Combining solar power with coal-fired power plants, or cofiring natural gas

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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

Operators of coal-fired power plants seek ways to increase the efficiency and extend the working lives of their plants by improving the operational flexibility and reducing the environmental impact. Two possible options are explored: combining solar energy with coal-fired power generation, and cofiring natural gas in coal-fired power plants. Both techniques show potential. Depending on the individual circumstances, both can increase the flexibility of a power plant whilst reducing its emissions. In some cases, plant costs could also be reduced.

Clearly, any solar-based system is limited geographically to locations that receive consistently high levels of solar radiation. Similarly, although many coal-fired plants already burn limited amounts of gas alongside their coal feed, for cofiring at a significant level, a reliable, affordable supply of natural gas is needed. This is not the case everywhere.

But for each technology, there are niche and mainstream locations where the criteria can be met. The need for good solar radiation means that the uptake of coal-solar hybrids will be limited although cofiring gas has wider potential – currently, the largest possible market is for application to existing coal-fired plants in the USA. However, where gas is available and affordable, there are also potential markets in some other countries.

Acronyms and abbreviations

CBM	coalbed methane
CCGT	combined cycle gas turbine
CCS	carbon capture and storage
CMM	coal mine methane
CSP	concentrated solar power
DFO	dual fuel optionality
DNI	direct normal irradiation
ECG	enhanced gas cofiring
EPA	Environmental Protection Agency (USA)
EPRI	Electric Power Research Institute (USA)
ESP	electrostatic precipitator
EU	European Union
FGD	flue gas desulphurisation
FLGR	fuel lean gas reburning
GE	General Electric
HCE	heat collecting element
HESI	high-energy spark ignition
HTF	heat transfer fluid
HP	high pressure
IEA	International Energy Agency
IP	intermediate pressure
LCOE	levelised cost of electricity
LFR	linear Fresnel reflectors
LNB	liquefied natural gas
MATS	Mercury and Air Toxics Standards (USA)
MCR	maximum continuous rating
MHPS	Mitsubishi-Hitachi Power Systems
NREL	National Renewable Energy Laboratory (USA)
OECD	Organisation for Economic Cooperation and Development
O&M	operation and maintenance
PV	photovoltaic
RPI	Riley Power Inc.
SCR	selective catalytic reduction
SNCR	selective non-catalytic reduction
SAPG	solar-aided power generation
SH	superheated
SPR	solar particle receivers
SSG	solar steam generator
STE	solar thermal electricity
UCG	underground coal gasification

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1 Introduction – coal solar hybrids

Many economies are attempting to reduce their reliance on fossil fuels by replacing them with renewables such as wind and solar power. There is growing interest in the production of sustainable energy and the provision of reliable, low cost sources of renewable energy. This has prompted many utilities to examine alternatives to the fossil fuels that have traditionally provided the bulk of their electricity output.

Fossil fuels such as gas and coal are still vitally important in generating much of the world's electricity and in many countries, continue to provide reliable low cost supplies. Electricity generated by renewables such as wind and solar is more expensive. In many economies, renewables are heavily subsidised, costs that are passed on to the end-user. The other major drawback is that they are weather-dependent. Hence output is intermittent and can vary widely and in a short space of time. Consequently, other generation systems (such as coal- and gas-fired plants) are needed to provide back-up when supply is inadequate or unavailable.

Although developments remain ongoing, cost-effective utility-scale storage of excess electricity produced by renewables at periods of low demand is not yet possible. Thus, the diffusion of renewable energy into a power system often implies high supply variability, and the current lack of large scale economically viable electricity storage options means that the integration of renewables has so far been possible thanks largely to the presence of fast-reacting mid-merit fossil-based technologies acting as back-up capacity (Verdolini and others, 2016; Barber, 2016). Based on data from 26 OECD countries (from between 1993 and 2013) an estimated 8 MW of back-up capacity is required for each 10 MW of intermittent renewables capacity added to a system.

Solutions for combining the output from coal-fired generation in novel ways continue to be explored, although their limited capacity can be problematic. For example, Spanish power company Endesa is considering adding battery storage to its 1.16 GW coal-fired Carboneras plant. This is in direct response to the increased amount of electricity fed to the grid from variable renewables. Like many others, the plant was originally built to operate on base load, and the increased cycling puts stresses on plant components, pushes up maintenance and inspection costs, increases coal consumption, and produces unnecessary emissions. The storage project is at an early stage in its development although it appears that it will rely on lithium-ion batteries, capable of storing only 30 minutes' worth of the plant's output. Industry opinion is that the use of batteries coupled to a coal plant in this manner is unlikely to have a major impact within the power sector – it is likely to be a one-off. Battery storage is finding limited application for peaking duties in, for instance, Southern California. However, analysts suggest that in order for battery plants to be profitable, the total price of an installed project will need to fall from the current 500 US$/kWh to less than US$275. Their limited capacity is also a major issue.

However, there are clear incentives to explore options for combining intermittent renewables such as solar power with conventional thermal power plants such that each provides advantages to the other, in the process, creating a cleaner more efficient generating system. One possible option is to combine solar thermal power with coal-fired generating capacity – so-called coal-solar hybridisation. This option is explored in detail in Chapters 3–6. The potential role of thermal storage is also considered.

A further option to improve flexibility and reduce emissions from coal-fired power plants is to cofire with natural gas. This avoids the intermittency issues of solar, but retains some of the disadvantages of fossil fuels in general. This concept is explored in Chapter 6.

2 What is a hybrid power plant?

Around the world, utilities are examining a range of hybrid power options. However, in reality, some power plants referred to as 'hybrids' are merely co-located generation facilities. For example, a combined-cycle gas turbine (CCGT) plant might add photovoltaic (PV) solar cells to the site. Clearly, these solar assets generate electricity, but this is fed into the grid independently of the gas-fired plant. Under this type of arrangement, the solar facility may serve to diversify the economic interests of the plant's owner or reduce the overall environmental footprint of the site, but the PV and CCGT are not as tightly integrated as they might first appear (Miser, 2016).

Media reports have a tendency to describe some projects in development as 'hybrids', when this is clearly not the case. For example, India is planning to install a significant amount of solar energy, some of the new facilities being located at existing coal-fired power plants. Most of this new solar-based capacity will take the form of PV installations. These will generate electricity that will be fed to the grid independently of that from the coal plant. Thus, although these two technologies will share a site and some assets such as grid connection, in reality, they will operate largely as independent units and not as integrated hybrids. The concept of co-locating several generating systems is not limited to coal-fired plants and there are a number of sites that combine gas-fired generating capacity with PV. For instance, in the USA, there are plans for a new 750 MW power plant in New Mexico. This will comprise a combined cycle gas turbine power plant of 680 MW operating on base load, with a 70 MW PV facility that will be used to provide peaking generation capacity. However, both systems will essentially operate independently of the other.

There are other types of power plants that are true hybrid facilities. These operate under an entirely cooperative arrangement in which two or more sources of energy are harnessed to create separate but parallel steam paths. These paths later converge to feed a shared steam-driven turbine and generate electricity as a combined force – for example, a facility that uses concentrated solar power (CSP) combined with a conventional coal-fired power plant. This form of hybrid technology integrates these two disparate forms of power so that they combine the individual benefits of each. This approach can replace a portion of coal demand by substituting its energy contribution via input from the solar field. Thus, during daylight operation, solar can be used to reduce coal consumption (coal reducing mode). As the radiation decreases during the latter part of the day, the coal contribution can be increased, allowing the plant's boiler to always operate at full load. When radiation increases again, the process is reversed, with solar input gradually reducing that of coal. Alternatively, input from the solar field can be used to produce additional steam that is then fed through the steam turbine, increasing electricity output (solar boost). Whichever mode is adopted, the design and integration of the solar field into the conventional system is critical for the proper functioning of a hybrid plant. In principal, this form of hybrid technology can be applied to any form of conventional thermal (coal, gas, oil or biomass-fired) power plant, either existing or new build.

3 Solar power systems

Of the renewable technologies, wind and solar power are currently making the most headway. In the case of solar, there are several possible ways in which the sun's radiation can be harnessed. The most commonly encountered system is photovoltaic (PV), where PV cells convert solar radiation directly into electricity. The other is solar thermal, usually in the form of concentrated solar power (CSP), where radiation is used to produce heat (Figure 1). CSP systems generally rely on a series of lenses or mirrors that automatically track the movement of the sun. These focus a large area of sunlight into a small concentrated beam that can be used as a heat source for a conventional thermal power plant. In all types of system, a working fluid (such as a high temperature oil or increasingly, molten salts) is heated by the concentrated sunlight, then used to raise steam that is fed into a conventional steam turbine/generator. In addition to the solar collection system, a stand-alone CSP plant (not hybridised) also requires many of the systems and components such as steam turbine/generator found in a conventional power plant.

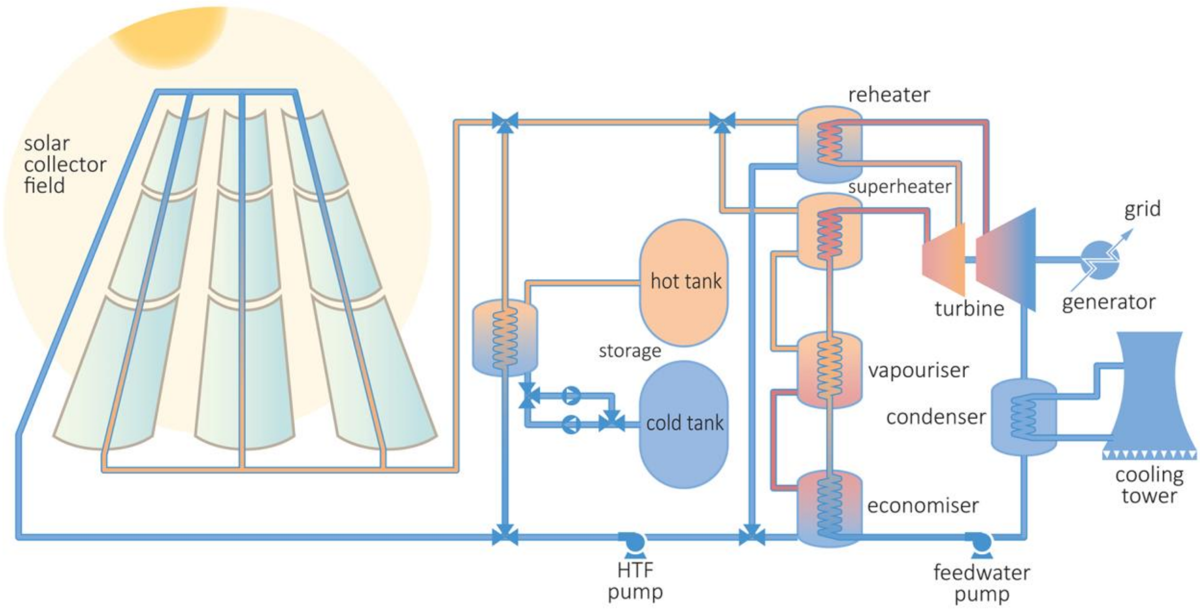

Figure 1 Solar thermal trough power plant with thermal storage

There are a number of solar collection systems available commercially, some more effective than others. Systems that use two-axis tracking to concentrate sunlight onto a single point receiver (tower and dish systems) are more efficient than linear focus systems. Where they form part of CSP plants, they can operate at higher temperatures and hence generate power more efficiently. However, they are also more complex to construct. The four main types of solar collection systems comprise:

- Parabolic trough systems – solar energy is concentrated using sun-tracking parabolically curved, trough-shaped reflectors onto a receiver pipe that runs along the inside of the curved surface. The temperature of the heat transfer fluid (often thermal oil) is increased as it flows through the pipe. Trough designs can incorporate thermal storage that allows electricity generation to continue into the evening or during cloudy days. Some parabolic trough plants use fossil fuels to supplement the solar output during periods of low solar radiation;

- Linear Fresnel systems – an alternative system that relies on the use of segmented mirrors instead of troughs;
- Power Tower systems – or central receiver systems utilise sun-tracking mirrors (heliostats) to focus sunlight onto a receiver at the top of a tower (Figure 2). A heat transfer fluid is heated in the receiver up to ~600°C and used to generate steam that is then fed to a conventional turbine-generator. Several heat transfer media have been used – early systems used steam, although later designs have increasingly opted for molten salts because of their superior heat transfer and energy storage capabilities; and
- Parabolic dishes – reflect solar radiation onto a receiver mounted at the focal point. They usually use two-axis tracking systems to follow the sun. The heat collected can be used directly by a heat engine mounted on the receiver moving with the dish structure. Stirling and Brayton cycle engines are currently favoured for power production.

