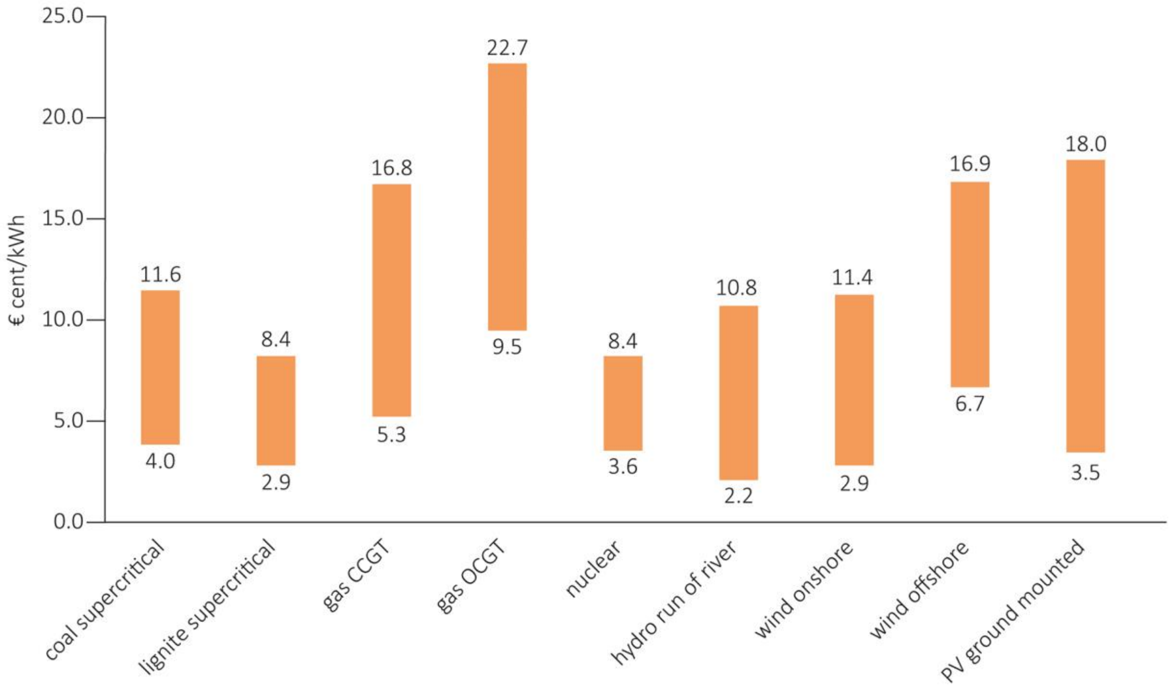


Figure 26 Levelised cost of electricity for different technologies (real case scenario) (VGB, 2015)

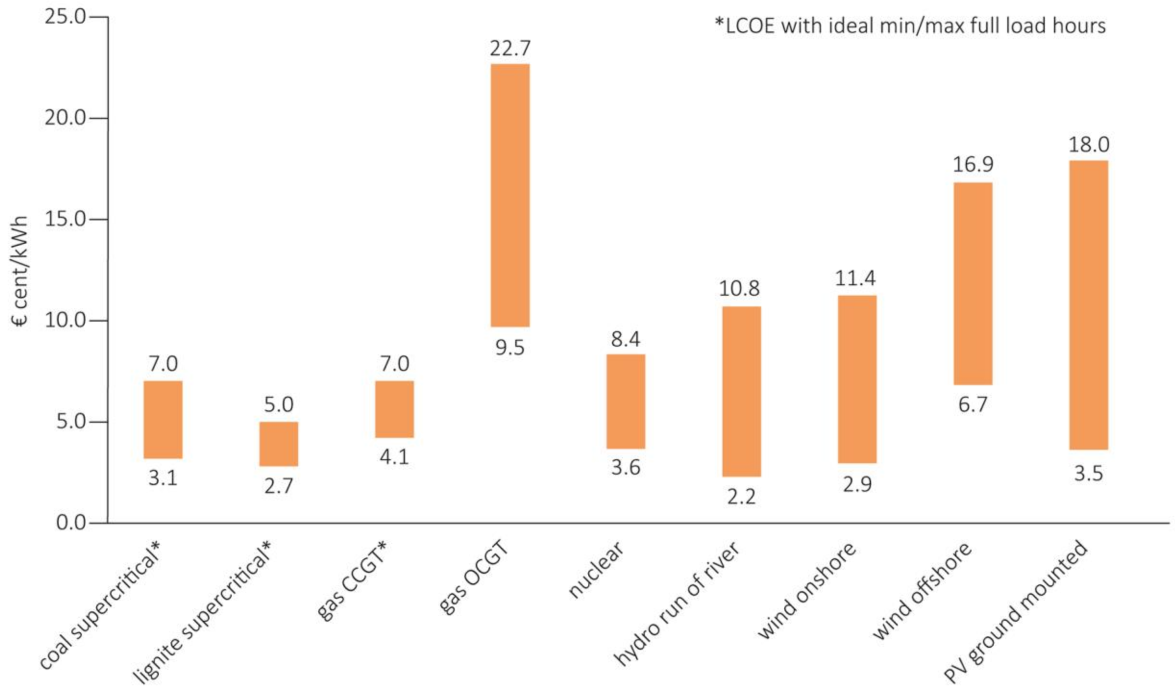


Figure 27 Levelised cost of electricity for different technologies (ideal case scenario) (VGB, 2015)

VGB (2015) consider that, in liberalised electricity markets, which has been introduced in many OECD countries since the 1990s, the LCOE methodology is not particularly well-suited to assess the competitiveness of different generation technologies. That is because competitive electricity markets establish prices that reflect the marginal costs rather than average costs that underlie LCOE accounting, independent of system issues.

In its 2015 report on the projected costs of generating electricity, the IEA presented the results of research performed in 2014 and early 2015 to calculate the cost of generating electricity for both baseload electricity generated from fossil-fuelled thermal as well as nuclear power stations and a range of renewable generation including wind and solar. The study forecast the expected cost of commissioning these plants in 2020. The LCOE calculations were based on a levelised average lifetime cost approach, using the discounted cash flow (DCF) method. The calculations used a combination of generic, country-specific and technology-specific assumptions for the various technical and economic parameters. The analysis was performed using three discount rates (3%, 7% and 10%). Costs were calculated at the plant level (busbar), and therefore did not include transmission and distribution costs. Similarly, the LCOE calculations did not capture other systemic costs or externalities beyond CO_2 emissions. The analysis was based on data for 181 plants in 22 countries. Figure 28 shows the range of LCOE results for the three baseload technologies analysed in the report (natural gas-fired CCGTs, coal and nuclear). At a 3% discount rate, nuclear is the lowest cost option for all countries. However, consistent with the fact that nuclear technologies are capital intensive relative to natural gas or coal, the cost of nuclear rises relatively quickly as the discount rate increases. As a result, at a 7% discount rate the median value of nuclear is close to the median value for coal, and at a 10% discount rate the median value for nuclear is higher than that of CCGTs or coal. These results include a carbon cost of 30 US$/t, as well as regional variations in assumed fuel costs. The ranges presented in the figure include results from all the countries analysed in the study, and therefore contain some obscure regional variations. For a more detailed analysis, *see* IEA (2015b).

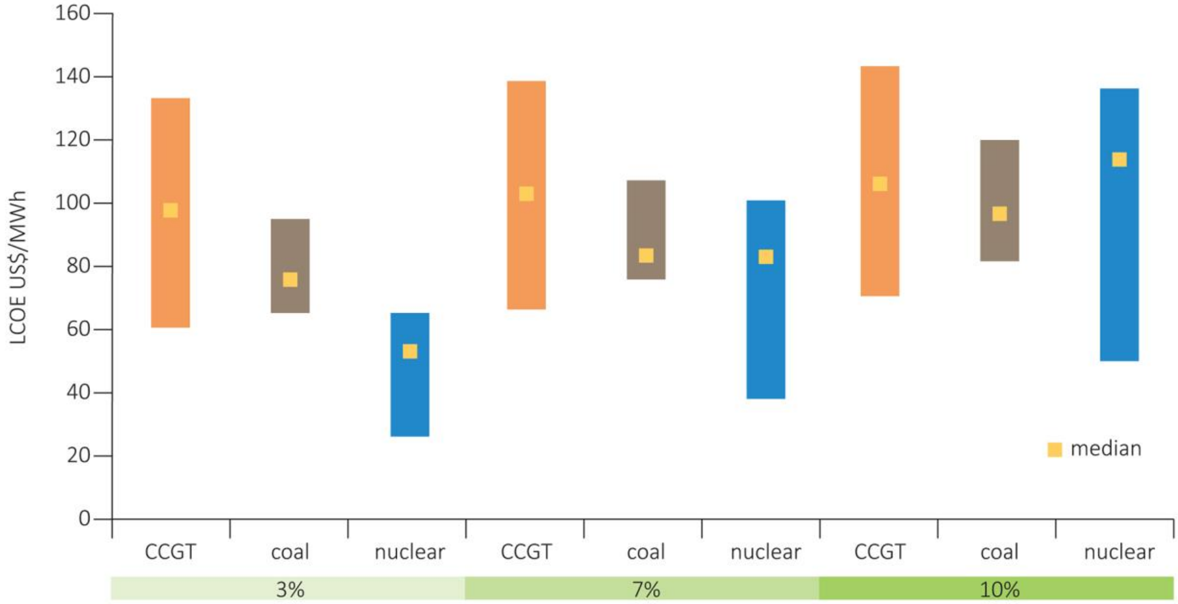


Figure 28 LCOE ranges for baseload technologies (at 3%, 7% and 10% discount rate) (IEA, 2015)

According to IEA (2015b), the estimated overnight costs for coal-fired plants in OECD countries range from a low of 1,218 US$/kWe in Korea to a high of 3,067 US$/kWe in Portugal. In OECD countries, in general, the LCOE at a 3% discount rate range from a low of 66 US$/MWh in Germany to a high of 95 US$/MWh in Japan. At a 7% discount rate, the LCOE range is from 76 US$/MWh (Germany) to 107 US$/MWh (Japan), and at a 10% discount rate the LCOE range is from 83 US$/MWh (Germany) to 119 US$/MWh (Japan). For coal-fired plants in non-OECD countries (including China), an estimated overnight cost of 813 US$/kWe is forecast and an overnight cost of 2,222 US$/kWe is estimated for South Africa. The estimated LCOE for China is 74 US$/MWh at a 3% discount rate, 78 US$/MWh at a 7% discount rate and 82 US$/MWh at a 10% discount rate. For South Africa, the estimate is higher at 65 US$/MWh at 3%, 82 US$/MWh at 7% and 100 US$/MWh at 10% discount rate. The IEA (2015b) concluded that the cost drivers for the different generating technologies were both market- and technology-specific. As such, there is no specific technology that is best value under all circumstances and that system costs, market structure, environmental policy and resource availability continue to play an important role in determining the final levelised cost of any given investment.