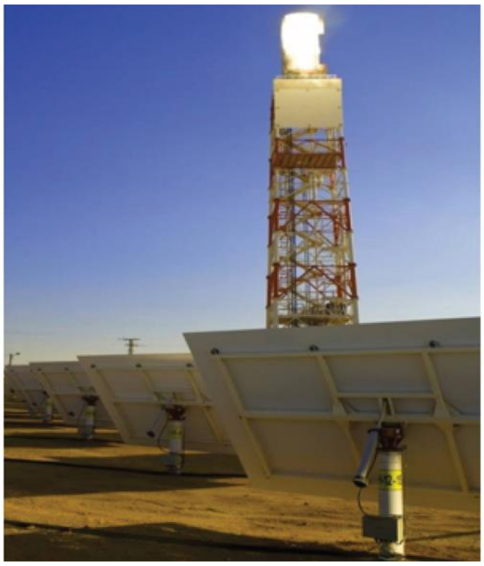

Figure 2 Tower-based solar thermal steam generator (photograph courtesy of Foster Wheeler Power Group)

The main solar-based alternative to CSP is PV. Over the last decade, its use has burgeoned and most forecasts suggest that for the foreseeable future, deployment is likely to continue increasing. Although the cost per unit of electricity is currently generally higher than that from conventional fossil fuel-fired capacity, recent years have seen the cost of PV-produced electricity fall – forecasts by the International Energy Agency (IEA) suggest that under suitable conditions, solar PV could eventually fall to 4 US cents/kWh (Parkinson, 2014). The IEA predicts that the cost of all solar technologies will continue to fall further in the coming decades. Utility-scale solar is expected to be around the same level, and solar thermal with storage ~6.4 US cents/kWh (Table 1). Understandably, the lowest prices tend to be in regions that experience the greatest sunshine. The IEA suggests that solar-based systems could become the biggest single source of energy by 2050.

Table 1 Projected levelised cost of electricity for PV and solar thermal electricity (STE) (Parkinson, 2014)

Cost (US$/MWh)		2013-15	2020	2030	2040	2050
Utility scale PV	Minimum	119	96	56	45	42
	Average	177	133	81	68	54
	Maximum	318	250	139	109	97
Rooftop PV	Minimum	135	108	63	51	45
	Average	210	157	102	91	78
	Maximum	539	422	231	180	159
Solar thermal electricity	Minimum	146	116	86	69	64
	Average	168	130	98	77	71
	Maximum	213	169	112	101	94
CO_2 price (US$/t$CO_2$)			46	115	152	160

There are significant differences between the two main solar-based technologies (PV and CSP). Both are significantly different in their makeup and how they operate. Solar power equipment supplier Abengoa considers that the main features and advantages of each are those summarised in Table 2.

Table 2 Main features of solar thermal and photovolatic power systems (Abengoa, 2015)

Solar thermal systems	Photovoltaic systems
Dispatchable renewable energy	Intermittent renewable energy
Efficient and cheap storage available	No commercially viable utility-scale storage available
Can supply 24/7 when needed	Supply only when source available (when sunny)
Supports the grid	Needs back-up power
Can substitute conventional power generation (either at peak demand or on base load)	Further investment needed for backup
High initial investment requirements	Lower initial investment requirements
Centralised generation/utility scale	Distributed generation/utility or small scale

A further advantage of solar thermal-based systems over PV is that they offer the possibility of integrating with conventional generation assets such as coal- and gas-fired power plants.

In many countries, the PV sector continues to benefit from further funding and development activities. For example, the US Department of Energy (US DOE) is providing US$107 million via the Office of Energy Efficiency and Renewable Energy's (EERE) *SunShot Initiative*. This funds various projects aimed at improving PV performance, reliability, and manufacturability. One of SunShot's overriding goals is to drive down the levelised cost of utility-scale solar electricity to ~6 US cents/kWh without incentives by 2020 (Energy Central, 2016). An additional aim is to reduce costs of PV-based systems in general, a trend that is already evident. The US DOE's National Renewable Energy Laboratory (NREL) considers that this will result from lower module and inverter prices, increased competition, lower installer and developer overheads, improved labour productivity, and optimised system configurations.

Cost reductions have also been reported for other parts of the world, although the cost-effectiveness of stand-alone CSP is acknowledged to vary enormously with system configuration and location. In some situations, under current conditions, CSP technology is viewed as too expensive to justify the capital outlay. However, the cost-revenue gap is expected to close as technological advances are made and costs reduce. For example, studies undertaken in 2012 into the technology's potential in Australia concluded that CSP had features that acted in its favour, but that under conditions prevailing at the time, the levelised cost of electricity (LCOE) from stand-alone CSP would be roughly double that of utility-scale electricity in main grid-connected markets. At the time, CSP projects were not considered to be commercially attractive in Australia (IT Power, 2012). However, since then, the LCOE for both PV and CSP systems has continued to fall and in some situations, this could lead to their re-evaluation.

The main disadvantage of solar-based systems is their inherent variability. At night time or in unfavourable weather conditions, output reduces or stops entirely. Some CSP plants have incorporated a secondary energy supply that allows them to continue operating when the level of solar radiation is inadequate. This allows the continued generation of dispatchable electricity and guarantees an alternative thermal source that can compensate for night time thermal losses, prevent freezing and assure faster start-ups in the early morning. In most cases, this has involved the addition of a gas-fired boiler brought online when required, allowing extended periods of operation (IEA Solar Technology Roadmap, 2014). Clearly, from an environmental perspective, this negates some of the CO_2 emission reductions accrued through the use of solar. More recently, focus has shifted towards the use of solar thermal energy storage systems (*see* Chapter 4).

3.1 Coal-solar hybrids

It is against the background of increasing deployment of solar-based systems that the concept of combining solar with conventional coal-fired power generation is being explored. This approach offers a route to combining renewable energy with inexpensive stable output from existing (or new build) thermal generation assets. In suitable locations, solar radiation can be harnessed and used to raise steam that can be fed into an existing conventional coal-fired power plant (a coal-solar hybrid). In such a system, solar thermal energy can be used to produce high pressure and high temperature steam that can be integrated into an existing power plant's steam cycle in several ways such that power output is boosted and/or coal consumption reduced.

Most existing solar thermal designs operate at ~300–400°C, lower than that of a typical modern coal-fired power plant (operating at 500°C or more). Thus, the temperature of the steam from the solar field is not high enough and further heat must be provided before it can be fed to the plant's steam turbine(s). Feeding steam produced by the solar collection system directly into the main turbine can increase the overall efficiency of the plant by making the best use of the steam output from the solar field. However, the conditions of the steam generated by this must be matched to the coal-fired steam turbine cycle – this can be an engineering challenge (Zhu, 2015). Alternatively, solar thermal energy can be used to heat the feedwater prior to entering the boiler. In a conventional steam power plant, as feedwater enters the feedwater heater, steam is extracted from the steam turbine to heat it. When solar heat is added to the feedwater, less steam is extracted from the turbine; this reduces coal input, increases the unit electrical output, or both.

Potentially, there are a number of points where steam generated from solar power could be fed into a conventional coal-fired power plant. This will be influenced partly by the type of solar collection system employed as these tend to operate at different temperature ranges. Thus, candidate locations for steam from trough-based collectors include feedwater heating, low pressure cold reheat, and high pressure steam between the evaporator and superheater. In the case of power towers, possible locations are similar to those from troughs, but would also allow higher temperature admissions to hot reheat or main steam circuits. Possible locations from systems using Compact Linear Fresnel Reflectors include feedwater heating, and low pressure cold reheat (Miller, 2013). Thus, the main applications are preheating of boiler feedwater, additional preheating of feedwater downstream from the top preheater, and the production of intermediate pressure (IP) steam or main steam (Siros, 2014; Roos, 2015). The merit order of the various hybridisation modes is shown in Table 3, although project-specific constraints will have an impact on the order.

Table 3 Merit order of hybridisation modes (Siros, 2014)

Option	Comment
Solar preheating of high pressure (HP) feedwater	Boost mode – top preheater ranks first
Additional solar preheating of feedwater	Coal saving mode
Solar heating of low pressure feedwater	Boost mode – especially deaerator
Solar production of HP/IP steam	Coal saving mode

Some existing coal plants are particularly well suited to hybridisation as they already allow operation in boost mode. As a turbo-generator often has a capacity margin, this is achieved by closing the highest-pressure steam extraction (but with an efficiency penalty) (IEA Solar Technology Roadmap, 2014). To date, feedwater heating has been the focus of several projects (Figure 3). On coal-based power plants, feedwater is preheated before entering the boiler in order to improve the cycle efficiency. This is achieved through the use of a train of preheaters that extract steam from the turbine at various pressure levels. By replacing the highest-pressure steam extractions with solar steam (fully or partially), water preheating can be maintained whilst expanding more steam through the turbine, thereby boosting its power output (IEA Solar Thermal Roadmap, 2014).

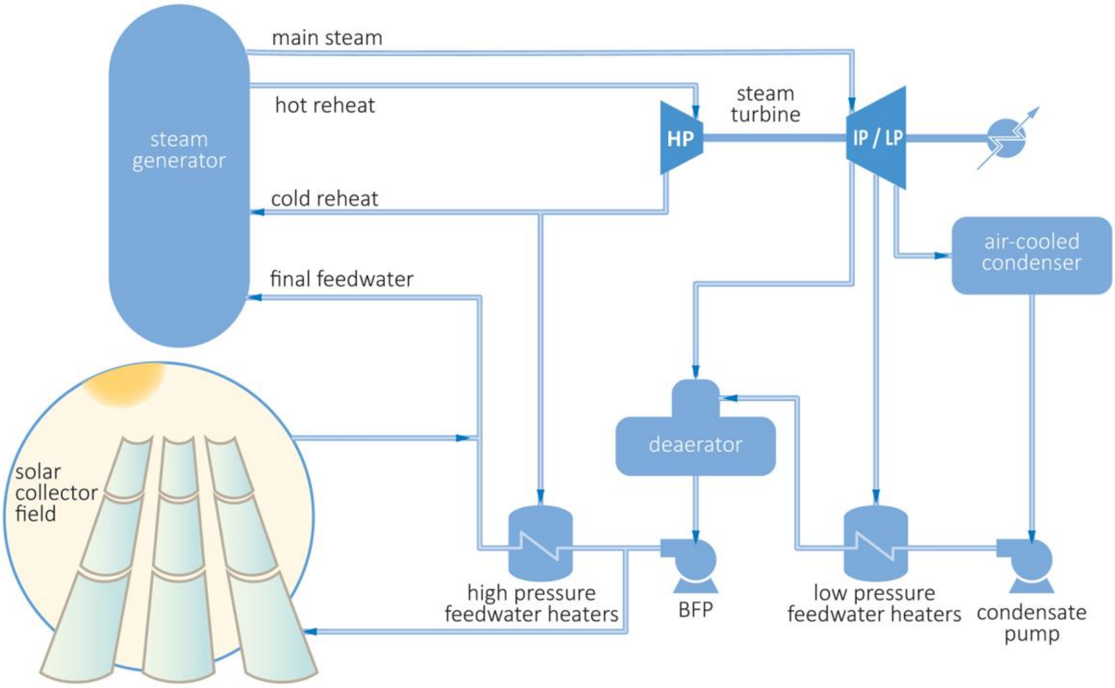

Figure 3 Power plant feedwater heating using solar thermal power

It is anticipated that some developing countries will build CSP plants as well as new coal-fired units; they may already operate the latter. Thus, there are a significant number of potential sites, both existing and new-build, in countries that benefit from a good supply of solar energy (Siros, 2014). The incorporation of solar energy into an existing coal-fired power station has the potential to increase overall plant efficiency, reduce coal demand and CO_2 emissions, plus minimise the problem of solar power's variability. At night, or when solar intensity is low, the output from the coal plant can be increased accordingly, allowing the combination to operate on an uninterrupted basis 24-hours a day. When adequate solar intensity resumes, the coal plant can be ramped down once again. Alternatively, the increased steam flow produced by the solar boiler can be fed through the existing steam turbine, boosting output (so-called 'solar boost'). An important point is that incorporating solar energy in this manner will cost less than an equivalent stand-alone CSP plant as many of the systems and infrastructure of the coal plant, such as steam turbine and grid connection, are already in place. A stand-alone plant requires all such systems in order to function. The LCOE from a coal-solar hybrid will be lower than that of a stand-alone CSP plant, and able to compete with that produced by PV systems (Siros, 2014).

Solar collection systems normally operate using focussing mirrors or similar that track the sun's path and concentrate solar radiation onto a central point(s) where the heat is transferred to a heat transfer fluid. This is then used to raise steam that is fed into the coal plant and expanded through conventional steam turbines. As noted, the heat generated can be fed into the water/steam circuit of the coal plant to boost power output, and/or reduce coal demand. Potentially, there are several possible places for this steam to be injected into a conventional Rankine cycle – this is the fundamental operating cycle where an operating fluid is continuously evaporated and condensed; it is used in the vast majority of conventional steam-based thermal power plants.

Steam turbines in most power plants have an excess capacity margin that allows increased output. By incorporating solar-derived steam, the amount of steam bled off the turbine for feedwater heating (which creates an efficiency penalty) can be reduced. This makes more steam available for expansion through the turbine, increasing its output (boost mode). The main modifications required to the coal-fired plant's steam cycle are often limited largely to the heat recovery steam generator (HRSG) which must be capable of handling the steam coming from the solar steam generation system.