4.4 Cost analyses

Cochran and others (2014 and 2013) discussed strategic modifications, proactive inspections, training programmes and other various operational changes at a US coal-fired power plant to accommodate cycling and minimise the extent of cycling-related-damage maintenance costs. An anonymous coal-fired power station was the subject of the analysis. When it came online in the 1970s, the plant was intended to run at an 80% annual capacity factor. However, the addition of nuclear power displaced coal as the principal source of baseload generation. Consequently, the plant ran typically at 50% annual capacity factor until the early 1990s. Considerable research, conducted in the 1980s to understand the effects of 'two-shifting' (that is, cycling on and off in a day), resulted in modifications in plant operations, the steam generator and supporting equipment. The plant was operated for longer periods at full plant output during the 2000s, during which significant forced outages were experienced. For example, in 2004, the equivalent forced outage rate (EFOR), a measure of plant unreliability, was 32%, which represented the accumulated latent damage from the cycling performed at the plant in the 1990s. Typical EFOR for a baseload coal-fired power plant is 6.4% (Cochran and others, 2014 and 2013).

According to Cochran and others (2014), each coal-fired power generating unit experiences an average of 1760 start-ups, including 523 cold start-ups throughout its lifetime. The overarching effect of this type of cycling is thermal fatigue. For example, large temperature swings from cold feedwater entering the boiler on start-up and from steam as it is heating create fluctuating thermal stresses within single components and between different components when materials heat at different rates. Other typical effects of cycling and operating at low loads include (Cochran and others, 2014):

- stresses on components and turbine shells resulting from changing pressures;
- wear and tear on auxiliary equipment used only during cycling;
- corrosion caused by oxygen entering the system during start-up and by changes in water quality and chemistry; and
- condensation from cooling steam during ramping down and shutting down, which can cause corrosion of parts, water leakage, and an increased need for drainage.

The effects (*see* Table 13) can cause components, particularly in the boiler, to fatigue and fail leading to increased outages, increased O&M and therefore, costs, additional wear and tear from the increased O&M, necessitate the introduction of more extensive and sophisticated training, inspection, and evaluation programmes. The damage from cycling is not immediate as components may fail and EFOR may rise a few years after significant cycling.

Table 13 Issues experienced due to cycling at an unnamed coal-fired power plant (Cochran and others, 2014)

Issue	Cause/Impact
Failure of boiler tubes	Caused by cycling fatigues, corrosion fatigue and pitting.
Cracking in dissimilar metal welds, headers and valves	Due to rapid changes in steam temperature.
Cracking of generator rotors	Due to movement between the rotor and casing during 'barring' (slow turns to keep rotors from being left in one position too long during turning-gear operation).
Oxidation from exposure to air on start-up and draining	Oxides in boiler tubes may dislodge due to thermal changes and lead to damage downstream, such as the turbine blades.
Corrosion of turbine parts	From oxides, but also from wet steam that occurs on start-up, during low-load operations and during poor plant storage conditions when the plant is dried.
Condenser problems	Can occur when thin tubes crack from thermal stresses at start-up and shut-down.

Numerous physical modifications to equipment were carried out to prevent and address impacts from cycling and low-load operations. The changes focused on actions that improve drainage and thermal resiliency and reduce opportunities for corrosion, *see* Table 14. Replacement of parts or modification to components were decided and carried out case-by-case and based on wholesale power market opportunities in the following year justifying the cost of modifications to reduce the forced outage rate.

Table 14 Example modifications to operating procedures to support cycling at an unnamed coal-fired power plant in the USA (Cochran and others, 2014)

Boiler	Added a metal overlay to water walls to minimise oxidation, cut back membranes in various areas to reduce start-up stresses and replaced dissimilar metal welds.
Turbines	Added drains, upgraded the lubrication system, modified vacuum pumps and low-pressure crossover bellows and inspected the non-return valves, which can be damaged during shut-downs.
Generator rotors	Insulated and epoxied key parts to reduce rotor cracking from rubbing and established continual tests and checks to monitor trends.
Condenser	Plugged the tubes at the top of the condenser that had been damaged as a result of low-load operation and water impingement, reducing overall efficiency; also installed stainless-steel air removals and re-tubed the existing brass on several units.
Natural cooling	Accelerated forced cooling for the boiler, enabling the operator to shut down the unit quickly to repair a boiler tube and be back online in two days. However, after a year of implementing accelerated forced cooling, the units recorded a noticeable increase in corrosion and cyclic fatigue failures. As such, the shut-down procedures were modified to keep the boiler shut for the first four hours (natural cooling).
Monitoring economiser inlet headers	Economiser inlet headers can crack from intermittent additions of cold feedwater to the hot inlet header. The operator keeps the temperature difference between the header and water at less than 30°C, below the boiler manufacturer recommendation.
Pressure part management	The operator developed a pressure-part management programme, reviewing every pressure component and establishing causes for degradation and failure.
Other changes to boiler operating procedures	Included a programme to monitor boiler metal temperature; a tube inspection and replacement strategy, a thermal and cyclic fatigue inspection programme, a fly ash erosion programme to reduce tube failures and an inspection programme for expansion joints, dissimilar metal welds and flow-accelerated corrosion.
Temperature monitoring for turbine parts	The operator established training and monitoring procedures, with associated monitoring equipment, to limit ramp rates and to monitor temperature changes to thick-walled fittings, headers and the casing to the main steam line.
Water chemistry maintenance	To reduce corrosion, water chemistry must be maintained to protect surfaces that oxidise. As water chemistry varies with cycling, a chemistry-staff and a chemistry management system (following ISO standards) are maintained on site
Overall monitoring programme	An overall plant monitoring programme was developed by comparing reports on best practices associated with cycling, plant equipment status and mitigating actions.

Cochran and others (2014) consider that costs associated with cycling, and modifications made in response, are difficult to distinguish from normal operating costs. Modifications were made over the course of decades, in response to both cycling and non-cycling wear and tear, to achieve EFOR rates that varied by unit and year. Extrapolating cost implications to other coal-fired power plants generally from the experiences at a specific facility is difficult due to variations in age, design and history of operations. Also, decisions on the scope and timing of modifications depend on business case justifications, which are highly market- and context-driven and could vary with time. Early recognition of significant cycling at the plant drove the modified operating practices and equipment to minimise the impacts of cycling. Thus, Cochran and others (2014) consider that the proactive changes meant that the costs to mitigate cycling based on EFOR rates at the plant are likely to be less than those for other plants with similar cycling and EFOR rates which were not proactive in their dealing with cycling issues and problems. Cycling also incurs costs associated with increased emissions rate. An emissions control technology needs to be operated also at a minimum load. Other emissions impacts occur due to increased fuel use at start-ups, reduced plant efficiency at less than full load, and reduced effectiveness of pollution-control equipment when flue gas temperatures at start-up are too low to support the chemical reactions needed. Emissions rates during cycling can be higher than during non-cyclic operation (Cochran and others, 2013, 2014).

According to Kumar and others (2016), forced outages and equivalent derations are typically more frequent and of longer duration in cycling baseload units that are not designed for cycling compared to units designed for cycling (*see* Figure 29).

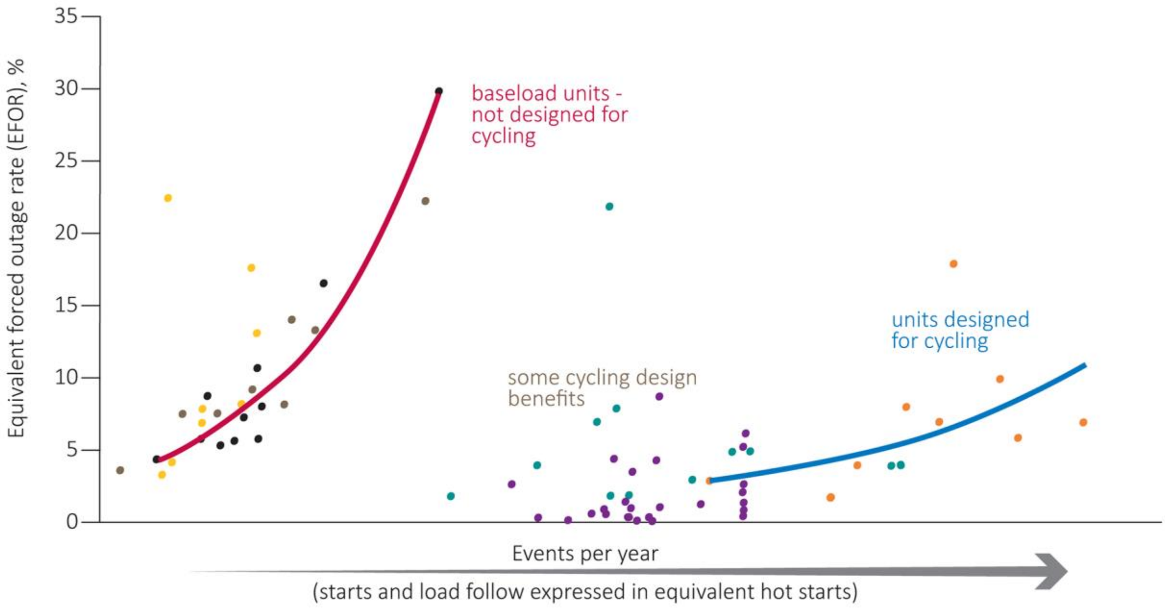


Figure 29 Risk chart of forced outage rates and plant cycling in coal-fired units (Kumar and others, 2016)
Note that each symbol in the figure represents a different coal-fired unit. Units not designed for cycling tend to have higher annual forced outage rates with fewer accumulated starts compared to units that are designed for cycling

The recovery costs for additional forced outages should include some of the outages due to operator error. Such errors have included boiler explosions, boiler implosions, generator out-of-phase synchronisation, generator motoring, water induction damage, miscellaneous operator valving errors, miscellaneous human errors, and automatic equipment and control system failures. Kumar and others (2016) consider that increased cycling results in increased opportunities for error. Often forced outages, result in the cost of having to increase utilisation of less economical generation units (or purchase power) due to lower availability of the cycled units. Typically, utilities make cycling decisions based on factors including unit size, age, equipment type, fuel costs, system requirements, production costs and more. Power plant cycling costs vary greatly and depend on several factors such as, design, vintage, age, and plant O&M history. When the system requirements necessitate cycling, a key decision for operators is to determine how to mitigate the effects of cycling. Tables 15 and 16 present Kumar and others' (2016) summaries of the effects of cycling on plant components and plant cycling risk reduction or mitigation measures.

Table 15 Effects of cycling on plant components (Kumar and others, 2017)

Boiler	Turbine	Chemistry	Electrical
• Fatigue cracking of - boiler tubes in furnace corners - tube to buckstay/tension bar - tube to windbox attachment - tube header - tube to burner - membrane to tube economiser inlet header - header ligament • Boiler seals degradation • Tube rubbing • Boiler hot spots • Drum humping/bowing • Downcomer to furnace sub-cooling • Expansion joint failures • Superheater/reheater tube leg flexibility failures • Superheater/reheater dissimilar metal weld failures • Start-up related tube failures in waterwall, superheater and reheater tubing • Burner refractory failure leading to flame impingement and short-term tube overheating	• Cracking due to water induction into turbine • Increased thermal fatigue due to steam temperature mismatch • Steam chest fatigue cracking • Steam chest distortion • Bolting fatigue, distortion/cracking • Blade nozzle block, solid particle erosion • Rotor stress increase • Seals/packing wear/destruction • Blade attachment fatigue • Disk bore and blade fatigue/cracking • Silica and copper deposits • Lube oil/control oil contamination • Shell/case cracking • Wilson line movement • Bearing damage	• Corrosion fatigue • Oxygen pitting • Corrosion transport to boiler and condenser • Air, carbon dioxide, oxygen in-leakage • Ammonia, oxygen attack on admiralty brass • Grooving of condenser/feedwater heater tubes at support plates • Increased need for chemical cleaning • Phosphate hideout leading to acid and caustic attack • Silica, iron and copper deposits • Out of service corrosion	• Increased controls wear and tear • Increased hysteresis effects that lead to excessive pressure, temperature and flow • Controls not responsible • Motor control fatigue • Motor insulation failure due to moisture accumulation • Motor mechanical fatigue due to increased starts/stops • Wiring fatigue • Insulation fatigue degradation • Increased hydrogen leakage in generator • Fatigue of generator leads • Generator retaining ring failures • Generator end turn fatigue and arching • Bus corrosion when cool (that is, low Amps) • Breaker and transformer fatigue

Table 16 Plant cycling risk mitigation measures (Kumar and others, 2016)

Utility operation area	Risk reduction measure
Plant operation	• Modify start-up, shut-down, turndown and ramping protocols to lower component fatigue stresses. For example, determine whether force cooling boiler is for economic reasons or simply to accommodate maintenance staff. • Monitor and inspect closely. Modify inspection plans around cyclic operation. • Train operators on best practices. Use operator alarms to reduce thermal stresses. • Follow appropriate cycle chemistry limits. Install condensate polishing system for rapid water chemistry • Use nitrogen blanketing of condensate storage tank, boiler, turbine.
Plant maintenance	• Establish formal reliability, availability and maintainability (RAM) programme • Do predictive maintenance accounting for cycling damage, to minimise cycling related forced outages • Install thermocouples in strategic locations (for example, drains) to monitor condensate accumulation • Risk-rank equipment vulnerable to cycling
System dispatch	• Include both short-term and long-term cost of cycling in system dispatch. On a new plant, short-term maintenance costs might be small but it is important to develop and plan a long-term maintenance plan to mitigate future intermittent cost shocks • Determine whether saving fuel cost in the short run while jeopardising the integrity of the asset in the future is a worthwhile risk?
Contracts	• Include cycling costs in the negotiations and accounting of energy and capacity transactions • Determine the impact of the transaction on total system cycling costs
System planning	• Benchmark the operating profile with peer group of units • Account for cycling costs on existing units when evaluating new resources
New construction	• Design and procure designs better suited to cycling. Initial capital investment in an auxiliary boiler or larger condensate storage tanks should be considered • Use prior/past experience and industry best practices to build flexible assets

In summary, the incremental increases in costs attributed to cycling include increases in maintenance expenditure, forced outage effects (including lost time and energy capacity), increased unit heat rate and impacts on long-term efficiency (especially efficiency at low/variable loads), the cost of start-up fuels, auxiliary power, chemicals and additional operational staffing requirements for unit start-ups, and reducing the long-term generation capacity of the unit if and when cycling results in reducing the lifetime of the unit (Kumar and others, 2016).

In their report on the development of the global and European electricity demand, Christensen and others (2015) considered that electricity generation costs will double if a power plant unit that is designed for baseload with about 6,000 estimated full load hours is operated for ~2,000 hours. If the plant operating hours are cut further by 1,000 hours, generation costs will increase by a factor of 4 (*see* Figure 30). This has particularly negative impacts on highly efficient new power plant sites, because these are burdened by a high share of fixed costs mainly made up of capital costs, staff and maintenance costs. New thermal power plants face additional economic risks when using fuels that are subject to large price fluctuations. According to Christensen and others (2015), the market mechanisms of the European energy market need to be reshaped in order to realise new power plant projects, that is disposable back-up capacity to secure reliable electricity supply.

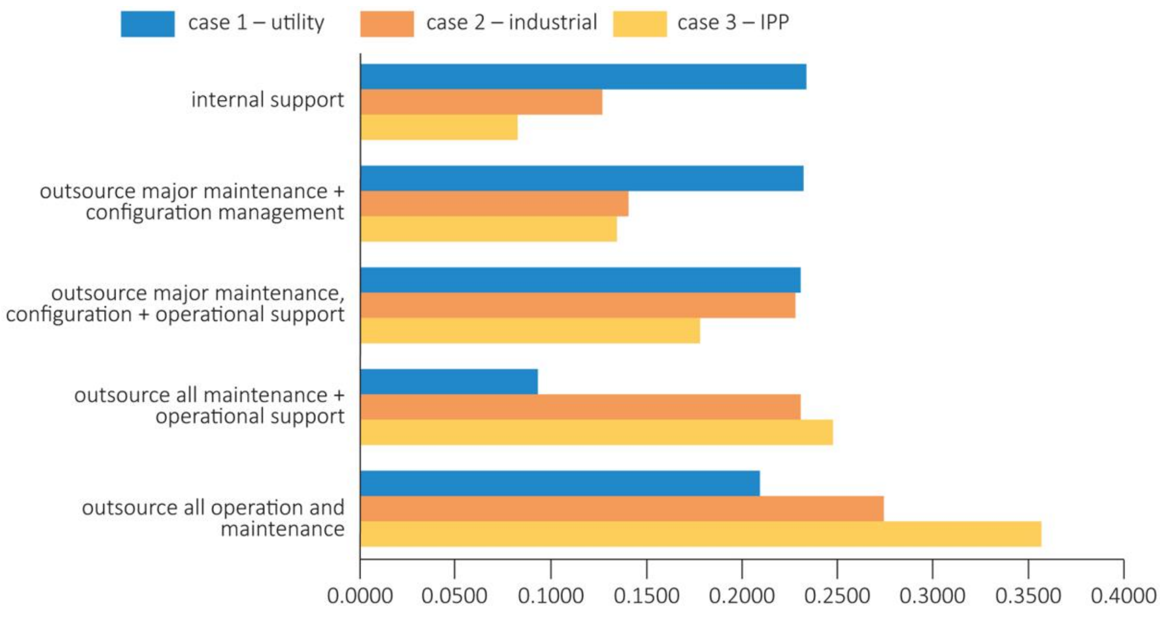


Figure 30 Cost of electricity (CoE) production (Christensen and others, 2015)

Christensen and others (2015) consider that increased utilisation of renewable energy can only be realised when supported by thermal power plants in order to continuously balance power generation and consumption. Existing power plants provide important services including back-up capacity that is available at any time, primary and secondary control, minute reserve and reactive power and re-dispatch and black start capacity. Black Start is the procedure to recover from a total or partial shut-down of the transmission system which has caused an extensive loss of supplies. This entails isolated power stations being started individually and gradually being reconnected to each other in order to form an interconnected system again.

Incremental costs, that is, the increase in total costs resulting from higher costs beyond fixed costs when a power plant generates electricity, determine pricing and utilisation of different power plant types at the energy market. Figure 31 shows the incremental costs for hard coal and gas-fired power plants in relation to the medium revenues at the electricity wholesale market. Assuming that the average fuel prices in 2013 amounted to 9 €/GJ for gas and 2.7 €/GJ for coal, the figure shows that current revenues at the electricity wholesale market are not sufficient to cover the incremental costs of the power plants. Hard coal-fired power plants can only cover their incremental costs if the plants are operated annually for more than ~4,500 full load hours, as at low utilisation rates the incremental costs are much higher. In the long term, revenues in the amount of incremental costs are not profitable, since debt service is then impossible, that is, in the long run power plant operation has to strive to cover full costs and to achieve a return on investment (Christensen and others, 2015).