In recent years, a number of coal-solar hybrid projects have been developed or proposed; some have focused on solar boost via feedwater heating, whereas others have adopted alternative hybridisation configurations such as solar boost with superheated (SH) steam fed into a cold reheat pipe, and coal saving with additional feedwater preheating after the power plant's top preheater (Siros, 2014). Figure 4 shows the general concept of generating high pressure steam using solar energy.

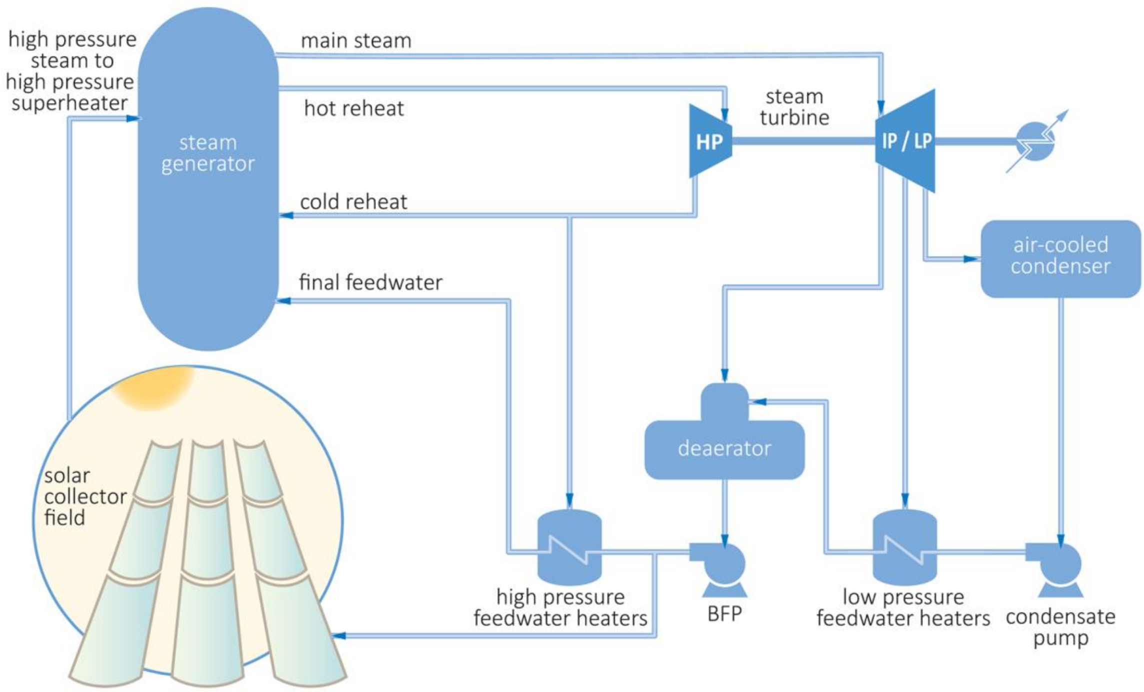

Figure 4 Generating high pressure steam using solar power

Clearly, any solar-based systems can only operate effectively in locations where the daily level of sunshine is adequate. A further requirement for coal-solar hybrids is the availability of suitable land close to the existing power plant, needed for the solar collection system. Up to several thousand hectares may be required. Usually, CSP technology involves concentrating sunlight onto a receiver that contains a heat transfer medium, either oil-based fluid or a molten salt. Several types of solar collection devices are available commercially, and the choice will be influenced by factors such as land availability. The solar collector field can comprise 30–50% of the cost of a CSP plant.

Around the world, recent years have seen the application of CSP grow steadily. Many industry observers consider that the technology can provide a route for harnessing the huge solar resource with potentially better dispatchability than via PV cells. Furthermore, if integrated with conventional fossil fuel power plants the 'coal-solar hybridisation' option CSP capacity can be built with lower costs. As such, hybrids could provide a route to implementing and maturing the technology, at lower cost than for new greenfield installations. An additional bonus of hybridising is that by eliminating part of the coal feed, plant emissions can be reduced. Under some circumstances, the addition of a renewable energy source to a coal-fired plant ('greening' existing coal-fired assets) could allow access to feed-in tariffs or other forms of subsidy. Compared to conventional fossil fuel-fired power plants, the cost of electricity produced from solar power remains high. However, potentially, solar augmentation could provide the lowest cost option for adding solar power to an existing generation fleet (EPRI, 2010a).

Some existing coal plants are particularly well suited to hybridisation as, assuming that the turbo-generator has the corresponding capacity margin, they already allow a 'boost mode' by closing the highest-pressure steam extraction. Hybridising in this manner could provide a power boost without extra coal consumption. If the solar potential exceeds the turbine's extra capacity, coal-saving is possible. On current coal-solar hybrid plants, solar steam feeds only the highest-pressure preheater, but other hybridisation concepts could be adopted and combined to increase the solar share, especially on greenfield projects (Siros and others, 2012). Such solar boosters increase capacity and energy generation without extra coal consumption, and with virtually no other extra cost than that of the solar field (IEA Solar, 2014).

3.2 Advantages of coal-solar hybridisation

The concept of combining coal and solar-based systems may appear counterintuitive. However, the idea has gained traction as hybridisation is often considered more effective, reliable, and less expensive than relying solely on PV-based generation (Kho, 2012).

Although renewable energy systems such as solar are attractive on environmental grounds, they face two principal challenges, namely their inherent variability, and that they usually require some form of support or subsidy to be considered economically viable. Potentially, a coal-solar hybrid is an elegant solution. Such a partnership can offer the environmental benefits of solar power, but with the advantage of shared costs of major plant equipment. This significantly lowers the lifetime cost of energy of the solar component. Combining these two types of generation within a single power cycle capitalises on the strengths of both. Importantly, developers consider that, from a grid operator perspective, a coal-solar (and gas-solar) hybrid can be considered fully dispatchable (Appleyard, 2015).

There are a number of reasons why power utilities might find coal-solar hybrids more attractive than PV. There is no requirement for new turbines, grid connection and other major systems as most of these are already in place. Furthermore, particularly when running in boost mode, the overall system operates in a manner familiar to utilities. The cost of electricity from a hybrid could be between a third and a half that from a stand-alone CSP plant – this is mainly because there is little extra cost apart from the addition of the solar field (Siros, 2014; Zhu, 2015).

A further advantage of CSP over PV systems is that the land area required per unit of electricity generated is normally much less. For example, solar supplier AREVA's steam generators are used in various CSP applications around the world – they are claimed to generate between 1.5 and 2.6 times more peak energy per hectare of land than PV.

As solar projects tend to generate most electricity on hot days when there is likely to be high demand from air conditioners, adding solar to conventional power plants could reduce the requirement for peaking power plants. This could cut peak electricity costs, given that such plants are only brought on line at times of peak demand and deliver the most expensive electricity.

As there is more inertia in the system, output from a solar-thermal-based plant will fluctuate less than an equivalent PV facility. This minimises troughs and spikes that result from changing weather conditions, reducing the extent of intermittency. Thus, under appropriate conditions, unlike PV, a coal-solar hybrid is considered to be dispatchable.

Many thermal power plants often have a degree of flexibility in the amount and pressure of steam that can be integrated, so it should be possible for such variables to be optimised for the utilities' specific needs (Kho, 2012). Where legislation imposes limits on greenhouse gas emissions, hybridisation may offer a cheaper option to carbon capture and storage (CCS). This could also apply with other types of emissions.

Thus, depending on the particular circumstances, the main advantages cited for coal-solar hybridisation (EPRI, 2010b; Rajpaul, 2014; Roos, 2015; Appleyard, 2015; IT Power, 2012) are:

- the higher initial investment is balanced by reduced fuel consumption or increased power output;
- combining the two technologies allows 'greening' of existing coal-fired power assets;
- hybridisation can provide both dispatchable peaking and base load power to the grid at all times. CSP coupled with conventional thermal capacity (with or without thermal storage) can offer that capability;
- hybrid technologies could help meet renewable portfolio standards and CO_2 emissions reduction goals at a lower capital cost than deployment of stand-alone solar plants. Capex is less for the same capacity;
- siting solar technology at an existing fossil fuel plant site can shorten project development timelines and reduce transmission and interconnection costs;
- solar thermal augmentation can lower coal demand, reducing plant emissions and fuel costs per MWh generated;
- solar augmentation can boost plant output during times of peak demand. According to US studies carried out by EPRI, potentially, a solar trough system could provide 20% of the energy required for a steam cycle;
- hybridisation will reduce the level of coal and ash handling, reducing load on components such as fabric filters, pulverising mills, and ash crushers. It could also avoid the requirement to upgrade fabric filters or electrostatic precipitators (ESPs);
- solar input could provide some level of mitigation against difficult coal contracts, such as wet coal, fines, and variable coal quality;

- the majority of solar plant components could be sourced locally, helping boost local economies;
- rapid deployment – depending on size and configuration, hybrid plants could be completed in less than two years from notice to proceed;
- hybridisation could be used to extend the lifespan of existing thermal facilities – for example, where regulatory changes require a coal-fired plant to reduce emissions or face closure;
- hybridisation could avoid certain limitations and restrictions applied to new greenfield site projects; and
- hybrid plants will benefit from the general cost reductions that CSP technology is achieving. Many of these will also be directly applicable to hybrid plants.

3.3 Disadvantages of coal-solar hybridisation

Although coal-solar hybridisation can provide some benefits, there are obvious criteria that must be met (Stancich, 2010; Rajpaul, 2014):

- the location must receive good solar intensity for extended periods, both on a daily and yearly basis. This is not always the case (Figure 5);
- a suitable area of land close to the existing thermal power plant is required. It must meet certain criteria in terms of hectares available, topography, and issues such as shading;
- the land will no longer be available for other purposes such as agriculture;
- a solar add-on will require capital investment;
- there will be additional costs for operation and maintenance of the solar component, such as mirror washing; and
- the scale of most coal-solar hybrid projects has so far been low, mainly because these have been retrofits at existing coal-fired plants. Practical issues have tended to limit the solar contribution to ~5%. A new power plant, designed and built based on the hybrid concept from the outset, could possibly accommodate up to 30–40% solar share.

Each potential project brings its own combination of advantages and disadvantages. Although there are certain areas that will be common to all, there are various factors that will be specific to each individual site – projects need to be examined on a site-by-site basis. For example, limitations on the uptake of CSP-based systems in India have included a lack of local manufacturing base, plus competition from PV. Furthermore, adequate land is not always available – areas required can be considerable. For example, Adani recently built India's largest solar PV plant at Ramanathapuram in Tamil Nadu. At full power, this has a capacity of 648 MW and is claimed to be capable of powering 150,000 homes. The Ramanathapuram project required 10 km^2 of land. However, issues of limited land availability for some PV systems have been reported (Barnes, 2017).

There are factors that work in the favour of PV in India: some project developers and investors are more comfortable with PV as it has lower capex, the system is more familiar, PV is sometimes claimed to be less influenced by the presence of aerosols and clouds, water requirement is less for PV than that for CSP, and PV has a shorter gestation period (CSE, 2015). In other countries, a different set of criteria may apply.

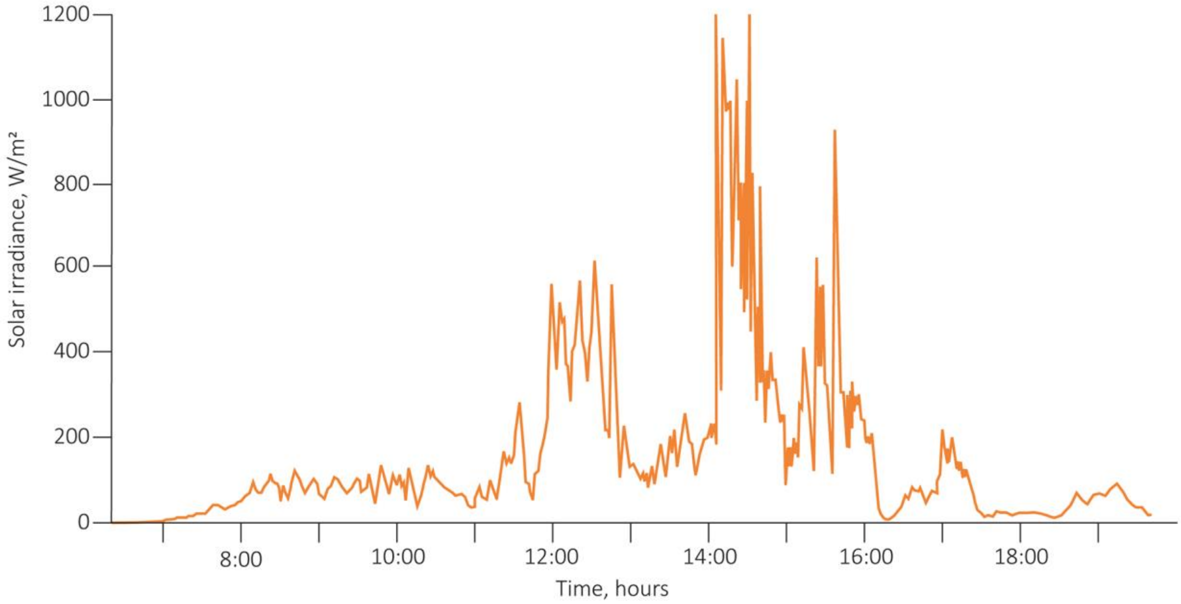

Figure 5 Example of daily solar irradiance fluctuation in Maryland, USA (Stone and Geyer, 2017)

Some requirements may be specific to retrofit situations. With an existing plant, the appropriate scaling of the coal- and solar-based systems is an important consideration; for example, if the existing steam turbine is sized to accept the full amount of solar steam while the coal plant is also operating on full load, the system pressure will tend to fall when the solar steam is not available. As a result, the efficiency in coal-based operation will be penalised. Conversely, if the steam turbine swallowing capacity (a measure of the volumetric capacity to accept a steam flow, usually referred to as the maximum possible steam flow at nominal pressure and temperature) is not specifically optimised, when the solar portion is on full load, the coal part of the plant will be forced to go in a very low part load. This situation may apply to certain CSP add-ons to existing coal plants, where the steam turbine was not designed to accept additional steam, in this case, from the solar part of the plant. However, such issues would probably be avoidable with a new-build hybrid, where integration and control can be fully incorporated at the design stage.