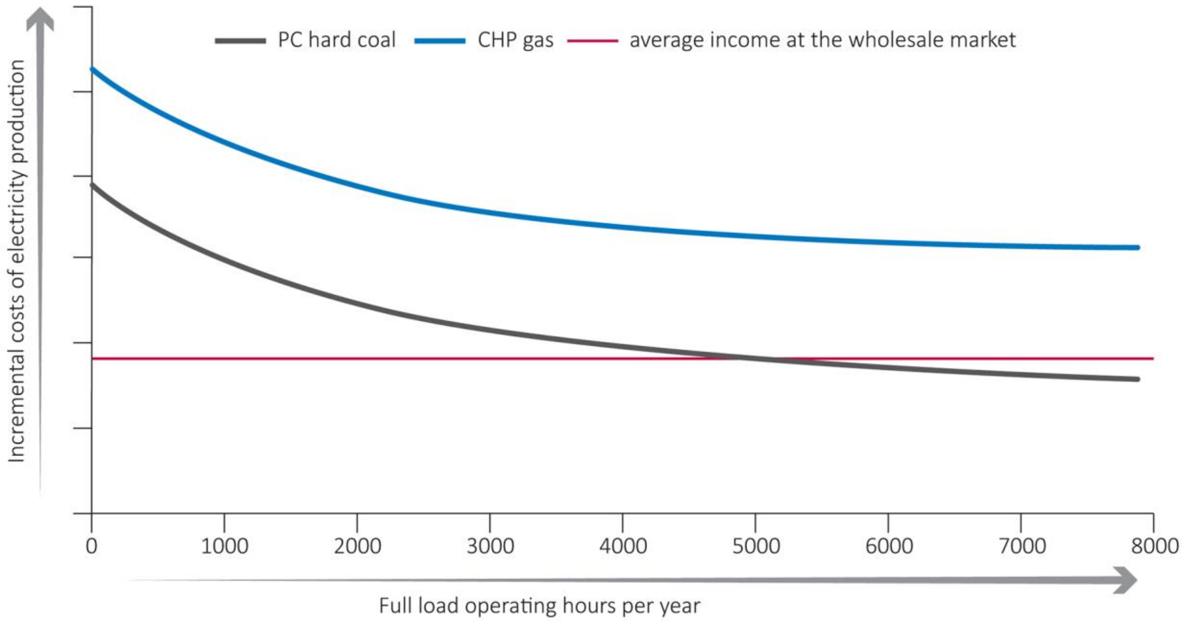


Figure 31 Incremental costs of electricity production in the wholesale market (Christensen and others, 2015)

According to Christensen and others (2015), in order to deal with issues resulting from cycling coal and gas-fired plants, to meet demand when renewables cannot, new power plants in Germany are designed for particularly flexible operation, independent of the type of fuel used, hard coal, lignite or natural gas. A comparison of the flexibility of a state-of-the-art CCGT and lignite-fired power plants is shown in Figure 32.

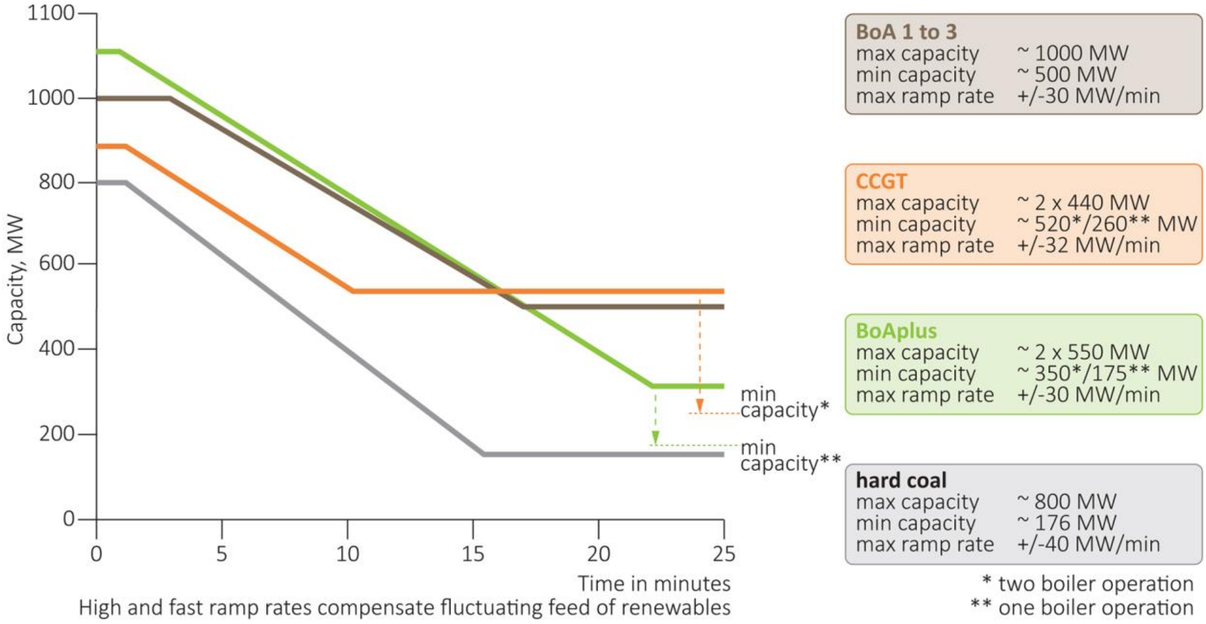


Figure 32 Flexibility comparison of a state-of-the-art CCGT and lignite-fired power plants (Christensen and others (2015)

The main engineering criteria considered for flexibility are stable minimum load, start-up and shut-down times as well as minimum operation and downtimes, load gradients and control range at different loads. New and retrofitted old coal- and gas-fired power plants can contribute to the integration of renewables into the European electricity supply grid due to their short-term flexible operation and thus have a role in future energy supply. Against the background of the renewables targets in Europe, a flexible thermal power plant fleet will remain inevitable in order to guarantee economic efficiency and supply security at all times (Christensen and others, 2015).

4.4.1 Carbon capture and storage (CCS) cost

Established CO_2 capture technologies are associated with significant energetic and economic penalties, reducing power plant efficiency by around 10% points and increasing the cost of electricity production by up to 80%. Partly as a consequence of these limitations, deployment of large-scale CCS on coal power plants has been limited, and remains largely confined to regions with a particularly favourable economic and legislative environment. Dedicated research programmes worldwide have therefore pursued the development of a wide range of innovative, alternative technologies for CO_2 capture (Lockwood, 2016). Visit www.iea-coal.org for detailed reviews on GHG control technologies and CCS developments and status.

At the beginning of 2010, there was an expectation that by 2014/15, up to 12 large-scale CCS plants would be in operation in Europe alone. However, to date there are only two large-scale CCS plants operating in Europe (both in Norway), and 13 operational facilities in the world, the majority of which are associated with enhanced oil recovery (EOR) operations, that is, carbon capture, utilisation and storage (CCUS). This is mainly because CCS is not commercially viable yet due to high cost (both in monetary and power consumption terms), and remains mostly in the demonstration stage (Nalbandian-Sugden, 2015).

In 2009, the IEA produced its technology roadmap for CCS as part of modelling a pathway to meet the 2°C target (IEA, 2009). The roadmap projected 100 large-scale CCS projects to be in operation by 2020. In 2013, the roadmap revised that number to thirty (IEA, 2013). The projects included CCS for both power and industrial sectors, as well as for coal and other fuels. The utilisation of thirty large-scale projects is equivalent to the capture and storage of approximately 50 Mt of CO_2 (IEA, 2009 and IEA, 2013). Banks and others (2015) note that there are several key factors emerging in making CCS work from an economic perspective. These include the use of cheap, stranded coal, a plant working at full load and a strong business case, for example, carbon capture and use in EOR (CCUS). However, these factors are localised and not present everywhere. Banks and others (2015) quote the IEA costing of CCS as 90% carbon capture increases capital costs between 45% and 75% and reduces plant efficiency by 20–25%. Without a strong and driving policy, in particular, the adoption of a carbon price, and where natural gas is competitive with coal, such as in the USA, CCS will remain an uncompetitive option. Nevertheless, Krutka and others (2015), who discussed pathways for CO_2 utilisation (not discussed in this review), consider that due to the increasing global population and expanding energy access, total world energy consumption is projected to grow by 56% by 2040, with fossil-fuels providing nearly 80% of demand. The effect of these trends on future CO_2 emissions and how to mitigate their potential impacts not only requires but necessitates the utilisation of *commercially available and cost competitive CCS technology* in order to enable emerging economies to have access to proven, available and reliable energy supplies.

Schröder and others (2013) discussed the capture, transport and storage costs of CCS technologies. However, the authors considered that it was impossible to obtain a coherent set of cost data, since there was no full-scale, commercial operation of an existing carbon capture, transport and permanent storage (CCTS) application. Nevertheless, Schröder and others (2013) compared the existing estimates and presented the following outlook for CCTS. The availability of CCTS technology is primarily determined by technological progress. Progress in improving the technologies depends on the future of fuel and CO_2 prices, GHG policies and renewable energy sources. Analysis indicates that CO_2 emission pricing needs to reach 30 US$/t$CO_2$ in order for plants equipped with carbon capture technology to be competitive with coal-fired power plants without a carbon capture system. Calculations suggest that CCTS cannot be profitable at carbon prices below 70 €/t CO_2 and favourable conditions regarding fuel prices and full load operation. In 2012, when prices were lower than 10 €/t CO_2, CCTS could not be considered competitive at the then current state of technology development. On 10 August 2016, the price was 4.8 €/tCO_2, far below the 30 €/tCO_2 analysts consider the minimum price required for driving emissions reductions and low carbon investment (EEX, 2016). Estimates for CCTS market deployment, at least as a retrofit technology, range from an optimistic 2020 to as late as 2070. Given the current state of the technologies and numerous analyses, 2030 is considered by Schröder and others (2013) as a realistic timeframe for wide-scale commercial application of CCTS technologies.

CCTS technology is currently in the development stage; further improvements concerning both investment costs and efficiency could be expected. The use of quantitative modelling of cost reductions and project learning curves for CCTS implementation were also considered by Schröder and others (2013). This was done by estimating learning curves of other emission control technologies already in operation, for example, flue gas desulphurisation (FGD) technology which is used widely in coal-fired power plants to control SO_2 emissions. The estimates show that the resulting learning rates are similar to those for other emission control technologies, for example, selective catalytic reduction (SCR) systems used to control NOx emissions. As such, analysts assume that FGD and SCR technology learning rates may be used for estimating future development of CCTS costs. Based on this assumption, investment costs for CCTS are predicted to decline by 13% for every doubling of capacity. This is in line with goals for investment cost reduction of 10-12% every 10 years until 2030 set in the IEA (2009) "*technology road map carbon capture and storage"*

The Australian Energy Market Operators (AEMO) planning functions rely on an underlying set of input assumptions that characterise the behaviour of existing generation assets, and the economics/location of future investment and retirement decisions. The dataset includes projections of fuel and technology costs for both existing and emerging generation technologies. The dataset also encompasses the technical operating parameters of these units. For emerging technologies, the dataset specifies location incentives/limits, construction lead-times, and earliest commercial viability dates. The data is used by AEMO to conduct market simulation studies for medium- and long-term planning purposes, in particular, the analysis underlying the annual National Transmission Network Development Plan (NTNDP). ACIL Allen Consulting (ACIL Allen, 2014) were engaged by AEMO to undertake an update of the technology costs, fuel costs and technical parameters contained within the NTNDP assumptions database (ACIL Allen, 2014).

According to ACIL Allen (2014), coal-fired power continues to be the baseload generation technology within the National Electricity Market (NEM) (Australia). New coal-fired generation is likely to be supercritical and utilise CCS as the technology matures, is widely demonstrated at utility scale, and proven to be economical. Four coal based technology options were reviewed against AEMO's current new plant planning data including: supercritical pulverised black coal with CCS, supercritical pulverised black coal without CCS, supercritical pulverised brown coal with CCS and supercritical pulverised brown coal without CCS. Pulverised coal-fired power plant design was based on a conventional boiler with single reheat supercritical steam turbine generator, wet natural draft cooling tower and air quality control equipment (particulate control). Cases were modelled with and without CCS technology installed. The steam generator was assumed to include low NOx burners and the plant to have a total generated (gross) capacity of 750 MW. Thermoflow software version 23 was used to model and derive the performance parameters of the pulverised coal and CCS technologies, including capital costs. Thermoflow software utilises several cost factors which may be adjusted from defaults for a more accurate representation of costs in different countries or regions. These cost factors are provided in Table 17. The cost factor for specialised equipment (for example, boilers, steam turbines, and feedwater heaters) and labour were altered from the Thermoflow software default settings to reflect the changing attitude of the Australian market to source power generation equipment from Asian countries such as China and India and to reflect Australia's high labour rates.

Table 17 Thermoflow software cost factors for coal (ACIL Allen, 2014)			
Cost factor	**Thermoflow default (Australia)**	**Adjusted factor**	**Comment**
Specialised equipment	1.3	1.0	Adjusted for Asian sourced equipment
Other equipment	1.3	1.3	No change
Commodities	1.3	1.3	No change
Labour	2.025	3.0	Adjusted for high domestic labour rates

ACIL Allen (2014) consider that supercritical pulverised coal technology is mature and therefore not expected to experience dramatic cost or efficiency improvements in the future. However, CCS technology is considered likely to experience both cost and efficiency improvements (through a reduction of auxiliary loads) as the number of installed units increases throughout the world. Tables 18 and 19 give the potential cost values of black/hard/bituminous coal and brown/lignite/sub-bituminous coal, new, pulverised-coal power plants with CCS and without CCS.

Table 18 Costs and details of new bituminous, supercritical, pulverised coal power plant with and without carbon capture and storage (CCS) (ACIL Allen, 2014)		
Technology description	**Supercritical (with CCS)**	**Supercritical (without CCS)**
Capital cost, A$/kW sent out (net capacity)	5,388	2,880
Local equipment/construction costs (includes commodities), %	36	31
International equipment costs, %	35	39
Labour costs, %	29	30
Construction profile % of capital cost	Year 1 – 35 Year 2 – 35 Year 3 – 20 Year 4 – 10	Year 1 – 35 Year 2 – 35 Year 3 – 20 Year 4 – 10
First year assumed commercially viable	2024	2014
Typical new entrant size (generated MW)	750	750
Economic life (Years)	50	50
Lead time for development (years)	8	6
Minimum stable generation level (% capacity)	40	40
Thermal efficiency (sent out/net capacity – HHV, GJ/MWh)	31.24	41.5
Auxiliary load, %	18.5	7.1
Fixed operating costs (FOM) (A$/MW/year) for 2014	73,200	50,500
Variable operating costs (VOM) (A$/MWh sent out/net capacity) for 2014	9.0	4.0
Percentage of CO_2 emissions captured, %	90	0
Emissions rate per kg CO_2eq/MWh (generated)	85	743

Table 19 Costs and details of new brown (Latrobe Valley), supercritical, pulverised coal power plant with and without carbon capture and storage (ACIL Allen, 2014)		
Technology description	**Supercritical (with CCS)**	**Supercritical (without CCS)**
Capital cost, A$/kW sent out (net capacity)	8,277	4,386
Local equipment/construction costs (includes commodities), %	36	34
International equipment costs, %	35	38
Labour costs, %	29	29
Construction profile % of capital cost	Year 1 – 35 Year 2 – 35 Year 3 – 20 Year 4 – 10	Year 1 – 35 Year 2 – 35 Year 3 – 20 Year 4 – 10
First year assumed commercially viable	2024	2014
Typical new entrant size (generated MW)	750	750
Economic life (Years)	50	50
Lead time for development (years)	8	6
Minimum stable generation level (% capacity)	40	40
Thermal efficiency (sent out/net capacity – HHV, GJ/MWh)	20.8	28.9
Auxiliary load, %	24.3	9.6
Fixed operating costs (FOM) (A$/MW/year) for 2014	96,500	65,500
Variable operating costs (VOM) (A$/MWh sent out/net capacity) for 2014	11.0	5.0
Percentage of CO_2 emissions captured, %	90	0
Emissions rate per kg CO_2eq/MWh (generated)	87	1126

In order to review the different technologies, a generic set of conditions was assumed to establish base case cost and performance estimates. These cost and performance estimates may vary significantly depending on the size and location of the proposed installation for a particular technology and fuel. For details on the study scenarios and assumptions *see* ACIL Allen (2014).

The Energy Technologies Institute (ETI, 2016) published an in-depth review on reducing the cost of CCS and developments in capture plant technology. The evaluation of the capture technologies was based on process, economic and system level modelling. The ETI expects that in the early years of CCS costs will reduce quickly due to economies of scale, sharing infrastructure and risk reduction. However, according to ETI (2016), SaskPower (Canada) consider a subsequent capture plant following the first demonstration plant currently in operation will be 30% less costly. The cost reduction will include savings from lower research costs and although incremental improvements to the demonstrated plant is to be expected, the greater technology improvements will not have the same impact on costs compared to actual deployment. Combined with the low uptake of CCS and the absence of a commercially ready system mean amines and pre-combustion technologies will continue to be the technology of choice in power production for several years. Key demonstration projects, which are either complete or ongoing, may cause a temporary technology lock-in, as the financial markets will be reluctant to invest in unproven capture technology because CCS projects are already perceived as high risk. ETI (2016) considers that after 2030 innovation should play an increasing role in cost reduction. However, technologies offering breakthrough performance should be funded through to demonstration level so they can enter the market when other aspects of risk have been reduced. By the mid-2030s CCS plants may have to become flexible in order to respond to daily demand changes, and therefore operate at lower load. Technologies which reduce capital costs may then be more attractive than energy saving initiatives. In the ETI system modelling, new investments for the market will favour gas turbines due to cost and biomass gasification due to the lower emissions (ETI, 2016).

5 What next for coal-fired power generation?

The discovery and harnessing of electricity changed life dramatically, especially in the developed countries, where it has enhanced lifestyle including health, transportation, employment and leisure. Today, electricity is not only essential but indispensable to our way of life. To quote Jeremy Rifkin: "*without electricity, virtually everything in modern society shuts down; the water systems, gas pipelines, sewage, transport, heat, and light. Millions would die from lack of food, water, and other basic services*." For a sense of scale, EPRI (2012) illustrated in a graphical form (*see* Figure 33) how many power plants of a given type would be required to generate the same amount of electricity. One nuclear plant or two coal-fired power generating facilities, for example (depending on size of course) can produce enough electricity to meet the annual needs of as many as a million households. However, in actual practice, a number of power generation options together and across regions are used to provide electricity, reliably (EPRI, 2012).

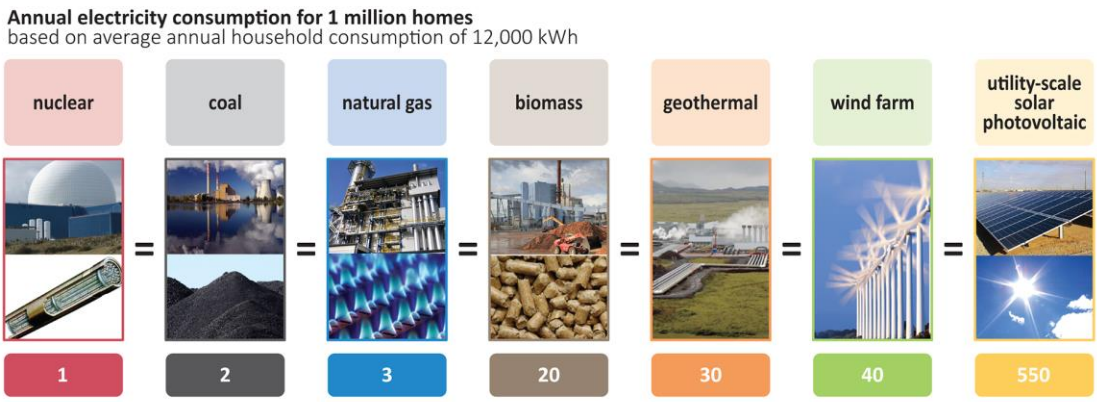


Figure 33 Annual electricity consumption for 1 million homes (based on average annual household consumption of 12,000 kWh) (EPRI, 2012)

Approximately a quarter of the current global population of ~7.2 billion do not have access to electricity. As such, electricity consumption is forecast to grow faster than any other form of energy consumption. Energy demand is expected to grow at an average rate of 2.1% every year over the period 2014-2040. It is also forecast that worldwide gross electricity consumption will increase to 36,637 billion kWh compared to the 2012 – 34,887 billion kWh. Estimates indicate that fossil fuels will continue to cover most of the demand as they will account for ~30–60% of electricity generated worldwide in 2040. Renewable energy sources will play a growing role in the global primary energy consumption structure (Christensen and others, 2015).

In the United Nations Environment Programme (UNEP) 2015 climate change conference (COP21), 195 nations around the globe met and committed to reduce their GHGs through Intended Nationally Determined Contributions (INDCs). The post-COP21 agenda focus is on the implementation of these INDCs through the 'so-called energy transition', which consists of moving away from using fossil fuels (petroleum products, natural gas, and coal) and toward cleaner energies to power the global economy (IMF, 2016; Nalbandian-Sugden, 2015).