4 Thermal storage

The addition of a thermal storage system, used to store excess solar heat harvested during daylight hours, can be important for solar thermal power generation. When demand dictates, heat can be reclaimed and used to raise steam. This is a major advantage over PV-based generation as it is easier to store large amounts of heat than electricity. The ability to reclaim heat at night means that electricity from a plant incorporating thermal storage can usually be considered dispatchable, whereas that from a PV plant is not. In recent years, a growing number of thermal solar power plants have incorporated thermal storage, lengthening their hours of operation. The technology also holds potential for coal-solar hybrids. Extending operating hours in this manner will increase the capital costs of a project. However, it greatly decreases the cost of electricity produced from stand-alone CSP plants or coal-solar hybrids (Appleyard, 2015). Plants with thermal storage can operate in conditions nearer to base load; plant stop-starts can be reduced, minimising negative impacts on steam turbines and other major plant systems. As the technology is developed further, some providers expect a trend towards larger storage capacities.

Not all coal-solar hybrids would necessarily opt to include thermal storage. The main reason for its addition is to increase the capacity factor, increasing the utilisation of the power plant and thereby improving the overall economics. Usually, around half of the cost of a stand-alone CSP plant comes from the power island, with the balance from the solar equipment. In a hybrid plant, the power block is shared with the coal-fired portion and is therefore already available. Consequently, there may be less incentive to add thermal storage to a hybrid. However, adding storage can increase the utilisation of the solar portion, making it easier to control and improving the plant's reliability. The viability of a coal-solar hybrid will be influenced by numerous site-specific factors, and the addition of thermal storage is likely to depend on the specific project conditions and economics.

For thermal storage, the use of molten salts with tank storage has become the preferred choice. This is now considered to be a mature, commercially available technology. There are a growing number of plants that incorporate molten salt energy storage (MSES). Various combinations of salts can be used; for example, 60% sodium nitrate with 40% potassium nitrate – this has a melting point of 220°C. These materials are readily available, safe to use, and have significant heat retention characteristics – in practice, molten salts reportedly lose only 7% of their stored energy overnight. It is claimed that under the appropriate conditions, newer plants featuring thermal storage could approach 24-hour operation (Lo, 2014).

Large capacity commercially available types are currently limited to two-tank molten salt systems – the first large unit was demonstrated in 1996. They comprise two tanks filled with molten salts at different temperatures and fill levels. There are two major types available, namely direct and indirect. In the direct system, the salt is at the same temperature as the heat transfer fluid and storage medium. In the indirect system, thermal storage is decoupled from the heat transfer loop of the solar receiver via a heat exchanger; the first commercial scale system of this type came on line in 2009. In practice, both types have similar thermal capacities. However, the mass of salt of the direct system is less. This is because the capacity of the system is proportional to the temperature difference between the hot and cold tanks. Thus, the low temperature difference between the two tanks results in a larger thermal storage capacity (Bauer and others, 2012).

Various avenues are being explored with a view to improving the performance of thermal storage systems or reducing their associated costs. For example, in the USA, Babcock & Wilcox has partnered with eSolar (a supplier of large-scale solar power tower systems) to design, build, and test a modular base load molten salt power plant for use with CSP systems. The project received US$10.8 million in funding from the US DOE. A reference plant design has been completed using a molten salt-based thermal storage system that can be scaled to meet different requirements. The design is based on a 50 MWth module comprising a tower-mounted molten salt receiver surrounded by a solar field using eSolar's heliostat technology. Reportedly, this basic thermal module can be replicated without scaling or redesign, as many times as required, allowing plant sizes from 50 to 200 MW, with capacity factors ranging from 20% to 75% (Tynera, 2014).

Examples of major CSP plants using molten salt storage include the 20 MWe Gemasolar plant in Spain (claimed to be the world's first 'near base-load' CSP plant), and the 200 MWe Andasol plant (also in Spain), where up to 8 hours full-load generation is possible. In the USA, CSP plants with storage include Arizona's 280 MWe Solana plant (Figure 6), and Nevada's 110 MWe Crescent Dunes plant which claims 10-hours heat storage capability. Elsewhere, other projects are proposed or in development. For example, in South Africa, three solar projects feature thermal storage:

- KaXu Solar One – this has an installed capacity of 100 MW and includes 2.5 hours of storage capacity;
- Khi Solar One – installed capacity of 50 MW with 2 hours of storage capacity; and
- Xina Solar One – installed capacity of 100 MW with 5 hours of storage capacity;

Molten salt storage was also slated for use at a proposed solar boost hybrid project at the Collinsville coal-fired power station in Queensland, Australia. However, this is no longer proceeding due to unfavourable economics.

Figure 6 Thermal storage tanks at the 280 MW Solana CSP plant in Arizona, USA (photograph courtesy of Abengoa Solar)

4.1 Possible future thermal storage developments

Historically, a number of different heat transfer media have been used, each with its own set of characteristics (Table 4). Recently, molten salt mixtures have been increasingly adopted.

Table 4 Characteristics of solar heat transfer fluids (Haines, 2012)

Medium	Pressure/ temperature	Heat capacity (kJ/g) with typical return temperature	Density (kg/m^3)	Limitations
Hot water	Up to 60 MPa/up to 290°C	1.164	730	High pressures needed to reach high temperatures. Large lines needed for practical pressure drop. Only practical to store heat at temperature up to just over 100°C
Low pressure steam	205 MPa/120–165°C	2.638	3.7	Can only transport over short distances due to pressure losses. No possibility to store heat
Medium pressure steam	20–50 MPa/200–600°C	3.538	12.7	Moderately high pressure needed for containment. No possibility to store heat
High pressure steam	100–200°C/300–600°C	3.412	55	Very high pressures require thick tubing. No possibility to store heat
Hot oil	5–10 MPa/up to 315°C for mineral and 400°C for synthetic oils	0.586	800	Expensive and slowly degrades at higher temperatures. Has to transfer heat to working fluid of power generation cycle. Can store heat but inventory is very expensive
Molten salts	5–10 MPa/up to 540°C	0.587	1680	Freeze at ~100–150°C. Has to transfer heat to working fluid of power cycle. Provides possibility of storing heat

Work is underway to develop innovative salt mixtures with lower melting temperatures or higher thermal stability. As part of this process, various aspects are being examined such as extending the thermal stability of salt mixtures, and assessment of corrosion in valves, pumps and solar collectors operating under realistic conditions (Bauer and others, 2012).

Although still largely at the R&D stage, there are several concepts based on molten salts that aim to reduce costs by using a single tank. This would need stratification with defined hot and cold temperature zones. Free convection within the tank would be undesirable and several techniques to suppress this have been proposed – for example, a floating barrier within the volume of the salt, or the addition of filler materials (so-called thermocline concept). An advantage of this system is that a proportion of the molten salt required could be replaced with inexpensive filler materials. Depending on the individual plant, the amount of salt needed can be significant. For example, the Andasol plant stores heat at 400°C – this requires 75 tonnes of salt per MW of heat. The storage system of the Gemasolar plant uses a total of 6250 tonnes of salt.

Possible alternatives continue to be researched. For example, the NEST-type thermal energy storage system has been developed by Norwegian company EnergyNest and proposed as a cost-effective option. This uses proprietary and patented technology and has been developed in collaboration with a global cement company. It relies on the use of a special type of concrete 'Heatcrete' with superior thermal performance. Independent testing has confirmed its suitability up to 600°C (Pedersen, (2013).

The NEST thermal storage system comprises a large number of individual elements, connected through pipes in series and parallel. A storage 'element' consists of Heatcrete with integrated heat exchanger tubes contained inside a steel casing. Multiple storage elements are placed inside a steel frame structure cassette for easy transport and assembly on site. Multiple cassettes can be connected together. The heat exchangers are claimed to allow for effective heat transfer with a range of different heat transfer fluids that include thermal oil, and water/steam, and can operate over a wide temperature range (from -50°C to 600°C). It utilises a sequential piping arrangement divided into storage zones with different temperature levels, enabling operational flexibility and efficiency. The system is scalable from <1 MWhth to >1000 MWhth. It is constructed from inexpensive and readily available materials such as concrete, aggregates and carbon steel, thus costs can be held down. It is claimed that for a nominal 1000 MWhth parabolic trough CSP plant, NEST technology would cost under 60% less than an equivalent molten salt system (Pederson, 2013).

Development of systems and components is continuing, sometimes via joint collaborations. For example, Babcock & Wilcox (B&W) is working with eSolar to develop an improved molten salt storage system. The venture is to design, build, and test a modular, base-load molten salt power plant based on CSP. B&W considers that the combination of CSP and molten salt technology has the potential to play a major role in helping meet the US' energy needs in a cost-effective, environmentally friendly way. Again, certain elements also hold potential for coal-solar hybrids.

4.2 Coal-solar hybrids – challenges to deployment

Various challenges remain for the large-scale deployment of coal-solar hybrid systems – these may be political, technical or financial. From a purely practical point of view, any solar-based power generation system needs a consistent source of sunlight of adequate intensity, and this clearly limits possible locations. Although arguably less important for PV systems, it is crucial for those based on solar thermal technology. Coal-solar hybrids require land close to the power plant for the solar collection system, possibly up to several thousand hectares. However, land immediately around a power plant is sometimes unattractive for other purposes, so may be readily available. A possible complication is that often, coal-fired plants are located near a source of water needed for cooling. This means that they are rarely located in arid high desert sites that are well suited to solar thermal applications.

Many potential coal-solar hybrids could find themselves competing against other types of power generation. Depending on the location, this could be other fossil fuel-fired capacity, nuclear power, or several forms of renewable energy such as PV. This competition will vary from country to country and is likely to be influenced by the makeup of the national energy mix and other local circumstances. From an economic standpoint, a hybrid must be able to show a price, and ideally, an environmental advantage in order to be considered viable.

An important challenge identified is to increase the solar share of a coal-solar hybrid. To date, the energy input from the solar component has been limited, largely as a consequence of their application to retrofit applications as opposed to new build. There is some consensus that the sector needs bigger hybrid projects based on highly efficient, newly built coal-fired plants – this would provide more scope for improved efficiency and better economics. Ideally, a new greenfield hybrid would be based on a modern supercritical or ultrasupercritical unit that featured optimal integration of the solar heat input into the process (Siros, 2014). In addition, the addition of thermal storage could improve dispatchability further and help minimise the cost of electricity (Appleyard, 2015).

While the concept of hybridised power plants has existed for some time, its application and hence, bank of operational experience, remains somewhat limited. Conventional thermal power plants and intermittent renewables such as solar power lie at different ends of the technological spectrum. Consequently, the combination of such disparate systems will inevitably throw up technical issues. The current 'live' projects being developed will provide useful data and operational experience. Alongside economic issues, as every project is essentially unique, each will bring its own combination of technological issues that have to be resolved. These will include integrating the system, controlling the coal versus solar component, and dealing with the usual engineering challenges associated with plant construction. If based on an existing power plant, some issues will be associated with retrofitting of the CSP system; a new build plant may have different challenges, although some issues are likely to be common to both. Historically, integrating the (albeit limited) number of coal-solar hybrid projects has not thrown up any insurmountable problems – it has mainly been a matter of where best to integrate the steam into the existing system, something that most utilities are comfortable with. In principal, a new plant would probably be easier to develop as integrating both systems could be addressed at the design stage.