According to BP (2015), global coal consumption grew by 0.4% in 2014 but this was well below the 10-year annual average growth of 2.9%. Energy price developments in 2014 were generally weak, with coal prices falling globally. Coal's share of global primary energy consumption was 30%. Consumption outside the OECD countries grew by 1.1%, the weakest growth since 1998, driven by reduced Chinese consumption (+0.1%). However, India (+11.1%) experienced its (and the world's) largest increase. OECD countries consumption fell by 1.5%, led by a 6.5% decline in the EU (for example, the UK (-20.3%)). However, according to the IMF (2016), as the relative price of coal to natural gas in Europe declined in recent years, the share of coal in electricity generation increased in Germany, from 43.1% in 2010 to 46.3% in 2013. Over the same time period, the share of natural gas fell from 14.3% to 10.9%. Meanwhile, BP (2016) data indicates that coal consumption recorded the largest percentage decline on record in 2015 (-1.8%) and coal prices around the world fell for the fourth consecutive year. All of the net decline was attributed to the USA (-12.7%) and China (-1.5%). The decline was partially offset by increases in India (+4.8%) and Indonesia (+15%). Coal's share in global primary energy consumption fell to 29.2%, in 2015, the lowest share since 2005 (BP, 2016). In a discussion on market trends, smart technologies, new fuels, future business models and growth opportunities, Frost and Sullivan (2014) forecast the global installed capacity in 2012, 2020 and 2030 (*see* Figure 34). Based on the forecasts shown in Figure 34, coal will continue to have the largest share in energy production in 2030 although the shares of both coal and gas will decline in the global fuel mix, while the share of renewables will rise to >40% in 2030. The changes in the global fuel mix will be driven by mainly environmental pressures, especially climate change, and more flexible generating systems (Frost and Sullivan, 2014).

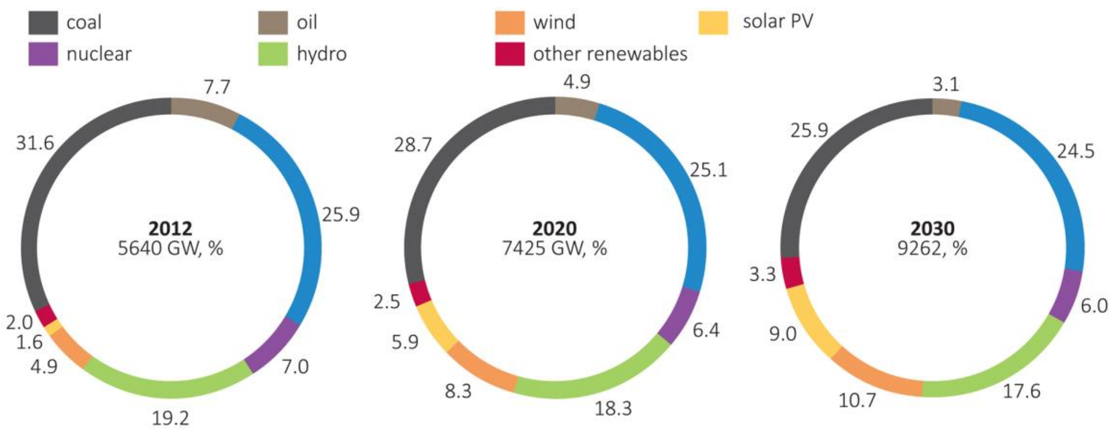


Figure 34 Global installed, existing and forecast capacity, by fuel, 2012, 2020 and 2030 (Frost and Sullivan, 2014)

According to Shearer and others (2016), global coal consumption declined in 2014 and more so in 2015. In power generation and between 2010 and 2015, coal-fired power plants were constructed in 33 countries. However, only eight of these countries added a capacity exceeding 2 GW. These were China (~298 GW), India (~101 GW), USA (~17 GW), Indonesia (~12 GW), Germany (~10 GW), Vietnam (~8 GW), Turkey (~5 GW) and Chile (~2.1 GW). China and India accounted for

85% of all new coal-fired capacity. Figure 35 illustrates the regional distribution of new coal-fired power capacity between 2010 and 2015 showing that over 90% has been in Asia. For plants currently under construction and planned for the future, Shearer and others (2016) found that the trend continues in that more coal-fired power generation facilities are planned in Asia than any other region of the world (*see* Figures 36).

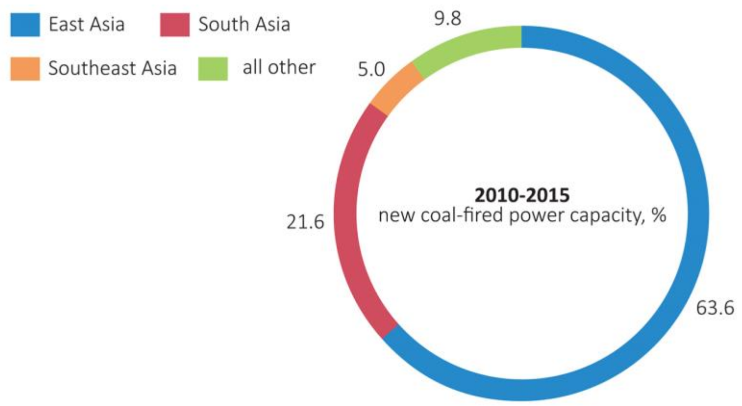


Figure 35 Regional distribution of new coal-fired power capacity, 2010-2015 (Shearer and others, 2016)

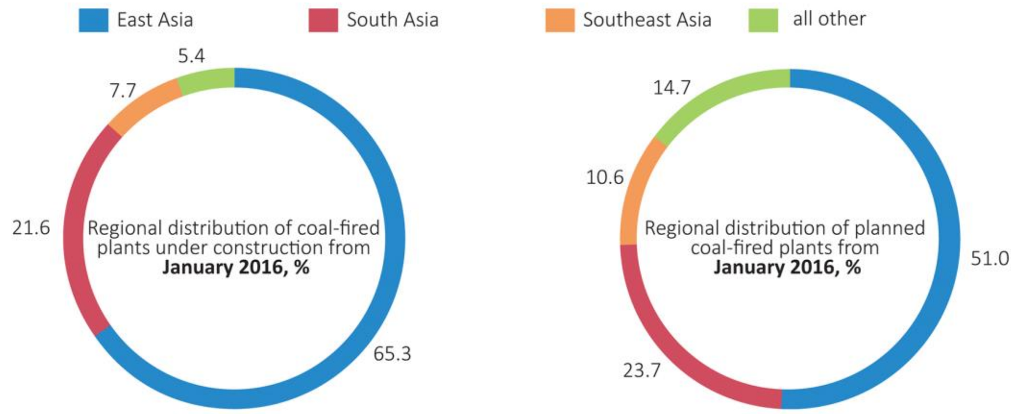


Figure 36 Regional distribution of coal-fired plants under construction (left) and planned (right) from January 2016 (Shearer and others, 2016)

Shearer and others (2016) gave the following overview of regions with regard to coal power generation:

- **East Asia**: coal-fired power generating capacity in China increased by 51.86 GW in 2015, compared with 34.22 GW in 2014. Currently 203 GW are under construction and 509 GW in the pre-construction pipeline. Japan, South Korea and Taiwan continue to be large consumers of coal and developers of new coal-fired capacity. In 2014, Japan and South Korea ranked sixth and seventh, respectively, in global coal consumption and Taiwan twelfth. With almost no domestic coal resources, large existing coal capacity, and high per-capita energy demand, Japan ranked third, South Korea fourth, and Taiwan fifth for coal imports in 2014, behind China and India.

- **Southeast Asia**: in 2015, an additional 6.8 GW of coal-fired capacity came online in the region (Cambodia, Indonesia, Laos, Malaysia, Myanmar, Philippines, Thailand and Vietnam), bringing total new capacity since 2010 to 23.5 GW. In addition, the announced, permitted, and pre-permit capacity rose to over 115.4 GW—the third highest as a region for coal proposals after East and South Asia. However, a total capacity of 38.5 GW has already been halted/paused.
- **South Asia**: India is second only to China in the amount of proposed coal power capacity in the pipeline (218 GW), under construction (72 GW), and newly operating (19 GW in 2015). The IEA (2015) projected that India, along with Southeast Asia, would continue to drive global coal power growth. However, while India continues to construct new coal-fired plants, it has recently announced a greater drive toward the installation and utilisation of renewable energy, which may result in reduced dependence on coal-fired power generation in the future.
- **Africa and the Middle East**: 43 GW of coal-fired capacity has been announced (proposed) in the region, over half of which is at the preliminary stage of development. Meanwhile, an additional 11 GW is under construction, mostly consisting of the Medupi Power Station (4,864 MW) and the Kusile Power Station (4,864 MW) in South Africa, both planned for completion by 2021.
- **North America**: coal-fired power generating capacity in both the USA and Canada is on the decline. Furthermore, plans to build new export terminals in British Columbia, Washington, and Oregon have stalled due to environmental opposition and reduced demand in the Pacific markets. In Canada, regulations require new coal plants to have CCS technology.
- **Eurasia:** includes several countries with large coal reserves, such as Russia, Mongolia and Kazakhstan. Overall, the region has 2 GW of new coal-fired generating capacity under construction and 16 GW in various stages of planning/permitting development. Since 2010 only 2 GW of coal-fired capacity has been completed throughout Eurasia.
- **Europe (and Turkey):** the EU saw a drop in proposed coal-fired capacity to 11.8 GW in January 2016, down 8.4 GW from January 2015. The drop reflects the culmination of the 2014 EU agreement to reduce GHG emissions, growing public opposition to coal and coal financing, and the increasing deployment of renewables. In the remainder of Europe, the number of coal plant proposals faltered. Turkey, however, in 2016 continues to pursue large numbers of new coal plants and mines, with nearly 67 GW proposed and 3 GW under construction.

It is expected, even acknowledged, that renewable energy utilisation will continue to grow as part of the power mix. However, it must be noted that a shift in the mode of generation will incur costs and involve challenges. Historically, power production was designed around baseload generation facilities such as coal-fired power stations. Renewable resources generate only intermittently and distributed resources often deliver power back to the grid. These characteristics present unique challenges to utilities.

As the majority of new coal-fired power generation is in Asia, China and India alone account for >60% of global coal consumption (48% and 13% respectively), the following discussion focuses on this region.

In 2016, the Energy & Climate Intelligence Unit (ECIU) published a report that focused on coal in China, India, Indonesia and Vietnam. These countries, collectively, are reported to have 1,824 coal-fired power plants in the pipeline either planned or under construction, accounting for 74% of an estimated global new 2,457 coal-fired units. The report examines the likelihood that the IEA estimates, which indicate that India alone will account for half of the global coal demand growth to 2020 and Southeast Asia for another quarter, will materialise. It studies the potential slowdown of China's expansion in coal-fired capacity and the potential increase in India, Vietnam and Indonesia. The report considers that in China, the average capacity utilisation rate/factor (that is, the actual power produced over a period of time expressed as a percentage of the power that may have been produced if the station was running at full power for that period) has fallen, for coal, from 60% in 2011 to below 50% in 2015. For India, the load factor (that is, the ratio of the average load to the peak load during a period of time) has also fallen from a peak in 2008 of >78%, to <65% in 2015. The decline is attributed to slowing economic growth and environmental pressures combined with ambitious targets for energy efficiency and increasing renewable power generation. According to ECIU (2016), depending on trends in power prices, this may make new plants progressively less profitable, and as such, less attractive to investors. Nevertheless, *International investment in infrastructure and connectivity*, a report prepared under a technical cooperation arrangement between the ASEAN Secretariat and the United Nations Conference on Trade and Development (UNCTAD), Division on Investment and Enterprise, states that investment in the power and electricity sector infrastructure and connectivity increased in 2015. The state of the power and financial sectors in India was the subject of a review by CRISIL (2015). Companies from around the world are currently investing in the power and electricity sector in ASEAN countries. These include companies from China, France, Germany, Italy, Japan, Norway, Republic of Korea and the USA. The report includes references to a number of new coal-fired projects, their funding and sources (Hwee and Merza, 2015).

Coal-fired projects in the pipeline in China, India, Indonesia and Vietnam, according to the ECIU (2016) constitute a large proportion of world coal power projects. Together, they represent 82% of the 718 units globally under construction in 2016 (*see* Table 20).

Table 20 Proposed and under construction coal-fired power plant projects in China, India, Indonesia and Vietnam and the rest of the world, number of generating units (ECIU, 2016)

Country	Proposed plants	Plants under construction	Total
China	795	384	1179
India	297	149	446
Indonesia	87	32	119
Vietnam	56	24	80
Total	**1235**	**589**	**1824**
Global total	1739	718	2457
% share of China, India, Indonesia and Vietnam	71.02	82.03	74.24

From 2010-2015, approximately 2,300 coal-fired units were in the pipeline throughout the world. Some were completed, some were paused or shelved and some were cancelled. By the end of 2015, cancelled or shelved projects accounted for 53% of the total. When considering capacity, there was approximately 1,350 GW in the pipeline (completed/paused/shelved/cancelled) worldwide. Cancelled/paused/shelved projects accounted for 66% of the total. In the four Asian economies listed in Table 20, the proportion was 61% of capacity shelved or cancelled, varying from 43% in China to 80% in India. If the Paris Agreement on climate change (*see* Nalbandian-Sugden, 2015) is effective and global coal financing becomes progressively less conditional and more available (*see* OECD, 2015), it is expected that domestic policy in China, India and Vietnam will favour renewable energy and, where possible, nuclear. The ECIU (2016) report found that China's annual new build of coal-fired power plants may have peaked in 2015, as a result of over-capacity and a shift to renewables and nuclear energy has started. China has announced a target peak in overall coal consumption by 2020. Thermal power, largely coal, dominates China's installed electricity generating capacity, at 990 GW out of a total of 1,507 GW.

India's government has opted to base its 'Power for All' initiative (to increase power generation by 50% and bring reliable electricity to everyone by 2019) on an expansion of all generation options concurrently, including coal (domestic and imported), natural gas, solar, wind and nuclear power, plus grid upgrades and an energy efficiency improvements drive. However, India is adding 15-20 GW of coal-fired capacity annually, compared to a combined 6 GW of nuclear and renewable energy in 2014/15. Nevertheless, the government has doubled taxes on coal recently in an attempt to reduce its share in the mix. In addition, India has set ambitious targets for additional wind and solar power capacity of 140 GW by 2022, making renewables growth comparable with expected coal power capacity growth. India also has set a target to increase the installed capacity of nuclear energy by nearly 60 GW by 2032. A hydro-electricity investment programme is also starting after a decade of delays. Finally, the country has ambitious energy efficiency targets, for example, to achieve energy savings equivalent to one tenth of total current consumption (ECIU, 2016).

Approximately 8 GW of coal-fired power generation capacity was installed in Indonesia and Vietnam in 2015. In January 2016, Vietnam announced a review of proposed new coal-fired power plants, with a view to substituting some of these with natural gas and renewable power (ECIU, 2016). However, Indonesia plans to install an additional 35 GW of electricity generation capacity by 2020, of which 20 GW would be coal-based. Indonesia also aims to raise renewable energy, excluding traditional biomass, to 23% of the energy supply by 2025, from 6% currently. The target is set in the country's National Energy Policy of 2014 and is supported by a feed-in tariff (ECIU, 2016).

In 2016, the Coal Power Economics Study Group of North China Electric Power University published a report on the economics of coal-fired power generation projects in China. The Group analysed coal-power growth in 2015. It found a 2.3% annual drop in new build thermal power generation and 0.5% growth in total electricity consumption, and as such the Group considers the addition of new coal-fired (52 GW) capacity in 2015 is incompatible with demand. There is also approximately 73–79 GW capacity currently under construction in China, which collectively represents significant growth compared to increases recorded in the previous year. The Group considers that the disparity in supply and demand is further illustrated by the total installed capacity of coal-fired plant projects under the Environment Impact Assessment (EIA) approval announced by either the Ministry of Environment Protection (MEP) or its provincial counterparts in 2015. The total capacity announced amounts to 169 GW, of which 159 GW has been granted or pre-granted the EIA approval. This represents a significant increase when compared with the total EIA-approved installed capacity for the same period in 2014, which was 48 GW (*see* Figure 37). In March 2016, the National Development and Reform Commission (NDRC) and the National Energy Administration (NEA) issued a document urging all local governments and enterprises to slow the pace of coal-fired power plant construction. However, according to the Coal Power Economics Study group (2016), despite these efforts, coal-based power generation continues to increase mainly due to two factors. First, from January 2014 to March 2015, the approval of all projects for pulverised-coal power generation plants was delegated to provincial institutions from the NEA, the NDRC and the MEP. Second, historical guaranteed investment return, driven by the economic advantages of coal power in China, the past and current low coal price and the high on-grid tariff where the electricity is sold, has encouraged the growth in new installed capacity of coal power in excess of actual demand.

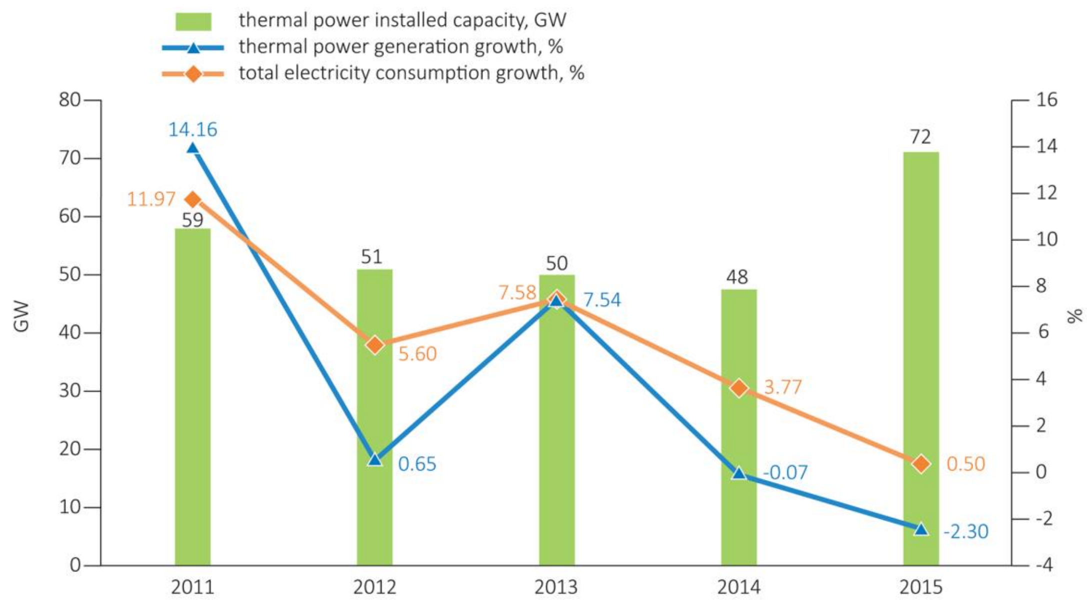


Figure 37 Thermal power installed capacity, power generation capacity growth and total electricity consumption growth during the Chinese 12th Five-Year Plan (FYP)
(Coal Power Economics Study Group, 2016)

However, the performance and profitability of the power sector varies between provinces. In 2015, the thermal power utilisation (hours) in Yunnan were recorded at 1,879 hours, while hours of operation in Sichuan were 2,682. In Gansu, <3,800 hours were recorded, while Jilin documented only 3,300 hours. In these provinces, the coal power sector contribution dropped below the break-even point more rapidly compared to other areas. The Coal Power Economics Study Group (2016), assessed the economics of the coal-fired power generation projects in six provinces; Shanxi, Inner Mongolia, Xinjiang, Hebei, Jiangsu and Guangdong. Selection of these particular provinces was based on: the abundance of coal power generation or status of a province as load centre, provinces with large portions of coal-fired generation projects under construction or newly approved, and with thermal power utilisation hours in 2015 at or higher than the national average (*see* Figure 38). These provinces also represent those with relatively good economies in coal-fired power generation projects in China at present.

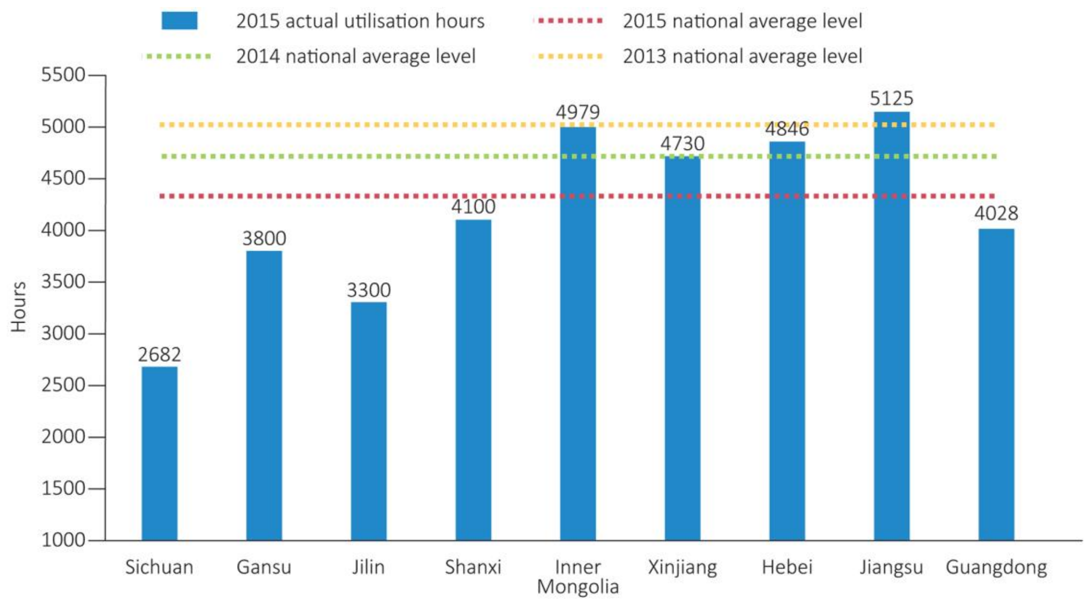


Figure 38 Current status of thermal power utilisation (hours) in Sichuan, Gansu, Jilin, Shanxi, Inner Mongolia, Xinjiang, Hebei, Jiangsu, Guangdong Provinces and national average levels in 2013, 1014 and 2015 (Coal Power Economics Study Group, 2016)