Where solar power was combined with a coal plant using more advanced ultrasupercritical steam conditions, it is likely that some new components would require development – for example, a solar recovery steam generator with matching steam conditions. However, this may not be economic, and the option always remains to integrate the solar steam at the IP steam turbine (Appleyard, 2015). Where solar power was integrated with a modern conventional coal-fired power plant operating under supercritical conditions, in order to maximise efficiency, reheat would be applied and the unit would recuperate heat for feedwater heating and air preheating. The introduction of additional heat from a CSP system could impact on this heat integration and would need to be taken into account at the plant design stage.

Other potential technical hurdles include monitoring the effectiveness of directly circulating water/steam through the solar field (particularly as water quality is crucial with once-through boilers), and where solar energy is used to generate main or intermediate pressure steam, that any imbalances between the exchangers of the boiler are accommodated – it is likely that some issues would need confirmation from the boiler manufacturer on a case-by-case basis (Roos, 2015; Siros, 2014).

It appears that any outstanding technical problems associated with hybridisation can be overcome. However, depending on the individual circumstances, the biggest issue may simply be economic viability. In some locations, hybrids may have to compete directly with other forms of power generation such as natural gas-fired plants. At the moment, gas prices in some parts of the world remain low, and this will undoubtedly make investment in hybrids more uncertain (Miser, 2016). However, there are situations where alternatives are much more limited and here, coal-solar hybrids could find useful niche markets.

5 Prospects for coal-solar hybridisation

Many factors can impact on the feasibility of a hybrid project, some local and others more related to coal use in general.

To be viable, a project must meet various criteria such as adequate consistent levels of sunshine. A prospective host coal-fired power plant must be of adequate efficiency and have a reasonably long operational lifetime remaining, and also have sufficient land close by for solar collection system. Project funding may also be an issue. However, combining solar power with an existing coal plant can help reduce overall environmental impact and increase plant efficiency. Where conditions are suitable and there is the political will, combining these two disparate technologies may offer a route forward that in some situations, could allow coal to continue contributing to the energy mix through the provision of reliable low-cost electricity, but with lower environmental impact.

To date, much of the focus has been on the addition of solar power to existing coal-fired capacity. However, industry opinion, such as that of the supplier of solar-based technology **Abengoa,** is that the biggest potential lies with more efficient new-build projects and that these are likely to represent the main share of the market. In the near term, greenfield plants are more likely to be installed in emerging countries where additional power generation is needed. Abengoa considers that the retrofit market is limited as potential sites are restricted to those with adequate sunshine and available land.

Abengoa has been engaged in the solar power sector for some years and has been involved with a number of major CSP projects. The company supplied technology to Xcel Energy's coal-solar hybrid Cameo Generating Station in the USA, the first to integrate an industrial solar installation into a conventional coal-fired power plant. There has also been involvement with major CSP projects in South Africa and Chile. The Chilean project is located in the Atacama Desert, the region with the highest solar radiation concentrations in the world. It will be the first coal-solar hybrid plant for direct electricity production in South America, producing 110 MW via tower technology. The improved thermal molten salt thermal storage system is expected to provide up to 17.5 hours of operation, allowing the power plant to operate for 24-hours a day. Abengoa feel that this will be helpful in replicating the technology elsewhere.

Although considered suitable for retrofit situations, **Alstom Power** (now part of General Electric) is also of the opinion that the full potential of the technology can best be exploited where it forms part of a modern new-build power plant (Appleyard, 2015). The company has proposed a retrofit solar feedwater heating integration system based on central receiver tower technology. This can operate in either fuel save or boost mode and is applicable to both coal- and gas-fired plants. The company considers that the market for such hybrid systems is likely to gain momentum in the mid-term (Pécresse, 2013).

In the area of solar thermal power generation, **GE** suggests that plant operations are best coupled with a molten salt storage system, considered as essential in meeting the need for flexible power generation.

There is some consensus that in order to make best use of hybridisation, the technology needs to be demonstrated on new and larger coal-fired power plants. Thus, solar engineering company **Flagsol GmbH** believes that a large coal-fired power plant would be capable of absorbing between 200 and 400 MW of solar thermal power. This would significantly increase plant efficiency and reduce environmental impact (Fairley, 2009).

Siemens considers that the target areas for natural gas-CSP hybrids will include the Middle East, North Africa, Mexico, parts of the southwestern USA, and China, whereas the potential market for coal-solar units will mainly be in South Africa, India and Australia, countries with significant indigenous coal reserves and high levels of solar radiation, but only limited access to natural gas (Zindel, 2012).

There are also possibilities for combining solar thermal technology with power plants cofiring coal and biomass – this would add a second form of renewable energy and help reduce further the plant's environmental footprint. In Finland, **VTT** has been examining this concept as a possible cost-effective route to reducing conventional plant emissions and CO_2 (Bioruukki, 2016). VTT is developing a system for integrating solar power into a conventional boiler. The concept is also under consideration in India where there is a proposal for a 100–150 MW demonstration plant combining solar power with biomass. There is also the possibility of combining solar power with an Indian plant cofiring biomass and coal.

Industry opinion suggests that there could be a significant market for coal-solar hybrids. For example, major supplier of solar-related equipment **Areva Solar** suggests that hybridisation offers an opportunity to install the lowest cost form of solar power. When comparing the cost of similarly sized stand-alone PV plant with a coal-solar booster, the latter is invariably cheaper, partially because much of the infrastructure and systems needed are provided by the existing power plant. Locating a solar collection system at an existing power plant site also speeds the time to market: it typically takes nine months to a year to bring on stream (Kho, 2012). Although potential locations for coal-solar hybrids are limited, Areva believes that a significant number of sites have potential. The company considers that the market is big enough to accommodate both PV- and CSP-based technologies. However, they do not foresee a large switch in the immediate future. In the longer term, CSP-based hybrids may be considered a better option as they would overcome many of the grid, intermittency and transmission issues that can limit input from PV systems (Kho, 2012).

Further development of CSP-related equipment continues with various major manufacturers pursuing options to increase the efficiency and reduce costs. For example, **Mitsubishi-Hitachi Power Systems (MHPS)** considers that CSP has advantages over PV generation, such as less fluctuation in output relative to variations in solar radiation intensity, and stable power supply even under cloudy or night time conditions (as thermal energy can be collected and stored). The company has developed and is now testing and demonstrating a novel hybrid system that combines CSP with an inexpensive low-temperature Fresnel evaporator; this uses 150 mirrors, an evaporator and a superheater, built into a central tower. Around 70% of the sunlight that reaches the plant is captured and directed to the evaporator. This is used to generate steam at 300°C that is transferred to a superheater housed in the top of the tower. Using concentrated sunlight, steam temperature is increased further to 550°C. Cost reductions are achieved as the steam is already pre-heated before it reaches the top of the tower. Thus, fewer mirrors are required to achieve the maximum temperature. According to MHPS, this new system can generate electricity much more cheaply. The test facility is operating under the control of the Ministry of Environment of Japan. In addition, starting late 2016, MHPS began testing a high-temperature thermal energy storage system (Luleva, 2016). Although efforts are directed primarily towards stand-alone CSP operations, developments such as these also have the potential to drive down capital and operating costs of coal-solar hybrids.

Part of MHPS (previously known as **Hitachi Power Africa**) was involved in case studies that examined the potential of coal-solar hybridisation at two of Eskom's newer coal-fired power plants, Mendupi and Kusile. These considered a number of possible hybridisation options. In the case of Mendupi, it was concluded that operating the power plant continuously during hybrid CSP operation would reduce coal consumption and consequently, CO_2 emissions. Fresnel technology for high-pressure heater bypass was considered the most economically viable option (Hoffmeister and Bergins, 2012). The results showed that, depending on the scenario, the steam generator load during hybrid operation could be reduced considerably, resulting in a CO_2 reduction of between 75 and 81 kt/y for each unit (Costella, 2012).

Although **Siemens AG** concentrates more on solar-gas systems, in principal, much of their technology is also applicable to coal-solar hybrids. The company offers a power block that encompasses all components for the entire water/steam cycle in parabolic trough, central tower, linear Fresnel CSP plants, and hybrid coal-solar plants. In addition to the steam turbine generator, this can also include other plant components such as condensing systems to preheaters, cooling, plus electrical equipment, control systems, and instrumentation. Siemens suggests the adoption of a reference plant design approach in the provision of CSP power block solutions. Their pre-engineered design integrates the power block, solar field, and heat transfer fluid system into an optimised configuration. Various permutations of the Siemens design are possible, as well as different combinations of CSP with coal, oil or biomass (Zindel, 2012).

5.1 Future technology developments

As with any generating technology, a system based on solar energy needs to make economic sense. Thus, it is important to keep capital and operating costs at an acceptable level. Although much recent focus has been on stand-alone CSP systems, many cost reductions achieved will also have a positive impact where they form part of a coal-solar hybrid. The opportunities for reducing the cost of CSP plant are encouraging (IRENA, 2012). The commercial deployment of CSP is still at a relatively early stage, and as technology development proceeds and plants increase in size, costs are likely to fall as components benefit from mass production and increased competition between vendors.

Thus, efforts continue to reduce system costs, increase the efficiency of solar energy-to-electricity conversion, and minimise environmental footprint. Further refinement and research is gradually improving plant components and systems. Several key areas have been identified where cost reduction would be particularly beneficial:

- the solar field – cost reduction via improved designs, mass production, and cheaper components should help drive costs down;
- the heat transfer fluid – newly developed fluids and those capable of operating at higher temperatures will help to improve storage possibilities and reduce costs;
- thermal storage system – linked closely with the HTF. Higher temperatures, especially from solar towers, should reduce the cost of thermal storage; and
- the power block – although there remains some scope for cost reductions, these will be more modest than for the other parts of the system.

Improvements in heat transfer and thermal storage capabilities will be particularly important. Improved heat transfer fluids would provide higher operating temperatures, allowing increased electrical efficiency for CSP and hybrid plants, achieving higher thermal-to-electric efficiencies. It would also help reduce the cost of thermal storage. Historically, most commercial plants have relied on various forms of synthetic oil as HTF. However, these are generally expensive and have a maximum operating temperature of less than 400°C. Molten salts that can increase operating temperature up to ~550°C or more, leading to improved thermal storage performance. Potentially, solar tower-based systems could increase temperatures even further, possibly up to 600–700°C. This would be compatible with commercial ultrasupercritical steam cycles that would allow the Rankine cycle efficiency to increase to 48%, compared with ~42–43% for today's designs (IRENA, 2012). Supercritical CO_2 is also being explored as HTF to enable higher operating temperatures.

5.1.1 Solar boost on coal-/biomass-fired power plants

Adding a solar booster to an existing coal-based plant previously modified to cofire biomass could be useful as the solar heat would help offset the output and efficiency penalty resulting from the lower heating value of the biomass (IEA Solar, 2014). Such a combination would effectively combine two renewable forms of energy with coal-based power generation. VTT in Finland and several other organisations are exploring coal-solar-biomass concepts.

Work is also underway in Denmark, where Aalborg CSP has been selected to design and deliver a CSP system to be integrated with a biomass fueled district heating plant (operated by Brønderslev Forsyning) for combined heat and power generation. This is claimed to be the first large-scale demonstration of such an integrated energy system.

Aalborg has completed a feasibility study on the potential of using CSP as an add-on to the biomass plant and is also supplying the required 16.6 MWth CSP unit. This will consist of 40 rows of parabolic trough loops, optimised for Nordic climate conditions. These will harvest solar energy, warming a heat transfer fluid to 330°C. Steam raised will be fed through a turbine to generate electricity, although the system will also be capable of producing lower temperatures suited to district heating purposes.

5.1.2 Solar particle receivers (SPR)

In most CSP-based plants, heat harvested from the solar collection system is generally transferred via a heat transfer medium. An alternative currently under development is the SPR – these are expected to increase CSP plant operating temperatures, enabling them to support higher efficiency power conversion cycles. They have the potential for application to stand-alone CSP plants as well as coal-solar hybrids.

The high temperature SPR system uses solid particles as both heat transfer and energy storage medium. As the particles are extremely heat resistant and robust, the particle receiver system can absorb very high solar flux densities without the drawbacks associated with metal tube receivers. In operation, high efficiencies can be achieved and problems such as hotspots, thermal stresses, and thermal fatigue avoided (Zhu, 2015). In operation, the solid heat transfer material is heated to >800°C, well above the operating temperatures of molten salt storage systems. The solid particles also help overcome some of the other challenges associated with molten salt systems such as freezing, instability, and degradation. The higher operating temperatures plus the use of low cost heat transfer medium should boost power cycle efficiency, helping reduce costs of CSP or hybrid systems.

Studies suggest that there is considerable potential for SPR technology. For example, Prosin and others examined the thermodynamics of a coal-solar hybrid plant with feedwater or turbine bleed steam heating using solar heat. It was claimed that using SPR technology for preheating air in this manner had the potential to increase considerably the solar share of the energy input, enabling higher solar-to-electric conversion efficiency (Prosin and others, 2014, 2015).

In the USA, Babcock & Wilcox Power Generation Group is collaborating with the NREL to develop a high temperature SPR. The use of low cost, stable heat transfer medium, innovative component design, and increased cycle efficiency is expected to help reduce CSP component and system costs to below those of comparable state-of-the-art molten salt-based plants. As part of the programme, B&W and NREL are examining the inclusion of a fluidised bed heat exchanger and its integration with various power cycles. The SPR technology could provide a possible route to achieving a LCOE target of 0.06 US$/kWh as set by the US DOE *SunShot* initiative.

In operation, a heliostat field focuses the sun's energy onto the SPR where it is absorbed by the flowing solid medium. The hot particles exiting the SPR are then transported to the thermal energy storage system, consisting of one or more hot and cold particle storage silos. The hot particles are dispatched to the fluidised bed heat exchanger where energy is transferred from the hot solids to the working fluid to produce steam, fed to a steam turbine. After energy has been extracted from the particles, they are sent back to the cold particle storage silo. The stored cold particles are then conveyed back to the SPR when they are re-heated by solar radiation in readiness for the next cycle (Sakadjiana and others, 2015). A 'cascading' SPR is being developed, based around a series of tubular shaped mini cavities. This allows the particles to contact the heating surface that receives the solar radiation. Solar energy is directed to the internal surfaces of these, whilst particles flow over their outer faces. The design is based on near-black body radiation principles and offers the potential to produce high temperature particles whilst maintaining desirable receiver efficiencies of 90% or higher. The system raises the particle temperature via indirect heat exchange.

A similar concept has been proposed in Australia, where studies have examined the potential of preheating boiler combustion air with a novel high temperature concentrating solar thermal system using an SPR known as the 'CentRec 'system. This novel method of preheating is claimed to have the potential to increase the solar share of the overall system, improve fuel saving, and produce a higher solar-to-electric conversion efficiency. It should generate a higher operating temperature and allow for integrated thermal storage. Analysis suggests that preheating combustion air in this manner could result in significantly higher solar-to-electric conversion efficiency, compared to existing hybridisation options. Air preheating enhances boiler efficiency by reducing stack losses. The proposed design has been modelled and compared with a Fresnel-based system; the LCOE produced using the SPR design was calculated to be ~59% of that produced by the Fresnel-based system.

The Centrec system uses heat resistant ceramic particles as the heat transfer medium to directly absorb incident solar radiation. During operation, solar radiation is focused from heliostats onto the particle receiver located at the top of a tower. The unit has a rotating cylindrical cavity – the resultant centripetal force on the particles causes them to form a covering layer on the internal receiver wall. Varying the rotation speed allows control of the particle flow rate and allows adaptation of the mass flow to actual solar power input, ensuring a high constant outlet temperature.

Once heated, particles are transported to an insulated high temperature storage vessel where they are used directly as the thermal storage medium. Combustion air is heated in a counter-current moving-bed direct contact heat exchanger. Air is blown through the hot particles as they are transferred to a second storage vessel for low temperature storage. Efficient heat transfer can be achieved as the particle flow has a large surface area. After the particles have cooled, they are transported back to the receiver at the top of the tower using a lift system. The cycle then repeats.

The Centrec system was modelled and compared with a typical 750 MW SC power plant with reheat and steam cycle parameters of 250°C/6 MPa and 540°C/560°C. Due to the increased system operation efficiency plus the addition of low-cost thermal storage provided by solar towers, significant fuel savings could be made (~8%/y using SPR heating at 540°C is claimed). When operated at up to 950°C, an estimated 20% of the annual fuel use could be saved (Prosin and others, 2015).

5.1.3 Solar power-coal gasification hybrids

The possibility of combining solar thermal energy with coal gasification has been proposed with solar heat being used to generate steam to supply the gasification process. Using solar energy provided by power towers to provide heat for the gasification process could create an intermediate solution that reduces CO_2 emissions whilst maintaining power generation capacity. Estimates of energy balance indicate that producing the stoichiometric amount of steam required for the gasification reaction from solar energy could reduce the energy required for gasification by 29% (Flannery and Desai, 2014). As with most other solar-based applications, a good supply of solar radiation would be a prerequisite.

5.1.4 Integration of solar energy technologies with CCS-equipped plants

The possibility of using solar energy to meet some of the energy requirements imposed by the addition of carbon capture and storage (CCS) systems to coal-fired power plants was examined by the IEA Greenhouse Gas R&D Programme (Haines, 2012). The study considered several possible options for using solar energy to overcome some of the parasitic losses incurred by post-combustion CO_2 capture processes.

The most promising combination was the use of solar energy for capture solvent regeneration and other power plant heating duties. The amount of energy that could potentially be collected in proximity to a 1 GW power plant sited in a typical location was considered. Such locations are more likely to be in temperate climates where levels of solar radiation are lower than those at desert sites, often favoured for CSP applications. For reasons of efficiency, the distance of the solar collection system from the power plant was limited to a maximum of 2 km. The preferred method for incorporating harvested solar energy was direct steam generation using linear Fresnel arrays. Medium pressure steam was the preferred condition for transport.

It was concluded that at peak radiation times on sunny days in a temperate climate, it would be possible to harvest sufficient energy to defray all of the CCS losses as well as contribute towards several internal low temperature feedwater heating duties. However, over a 24-hour period, only part of the parasitic losses could be covered. The net result was that plant fossil fuel efficiency could be improved by up to 3%. Thermal storage would be necessary in order to achieve higher levels.

It was considered inadvisable to use the solar-generated steam to reduce the amount extracted from the main turbine as this could affect overall efficiency. Ideally, a separate dedicated steam turbine would be used, with steam from the main plant used for start-up and to maintain hot standby where appropriate. The turbine could also be used should the power plant wish to operate for a period without CO_2 capture. This could provide a significant financial incentive at times of peak demand or price, and would also enable plant efficiency to be maintained if the capture plant was taken out of service.

Heat losses would be significant as the system would cool overnight – it would be uneconomic to keep the solar array warm. Thus, the role of the host CCS plant would be limited to managing the warm-up and standby of the solar turbine. This would provide an opportunity for CO_2 capture to be interrupted at times of high power demand without loss of thermal efficiency, as it could be used for efficient conversion of extracted steam, leaving the main turbines operating at maximum efficiency. The legacy left by the CCS plant would be a small but effective solar power plant that would be capable of stand-alone operation with little modification (Haines, 2012).

In other studies, Brodrick and others (2015) considered the optimisation of CCS-enabled coal-solar power generation. This work examined the optimal design and time-varying operations of a CO_2 system retrofitted to a coal-fired power plant. The capture technology was an amine-based temperature-swing absorption system (ABTSA), considered to be one of the most mature CCS technologies, to which process steam was supplied from an auxiliary unit. One of the candidate auxiliary heat sources explored was solar thermal energy. An ABTSA system requires considerable capital investment and a significant amount of low-temperature steam for the desorption of CO_2 (~3.6 MJ/t CO_2). This steam can be extracted from the power plant itself, or be provided by an adjacent auxiliary system. The latter was considered to have several advantages such as the avoidance of reductions in the base-plant electricity output that could range between 24% and 40% of plant capacity. It was concluded that without a high carbon tax, the direct use of a solar thermal system for power generation was a more profitable option.

5.2 Coal-solar activities and projects

In the following section, coal-solar hybridisation activities undertaken, proposed or underway are reviewed on a regional or country basis.

5.2.1 USA

Historically, the Electric Power Research Institute (EPRI) has been the main focus for utility-scale coal-solar integration. In 2012, estimates produced by EPRI and NREL suggested that there was significant potential for solar augmentation within the existing thermal power fleet, both coal- and gas-fired. A total of 21 GW across sixteen states was suggested, with the most promising sites in the southwest of the country. However, at least one good site was identified in each state (Libby, 2012). In the following years, there have been several proposed projects based on existing coal-fired power plants although for a variety of reasons, only one has progressed to commercial operation.

Cameo Generating Station, Colorado – The Colorado Integrated Solar Project (CISP)

The world's first hybrid coal-solar hybrid power plant was developed near Palisade in Colorado. It was undertaken as part of the state's Innovative Clean Technology Program, an initiative designed to test promising new technologies that had the potential to reduce greenhouse gas emissions and produce other environmental improvements.

Xcel Energy and Abengoa Solar partnered on this US$4.5 million demonstration that used sun-tracking parabolic trough technology to supplement the use of coal. The system was put into operation in 2010. The main aim was to demonstrate the potential for integrating solar power into large scale coal-fired power plants in order to increase plant efficiency, reduce the amount of coal required and hence, reduce conventional plant emissions and CO_2, and to test the commercial viability of combining the two technologies. Abengoa provided the solar-related technology that included a 2.6 hectare solar field housing eight rows of 150-m long solar troughs (Figures 7 and 8). Heat generated was focused on a heat exchanger where it was used to preheat feedwater supplied to one of the Cameo plant's two 49 MW coal-fired units (Unit 2) (Mills, 2011).

Figure 7 Solar collection system at the Cameo Generating Station (photograph courtesy of Xcel Energy)

Figure 8 Abengoa Solar sun-tracking parabolic trough technology at Cameo Generating Station (photograph courtesy of Xcel Energy)

Unit 2 consisted of a 2-pressure steam turbine, two low pressure feedwater heaters, a deaerator, and two high pressure feedwater heaters. The solar powered heat exchanger provided additional feedwater heating, fed in between the two high-pressure feedwater heaters.

In operation, the parabolic trough arrangement concentrated solar radiation onto a line of receiver heat collecting elements (HCE) filled with HTF. The HTF used was Xceltherm 600, a blend of two refined white mineral oils, designed to maintain thermal stability at sustained operating temperatures up to 315°C. The solar energy heated this to ~300°C after which it was fed to a heat exchanger where the heat was transferred to water, heating it to ~200°C prior to being fed to the boiler. The cooled HTF was then cycled back through the pump to repeat its circuit through the solar field. The system consisted of a closed thermal circuit that enabled heat exchange between the solar-heated HTF. Main system components comprised a heat transfer fluid pump and piping, the solar field, a solar heat exchanger, an expansion vessel, and a nitrogen system. The CSP was rated at 2 MWe (generation 49 GWh).

In 2010, the Cameo plant undertook a 7-month pilot/demonstration programme after which the station was retired and the CSP plant decommissioned. Overall, the results were considered positive. The addition of solar energy increased overall plant efficiency by >1%. During the test period, coal demand and air emissions were reduced (~600 tCO_2, >900 kg NOx, and 2450 kg SO_2). The installation confirmed that this type of supplemental application to an existing fossil fuel-fired boiler was feasible and would not interfere with normal generation operations.

During the test period, there were no coal unit outages or derates caused by the CSP system. Unit 2's availability was 98.4%. The only downside was the power needed for operation of the CSP system – this was ~0.4% of the equivalent kWh output, used mostly by the HTF pump.

Although coal demand and emissions were reduced, actual reductions were less than expected. This was attributed largely to the small scale of the project. Furthermore, the limited remaining lifetime of the power plant meant that some aspects of the project were not developed with long term operation in mind. For example, to minimise costs, less insulation was used than would have been installed for a 20-year design. Also, in order to minimise O&M expenditure, mirror washing was less frequent than recommended.

At the completion of the project, integration and operation of the solar system with the existing coal-fired unit was deemed a success. However, at the time, the situation regarding costs and efficiencies was less clear and the plant operator felt unable to make any definitive recommendations regarding further future deployment at any of its other power plants (Public Service Company of Colorado, 2011). Although not revealed, it was concluded that at the time, on an equivalent MWh basis, the cost of the hybrid was significantly higher than wind or solar PV. However, the company has since noted that the technology has been further developed and that associated costs are likely to have fallen. Since the Cameo project was completed, costs for solar equipment in general have reduced but there do not appear to be any plans for any further coal-solar hybrids in the immediate future.

Tri-State's Escalante Station, Prewitt, New Mexico

Tri-State Generation and Transmission Association's Escalante plant normally operates on base load and provides ~220 MW output to the grid plus a nominal 56,700 kg/h of cold reheat steam to a reboiler that generates low pressure steam for an adjacent paper mill. Extraction steam is supplied to the mill on an interruptible basis.

EPRI developed a conceptual design for the Escalante plant to investigate and optimise integrated solar designs within equipment limitations, operational requirements, and reliability constraints. In 2009, Tri-State entered into an agreement with EPRI to host a case study that was intended to aid electric utilities add solar energy to existing coal-fired power plants. It considered both coal saving and solar boost modes of operation. A conceptual design and options for retrofitting the existing power plant were developed (Reliable Plant, 2009).

The project focused on the possible development, construction and integration of a 36 MWe solar field into the existing station's systems. The detailed engineering phase of the project began in 2011 and considered various possible solar options that comprised parabolic trough, central receiver, and linear Fresnel solar collector systems. In addition to providing steam for the power cycle, the possibility of the solar field also supplying the adjacent paper mill load, thus restoring plant generation capacity, was examined.

The Escalante study selected parabolic trough technology with synthetic oil as HTF. Whenever available, solar input would first be used to satisfy the requirement for exporting steam to the paper mill. Any excess would then fed into the plant's Rankine cycle. Several different integration options were considered that examined the production of high pressure steam fed into the plant's cold reheat system, or used for feedwater heating.