Using LCOE and other financial appraisal methods, the Coal Power Economics Study Group (2016) surveyed the economics of 600 MW newly-built coal-fired power units in different provinces and under multiple scenarios. A step-up accumulation methodology was adopted against the expected change in the external environment for coal power development to construct scenarios and anticipate the sequence and order of events, based on the probability and timing for the realisation of each scenario. As such, the Group first took into consideration the national on-grid tariff adjustment plans and the retrofitting requirements for ultra-low emission coal-fired plants that are currently in place. The study also included the carbon trading market expected to launch in 2017 in China, as well as electricity market reforms and the possibility of a coal price rebound. In brief, the study focused on providing a systematic outlook on the economic benefits of coal power generation to companies experiencing the potential changes in the external development environment during the '13th Five-Year Plan (FYP)' period (2016-2020). That is, the electricity market competition/reform and the continuous deterioration of the existing units-utilisation rate. Understanding China's electricity market reform from the perspective of the coal-fired power disparity was the subject of a study by Mou (2014).

The findings of the report were summarised by the Coal Power Economics Study Group (2016) as follows. The continuous decline in coal prices resulted in lower power generation costs for all power generating companies across all provinces. As there was insufficient adjustment to the benchmark on the grid tariff, coal power generating companies made unprecedented profits. However, such profitability is not sustainable in the long-term. If the power generation companies decide to expand their capacity based on short-term profitability, they will be exposed to the long-term risks of incurring losses and failure to recoup their investment. During the 13th FYP period, the external environment for coal power development could change greatly, and the economics of coal power generation companies can thus be affected. This may be due to the more stringent policy and environmental requirements, increasing pressure to reduce carbon emissions and price competition under electricity market reform. The study found that except for Hebei and Jiangsu, the coal-fired power generation projects in the remaining typical provinces cannot reach benchmark rates of return. They will therefore be unable to recoup their investment during their lifetime. Additionally, when the Group considered the change of two sensitivity factors in the study, namely the unit utilisation rate and the degree of reduction in tariff for direct power purchase, they determined that the coal-fired power generation projects in all selected typical provinces would be unable to recoup their investment during their lifetime.

The results from the analyses carried out in the study indicate that a new tariff adjustment plan issued by the NDRC at the end of 2015 will have a significant impact on coal-fired power generation projects in Xinjiang, resulting in failure to recoup full investment. Furthermore, in areas with additional environmental constraints and the electricity market reform, the expected internal rate of return from coal-fired power generation projects (for example, in Shanxi) will fall well below the benchmark value of the industry. Areas such as Hebei, Jiangsu, Inner Mongolia and Guangdong, however, have profit forecasts expected to remain above the benchmark rate of return for the industry. Meanwhile, the China Electricity Council (CEC) forecast that electricity consumption in 2016 would grow by 1–2%, that there will be at least 50 GW addition in coal power installed capacity, but with the increasing contribution of renewable energy to the market, there will be a continuous fall in coal power utilisation hours (somewhere between 300 and 400 hours). If electricity demand growth remains relatively low and the construction of coal power installed capacity remains high in 2017, the utilisation rates of coal-fired plants will continue to decline. Therefore, the Coal Power Economics Study Group (2016), based on the scenario prospect analyses in their report, select 2020 as the year when there will be losses to the whole coal-power sector. However, if the electricity demand growth continues to be at a low level (that is, <2% annually) and the scale of units newly commissioned remains at a high level (for example, an annual addition of ~50 GW), the losses of the coal power sector as a whole may be realised earlier in 2017.

Policy suggestions made by the Coal Power Economics Study Group (2016) include formulation of strategic power plans adapted to the new economic norm in China, that is slower rate of growth, electricity market reform, reduced demand for electricity as well as strict environmental requirements. The Group considers that such plans should provide for low-carbon power transformation, arrange sufficient lead time for completion of 20% non-fossil energy targets by 2030, set up the coal-fired power development targets in strict compliance with the principle of prioritising renewable energy, demand side energy, and control investment in coal-fired power generation (Coal Power Economics Study Group, 2016).

According to WEC (2013), the likelihood of a significant amount of new coal generation coming online in Europe, the USA and Australia is low. WEC (2013) assumed a 10% cost of equity for a base hurdle rate in their study, but indications were that actual hurdle rates demanded by investors to agree to supply capital to a new build coal plant may be in the order of 18% or higher. In both Europe and Australia any new coal-fired plant would be subject to an uncertain future carbon price, which is the main reason why investors consider these plant risky. However, in some parts of Europe, new coal plants continue to come online, for example, in Germany where the nuclear ban and other market-specific factors are likely to necessitate new additions for the next few years. Coal-based power generation continues growing in parts of South America but China, India and Southeast Asia are the main markets for new coal development. Finally, despite the growth in renewable capacity, fossil-fuel generation capacity will continue to grow in absolute terms in all scenarios, although its relative contribution is forecast to fall from 67% in 2012 to 40-45% by 2030. The growth in coal capacity is expected to slow significantly due to the imposition of carbon pricing schemes and environmental concerns, especially in terms of climate change and air quality.

6 Conclusions

An *operating ratio* shows the relationship between a company's operational costs versus net sales/revenue. Comparison of operating ratio within a company over time indicates the change in the operational efficiency of the company over the years. In this review, the operating ratio is the terminology used to evaluate the operation of a power generating company. It is based on operating costs and income and not influenced by variations in a company's capital structure or financing decisions (such expenses are non-operational costs). In addition, the operating ratio is an indirect measure of the company's operational performance, and therefore profit efficiency. The lower the ratio, the more efficient the company operations are and therefore the greater the profit.

The operating ratios calculated in this review indicate receding profit margins in the power generating industry as a whole. The main reasons for the shift in power utilities' financial performance may be attributed to the changeability or volatility in fuel prices, the subsidies affecting not only the construction of new plants but also end-user electricity tariffs, increasing customer focus on renewable, low carbon energy, the globalisation of the supply chain, and environmentally driven government sourcing guidelines in some countries and mandatory requirements in other countries. The operating ratio calculation in this report was undertaken simply to indicate the operational efficiency of major power generating companies' year-on-year and, show where the operating ratio improved and/or deteriorated. The operating ratios of the companies ***must not*** be compared as the information provided in the consolidated annual financial statements used for the calculations differs from one corporation to another in that there is no breakdown of exact operating costs, for example, where it is unclear whether staff/personnel costs are included or not.

The variability and uncertainty of wind and solar energies can impact grid operations. One impact of the increasing utilisation of these energy sources is that coal-fired power plants have to cycle more frequently. Cycling refers to the operation of a power generating unit at varied load levels, including start-ups and shut-downs (on/off), load following and minimum load operation. The fluctuating plant operation is in response to changes in system load requirements. With every start-up and shut-down, the boiler, steam lines, turbine, and auxiliary components undergo large thermal and pressure stresses, which cause damage. This damage is exacerbated for high temperature components by the phenomenon known as creep-fatigue interaction. Creep is a time-dependent change in the size or shape of a material due to constant stress (or force) on that material. In fossil-fuelled power plants, creep is caused by continuous stress that results from constant high temperature and pressure in a pipe or a tube that occur during steady state baseload operation. Fatigue is a phenomenon leading to fracture (failure) when a material is under repeated, fluctuating stresses, which is exactly what occurs in cycling. In a fossil fuel-fired power plant, such fluctuating stresses result from large transients in both pressures and temperatures. These transients typically occur during cyclic operation. However, cycling-related increases in critical component failure rates may not be observed immediately. The shortening of component life expectancies due to cycling can result in higher plant equivalent forced outage rates (EFOR) as well as higher capital and, operation and maintenance costs to replace components at or near their end of service lives. In addition, it may result in reduced overall plant lifespan. The advent of such detrimental effects depends on the amount of creep damage and the specific types and frequency of the cycling.

Controlling the costs of O&M including materials/components management and inventory control can improve operating ratio and are major concerns for all power generating companies. The conversion of baseload plants to cycling units, and the extension of intervals between scheduled outages, is changing power plants operation as well as maintenance. In addition, with the increasing competitiveness of the electric power markets, staffing levels have decreased whether due to cost of labour or a drive to greater efficiency. As a result, plant operators have turned, and continue to turn to outsourcing some or all of the maintenance and materials management. However, the tendency to outsource O&M services is, in general, practised more widely in Europe, Japan and the USA, for example, while ASEAN countries tend to use in-house staff to carry out all plant O&M. Where some or all O&M services are outsourced, it is important that the service contracts define all operational and maintenance activities that address efficient operation. These should include methods to track operating changes, improvements, deficiencies over time as well as include record keeping of activities to detect and troubleshoot maintenance and operational problems. The recorded documentation would provide staff and management with critical data for comparing past and present conditions of the plant equipment and performance. A tracking preventive maintenance approach would also assist plant personnel to locate recurring problems, to understand when equipment performance is degrading, and ensure that the contractor is performing the tasks outlined in the contract.

Finally, the likelihood of a significant amount of new coal generation coming online in Europe, the USA and Australia is low. However, in some parts of Europe, new coal plants continue to come online. Coal-based power generation continues growing in parts of South America but China, India and Southeast Asia are the main markets for new coal development. Despite the growth in renewable capacity, fossil-fuel generation capacity will continue to grow in absolute terms in all scenarios, although its relative contribution is forecast to fall from 67% in 2012 to 40–45% by 2030. Many of the conventional, existing coal-fired power plants today were built prior to the expansion targets for and adoption of intermittent wind and solar photovoltaic power. In many of these plants, measures to allow greater flexibility have been implemented subsequently, so that power plants can meet increased requirements for market load adjustments. As a result, many baseload power plants have been modified or are taking the necessary steps to allow for flexible operation at reasonable cost.

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