All the options modelled were required to meet the specific requirements of the site, limitations of the selected solar technology, constraints of the existing plant equipment, operational modes of the Escalante Station, and the steam export obligation to the paper mill. During normal plant operation, steam exported to the mill is produced using cold reheat steam taken from the power cycle, reducing electricity output. The addition of solar power was intended to compensate for this power loss. The option of producing slightly superheated HP steam proved to be the most promising concept. It was determined that the solar field would be capable of providing a maximum solar input of 96 MWth (equating to ~36 MWe). This would require more than 150,000 m^2 of reflective surface. The field would be operable when direct normal solar radiation in the plane of the collectors was ~300 W/m^2 or greater. Thermal storage did not form part of the study, thus the solar steam plant would start-up and shut-down on a daily basis. Various ways of accommodating the weather-dependent variable input from the solar field were considered (Libby and others, 2010).

It was anticipated that a successful outcome would advance the understanding of solar thermal technology development and hybrid project design. However, the project did not proceed to actual construction (EPRI, 2010a).

Mayo Plant, Roxboro, North Carolina

The 727 MW pulverised coal fired Mayo power plant in North Carolina was the subject of technology and economic feasibility studies carried out by EPRI, aimed at integrating solar thermal energy with existing coal and natural gas power plants.

Despite the potential cost savings of hybridisation, it was concluded that the level of solar intensity available limited the economic viability of utility-scale CSP technologies in general for this region (Duke Energy, nd).

Wilson Sundt Generating Station, Tucson

The most recent US project was the addition of solar power to a conventional dual-fuelled (coal and gas) thermal unit at Tucson Electric Power's (TEP) H. Wilson Sundt Generating Station in Arizona – the *Sundt Solar Boost Project*. In 2012, TEP and AREVA became partners in the project, with AREVA supplying the

CSP-related equipment and CLFR solar steam generators. The system used >500 steel mirrors, each 23 metres long (AREVA, 2016).

At full output, solar contribution produced up to 5 MW of electricity without increasing plant emissions. This avoided the combustion of 1.3 million m^3 of natural gas or 3600 t/y of coal (AREVA, 2012). If the plant operated solely on gas, CO_2 emissions were reduced by 4600 t CO_2/y. When running on coal, the figure was 8500 t CO_2/y. Output from the project helped TEP meet Arizona's Renewable Energy Standard requiring electric utilities to increase their use of renewable energy each year until it accounts for 15% of their power by 2025.

Project construction began in April 2014. The total cost, which qualified for federal tax credits and renewable energy subsidies, was kept confidential although some sources suggest ~US$7.8 million. Once operational, the multi-fuelled Unit 4 fired either coal or natural gas, supplemented by landfill gas and input from the solar plant. However, TEC recently announced that the use of coal at the plant would come to an end largely to avoid the addition of further expensive emission control systems. The low price of natural gas was also a major factor. Unit 4 will now use gas as its main fuel along with landfill gas and the solar boost system (TEP, 2016).

5.2.2 Australia

In recent years, the potential for CSP in Australia was examined. It was concluded that it was technically feasible to add up to 15 GW or more of CSP capacity, with only modest grid extensions. As part of this, the use of coal-solar hybridisation and its potential for large-scale grid-connected systems was considered. The technology was identified as a potentially important near-term application. It offered lower costs than stand-alone CSP plants, and possible lifetime extension of existing power plants where coal supply was limited or there were issues relating to air pollution limits. Additionally, process heat for major industries such as mining or steel showed potential for co-location. However, the main limitation was the need for adequate land close to the power plant for the solar array. For this reason, hybridisation was not suitable for reducing emissions from, for example, the lignite-fired Hazelwood power plant in Victoria.

In 2007, the Council of Australian Governments developed several technology roadmaps, one of which covered high temperature solar thermal (HTST) technologies. The market potential of HTST electricity generation was examined and modelled to determine the LCOE for various options. HTST was considered to have advantages over other renewables in that it could integrate well with conventional thermodynamic cycles and power plant equipment.

The economic potential of hybridisation was considered to be high, as associated capital costs were relatively low. Solar input was likely to be limited to ~5% of the thermal capacity – if greater, there was increased risk of thermal imbalance. However, later studies suggested that under the appropriate conditions, it could be possible for a solar assist system to provide up to 25% of the energy input (New South Wales and Victorian Governments, 2008). This would require full superheated steam generation, not simply feedwater pre-heating. The other limiting factor was the availability of suitable land to support the solar collectors – an estimated 4000 m^2 would be required per MW of capacity.

More than 20 Australian power plants were identified as having adequate solar resource and the necessary land. If a potential maximum 25% of load was assumed for the CSP contribution, then an average CSP equivalent capacity of 100 MWe per power plant was considered feasible. If 25% of each station's output was provided by solar, once fully developed, the sector could deliver up to 2 GWe of CSP equivalent capacity.

At the time, the capacity of solar assist with moderate-high prospects of proceeding were estimated at ~460 MWe, or ~1% of total Australian installed generating capacity. Solar assist could provide a near-term niche market for proven HTST technologies. Assuming a capacity factor of ~13% for the solar component, this capacity would contribute ~525 GWh of generation. However, limiting factors included the lack of available land at some sites, low coal costs, and the remaining lifetime of some power plants. Favourable factors included reduced power plant emissions, and extended working life of some coal resources. Some power plant sites had better solar resources than others. Thus, many of the Queensland coalfields and power stations were in locations of high solar intensity. Others, such as those in the Hunter Region of New South Wales, had more limited potential – for example, the Liddell power plant (*see* below).

Historically, the idea of combining CSP with coal-fired power plants was viewed fairly optimistically in Australia. But more recently, this interest appears to have waned and several major projects have failed to proceed, been abandoned, or only operated in conjunction with coal for a limited period. For a variety of reasons, only one progressed to commercial operation. The individual projects are described below.

Kogan Creek power plant, Queensland

The Queensland government-owned utility CS Energy developed plans for a 44 MW solar thermal add-on to its 750 MW supercritical coal-fired Kogan Creek plant. The plant fires ~2.8 Mt/y of bituminous coal. The proposed US$110 million project (the *Kogan Creek Solar Boost Project*) would have been the largest project of its type in the Southern Hemisphere, the world's largest coal-solar hybrid power plant project, and the largest CLFR solar CSP installation.

Heat from the Fresnel-based solar technology was to be used to produce 270–500°C high-pressure steam, fed to the steam turbine, increasing plant output. An estimated 35,600 t/y of CO_2 (~0.8% of the plant's total emission) could have been avoided. Construction began in 2011 and was originally scheduled to be completed in 2013 (Figure 9). However, unspecified technical difficulties and commercial issues meant that the commissioning date was delayed to 2015. In March 2016, CS Energy announced that the troubled project would not be completed, even though nearly A$40 million had already been spent. Apparently, little on-site progress had been made since 2013. Reportedly, the main issues were 'technical' difficulties associated with the solar thermal boiler tubes, although contractual difficulties were also cited as a factor. CS Energy announced that the solar addition could not be commercially deployed without further substantial costs and that there was no prospect of getting a positive return on that investment. The project was considered to be economically unviable (Parkinson, 2016).

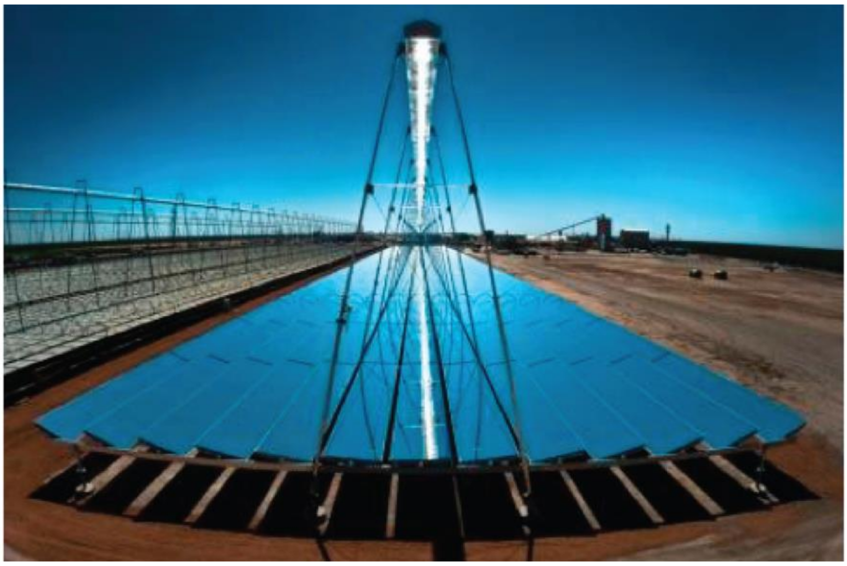

Figure 9 Part of the Kogan Creek solar installation (photograph courtesy of CS Energy)

Port Augusta project, South Australia

In 2014, the Australian Renewable Energy Agency (ARENA) funded a feasibility study to assess replacing with CSP or hybridising the Northern 1, Northern2, and Playford B coal-fired power plants in Port Augusta, South Australia. ARENA contributed A$1 million for the study while Alinta, the plant's owner, invested A$1.2 million, and the South Australia Government, a further A$132,000 (CSP World, 2014). The study assessed both CSP-only and hybrid approaches and was completed in 2016.

A range of possible plant options was considered that included a number of CSP plant configurations, forward price curves, and adjustments to capital and operating costs, revenue stream, and capital grant funding. One option was for a 50 MW stand-alone CSP project (using a power tower-based system) to be located near Port Augusta's existing power stations. It was considered that, compared to a coal-solar hybrid, this had a lower technical risk and the capability to operate on a longer life cycle. Furthermore, the high temperatures generated would have made it compatible with molten salt storage (ARENA, 2014). However, the project was deemed as economically unviable. In order to attract private sector investment, plant costs would need to be reduced by ~60%. This would reduce the LCOE from A$201 per MWh to A$80.

There is now little prospect for a coal-solar hybrid option to proceed at these sites. In June 2015, Alinta Energy announced that by 2018, it intended to close the Northern and Playford power plants along with the Leigh Creek Coal Mine that supplies their coal. Furthermore, analysis by the Australian Energy Market Operator suggests that the grid in South Australia is currently oversupplied, leading to a disincentive to add generation capacity of any kind (Alinta, 2015). The impending closure of the Port Augusta power plants is not expected to materially affect the oversupply situation.

In August 2017, it was announced that approval had been granted for the world's biggest solar thermal power plant (150 MW) to be built at Port Augusta. It will incorporate a molten salt thermal storage system that will extend operating time by up to 8 hours. Work on the US$510 million plant will start in 2018 and should be completed by 2020. The plant's design will be based on that of the 110 MW Crescent Dunes plant in Nevada, USA. Solar Reserve was the contractor for US plant and will also build the Port Augusta unit. It is claimed that the cost per MW will be similar to that of wind power and solar PV plants.

Liddell Power Station, Hunter Valley, New South Wales

A coal-solar hybrid project using a CLFR system with a total mirror surface of 18,500 m^2 was built at Macquarie Generation's 2 GW coal-fired Liddell Power Station in New South Wales (Figure 10). The project received A$9.25 million from the NSW Government Climate Change Fund Renewable Energy Development Program and followed on from the successful operation of a smaller (1 MW) CLFR test field set up at the plant in 2004 (AUSTELA, 2014).

Figure 10 Novatec solar boiler and solar field at the Liddell power station, New South Wales (photograph courtesy of Novatech)

The Liddell project incorporated a 9.3 MWth capacity Novatec solar boiler to provide saturated steam for preheating boiler feedwater. The CSP system became fully operational in February 2013. Coal consumption was reduced and CO_2 emissions cut by ~5000 t/y. However, in 2016 the solar project was closed down. Various contributing factors were cited that included technical and contractual issues that had resulted in lengthy delays and commercial problems. Furthermore, the operator no longer felt that solar boost was the most appropriate technology to advance the company's renewable energy future (Parkinson, 2016).

Collinsville Power Station, Queensland

As part of investigations into the possible hybridising of some existing coal-fired power stations in order to extend their working lives, a feasibility study was undertaken in 2015 for the 180 MW Collinsville power plant in Queensland. This considered the plant's conversion to gas firing integrated with a 30 MW solar system. However, it was concluded that the project was not feasible at the time as capital costs would be too high. However, it was considered that the project had assisted with the future deployment of solar thermal technologies in Australia by demonstrating where cost reductions were still needed to improve economic viability.

Australian non-power applications

Studies have examined possible ways that CSP could be harnessed in conjunction with coal, such as the use of solar power to gasify lignite. Concentrated solar radiation would be used to drive directly thermochemical reactions involved in the process. Direct conversion of coal to liquids has also been examined and the technical and economic viability of a number of possible options considered:

- use of solar process heat;
- low temperature supercritical water gasification of lignite in a linear concentrator;
- direct coal-to-liquids reactions in a linear concentrator;
- gasification within a high temperature solar-heated molten salt tank;
- high temperature supercritical water gasification using a tower or dish concentrator; and
- entrained flow or fluidised bed gasification using a tower concentrator.

Such solar-driven technologies are still at the R&D stage and the associated economics of large scale application remain unclear. However, as with many forms of technology, costs tend to reduce as development proceeds. Advantageously, the input from solar systems feeding into a coal-based process would help reduce overall CO_2 emissions by replacing part of the coal feed. To date, most efforts have focused on the application of CSP systems for utility-scale power generation. However, the principle of driving high-temperature endothermic reactions with CSP is well established in the R&D phase. Conversion of hydrocarbons such as lignite using solar heat appears to be technically feasible via a number of routes.

A Concentrated Solar Fuels (CSF) technology roadmap was published in May 2016, focused on the use of solar power for the production of a range of end-products. In this context, CSF comprise combustible fuels (both liquid and gaseous) that can be made or partly made utilising concentrated solar energy. This is transformed into chemical energy for use in a variety of applications. Potential CSF products include synthetic diesel, gasoline, methanol, ammonia and hydrogen (Hinkley, 2016).

The 4-year project leading up to the Roadmap's publication examined the challenges and solutions to the implementation of a CSF industry by considering technology development, societal acceptance, market development, and customer demand. R&D priorities and key areas were identified that included thermal storage, the development of high temperature materials and HTF, and low-cost storage solutions for hydrogen and syngas. It was assumed that a CSF industry would use similar tower and heliostat CSP technology, enabling it to capitalise on future technological developments and cost reduction.

CSF shows potential for reducing Australia's CO_2 emissions. To date, renewables development has concentrated mainly on electricity generation. However, ~80% of global and Australian primary energy demand is currently supplied by petroleum and gas, used mainly for transport and heat. The Roadmap suggests that CSF could provide a variety of low emissions fuels.

The process of creating a CSF for market would involve a primary solar-driven stage to produce either pure hydrogen or syngas, followed by a range of possible secondary processes to produce one or more saleable fuels. The Roadmap examined various production options, one of which was coal-solar (and biomass) gasification. Compared to some other options, this route had higher greenhouse gas intensity and possible issues of handling solids (as opposed to gases). However, lignite did have a low syngas production cost of around ~ 5 A$/GJ, due to the low feedstock costs. The final levelised cost of fuel (LCOF) based on the solar processing of feedstocks such as coal and natural gas, was projected to be competitive by ~2020 with conventional oil-derived fuels.

5.2.3 Chile

Chile is experiencing rapid economic growth and interest in the use of solar power has grown. As part of this, the potential of hybrid coal-solar and PV plants in the country has been assessed. Chile operates several electricity grids. The central grid has variable hourly demand, whereas the northern one experiences almost constant demand. The country has a sizeable mining industry, located mainly in the north, which is responsible for a significant proportion of demand. In Chile, yearly total direct normal irradiation (DNI) levels are >3000 kWh/m^2 in most of the country, with >3500 kWh/m^2 in the Atacama Desert – the high levels in the north are an important factor in the provision of electricity to the mining sector.

Chile relies heavily on imported oil and gas but needs more electricity generating capacity. Currently, around a third of Chile's electricity comes from hydro facilities although recent droughts have resulted in a series of power cuts. The country is developing a market for renewable energy in general and solar energy in particular. Recent legislation mandates a renewable energy quota of up to 10% of electricity generated by 2024. Solar energy is currently at the initial stages of market penetration, and several projects are being developed that include PV, CSP, and industrial heat supply plants. However, even though the country has significant solar potential, its contribution to the national energy mix is still small.

The northern regions have considerable potential for the deployment of solar-based projects and several different concepts have been proposed or are in development. These comprise a number of hybrid CSP+PV plants such as a 110 MW molten salt tower combined with a 100 MW PV plant, and a 110 MW molten salt tower with a 60 MW PV plant. The idea behind this concept is that the CSP plant dispatches in response to the PV output at the time. This is considered to provide a lower cost solution than could be attained by a stand-alone CSP plant, and allows operating conditions closer to conventional base load (Starke and others, 2015). In addition, a coal-solar hybrid is also being developed (at Mejillones, *see* below).

Mejillones power plant, northern Chile

The existing 320 MW coal-fired power plant comprises two subcritical PCC units of 150 MW and 170 MW that fire various types of bituminous and subbituminous coals. The intention is to integrate a CSP system with the 150 MW unit and to use a CLFR system supplied by Solar Power Group of Germany. This will produce superheated steam via a solar boiler that will be fed directly to the power plant. Development of the 5 MW scheme is being undertaken by GDF Suez and Solar Power (HELIO CSP, 2014). Steam produced will be purchased by E-CL, the utility owned by GDF Suez that supplies power to Chile's northern grid. No further details of the Mejillones hybrid project have yet been made public.

Studies undertaken by Solar Power Group examined a nominal 350 MW Chilean coal-fired power plant combined with a 6 MW solar add-on. In this case, it was concluded that solar power could provide ~1.5% of the plant's overall output. This would increase plant efficiency by 1% and reduce coal demand by ~20 kt/y.

5.2.4 Macedonia

The feasibility of developing a hybrid has been considered for the lignite-fired Bitola power station. Bitola's three 225 MW units provide 70% of the country's electricity. The plant consumes around 6.5 Mt/y of lignite and generates ~4.34 million MWh/y. As part of Macedonia's Energy Development Strategy 2013-2017, aimed mainly at improving the country's energy security, the plant's operator JSC Macedonian Power Plants (ELEM) has been carrying out a major overhaul and modernisation of the plant.

A feasibility study was also undertaken to examine the possibility of incorporating solar power. This was carried out by French companies Artelia and Carbonium to determine the most appropriate technical option for a CSP plant to be located close to the Bitola site. It included a study on the use of the Clean Development Mechanism, an environmental impact assessment, and a detailed financial analysis (Nikolov and others, 2012). The preferred option was the use of CSP to preheat plant feedwater, injecting steam between the last high pressure water heaters in the entrance to the boiler. Using a heat exchanger, input from the CSP would increase water temperature from 250°C to 285°C, enabling a reduction in the amount of lignite burned (Nikolov and others, 2013).

A further study was carried out in 2016. The thermal capacity of the solar field proposed was ~50 MWth, insufficient to replace entirely one of the existing 225 MW lignite-fired units. Two possible options were considered, namely direct heating of a working fluid with electricity production in a new thermal power plant, and partial replacement of coal demand for steam and electricity generation in the existing Bitola units. The second approach was preferred. Several possible options for integrating solar heat were examined: injection in the cold reheat stream, boiler feedwater preheating, HP feedwater heater bypass, or LP feed water heater bypass – boiler feedwater was selected as the most appropriate. In operation, this system would produce steam at 285°C/15.5 MPa.

It was considered that the proposed coal-solar hybrid could be an effective approach towards substituting fossil fuels with renewable energy sources. Depending on the hybridisation option selected, there would only be a modest increase in the cost of electricity generated:

- conversion of one 225 MW unit – 0.21 €cents/kWhe (increase of 5.2%);
- conversion of three 225 MW units – 0.07 €cents/kWhe (increase of 1.8%); and
- conversion of ELEM's entire output – 0.05 €cents/kWhe (increase of 1.3%).

Financially, this was considered an attractive solution compared with the cost of electricity from PV plants or investment in other emerging technologies such as CCS. As such, it was concluded that hybridisation deserved further investigation and could form the basis of a cost-effective and environmentally acceptable means of combining coal and renewables (Cingoski and others, 2016).

5.2.5 South Africa

The South African power generation market is dominated by coal-fired generating plants and is under increasing pressure to increase efficiency and reduce emissions. Various initiatives are under way. As the country has good solar resources, there appear to be opportunities for solar-based systems to make a significant contribution towards meeting electricity demand. Alongside stand-alone CSP plants, there is also potential for coal-solar hybrids. In 2012, it was reported that Eskom had the potential to augment its existing coal-fired fleet with as much as 2 GW of hybrid power capacity (Helio CSP, 2012). A further 1 GW of potential was associated with coal-fired plants under construction. The adoption of hybridisation would reduce the amount of coal burned, and could add between 5% and 10% of additional capacity (Creamer, 2012).

Technology supplier GE/Alstom agreed with these findings, noting that this would lower emissions and create a more cost-effective entry point for CSP-based power options. Hybridisation of some coal plants that had at least 25 years of lifetime left was considered technically feasible and could materially reduce subsidies needed for the inclusion of CSP into the country's generation mix. The company believed that hybridisation offered a bridging technology, enabling CSP-based systems in general to gain scale.

More recent studies have compared stand-alone CSP with coal-solar hybridisation (or solar-aided power generation – SAPG). The simulated stand-alone CSP facility was located near Upington, Northern Cape, and the SAPG unit at Lephalale in Limpopo province, location of the existing coal-fired Matimba and Mendupi power plants. The SAPG plant was based on a generic 600 MW subcritical unit and potentially, could be operated in both coal saving and solar boost mode. The same power block specifications were used for both plants. The CSP facility considered would provide ~50 MWth peak capacity. In this case, the option of incorporating thermal energy storage was not considered (Pierce, 2013). The main conclusions were:

- in terms of the conversion of solar thermal energy, SAPG was 1.5 times more efficient than stand-alone CSP;
- ultimately, the annual electricity generated from solar thermal at the SAPG plant was >25% more than from the stand-alone CSP plant;
- SAPG was 72% of the cost of CSP. A solar-assisted high pressure feedwater heater system at an existing coal-fired power station would be 1.8 times more cost-effective than a stand-alone CSP plant; and
- the LCOE from SAPG would be competitive with large scale, ground-based PV plants.

Thus, it was concluded that in the near-medium term, SAPG was a viable option. Hybridisation in this manner could help utilities to meet CO_2 emission reduction targets quickly and economically (Pierce and others, 2013; Aurecon Group, 2013). Furthermore, much of the equipment needed could be manufactured locally.

In 2015, further solar augmentation studies were undertaken by the North-West University (Van Rooy and Storm, 2015). These again noted the high LCOE generated by intermittent renewables, compared to coal-fired plants. The study determined that to generate 1 kWh of electrical energy from a CLFR-based CSP plant (without thermal storage) would cost ~R3.08, compared to R0.711 for 1 kWh generated by a modern supercritical coal plant (taking carbon taxes into account). The high LCOE results mainly from the significant capital investment required per kW of installed capacity, compounded by solar's intermittency and often low capacity factor.

Estimated LCOE for a coal-solar hybrid was less than that of a stand-alone CSP plant. By integrating a heat exchanger (90 MW peak thermal) in fuel saving mode, the hybridised system would produce ~4.6 GWh/y more electricity than the unmodified coal-fired plant. This increase resulted from reduced auxiliary power consumption during periods of high solar irradiation. Under the circumstances considered, coal consumption would be reduced by ~22 kt/y, reducing CO_2 emissions by 38.7 kt. Ash production would also be reduced by ~7.6 kt.

The electricity generated by the incorporation of solar energy would produce an extra ~R8.188 million per year in additional revenue from the trade of renewable energy certificates. Reduced coal consumption would also save ~R6.189 million. Lower CO_2 emissions would reduce the carbon tax bill by R1.856 million per year, and by supplying extra energy to the grid, the power plant would earn an additional ~R3.037 million. However, O&M costs would increase by ~R9.71 million because of the requirements of the 171,000 m^2 solar field. At R0.714/kWh, generating 1 kWh with the hybridised plant would cost only 0.34 cents more than an unmodified supercritical equivalent. Earlier thermodynamic analysis concluded that for a nominal 500 MW subcritical plant, ~5–6% fuel could be saved by using solar energy for feedwater preheating (Suresh and others, 2010).

Eskom has continued its work on solar augmentation and its potential, and a number of different designs have been considered:

- separate heat exchanger for feed water heating;
- direct steam injection for HP feed water heating;
- direct steam injection for boiler feed pump turbine & DST heating;
- direct steam injection into hot reheat line;
- direct steam injection into main steam line; and
- direct steam injection into cold reheat line.

Work has encompassed different modes of operation, namely reduced coal consumption, additional power output, and additional dispatchable capacity used to meet morning and evening demand peaks. Around 10 MWe was considered as the minimum viable capacity of any CSP system added.

The potential for hybridisation was considered for each of Eskom's coal-fired plants. The main criteria were adequate solar resource, and land-related issues such as size, topography and proximity to the power plant, as well as possible future expansion. Relevant factors included years of operation remaining, capacity factor, current performance, and emission issues.

The work examined technical-operational and financial viability, capital and O&M costs, LCOE for each option, and identification of risks, fatal flaws, and risk treatment plans. The stations were then ranked and concept designs developed for selected sites. Not all of the thirteen plants were deemed suitable for solar augmentation (Table 5). However, four were recommended for further consideration (Vikesh, 2014a and 2014b).

Table 5 Potential Eskom sites for solar augmentation (Vikesh, 2014a)

Power plant	Pass or fail	Reasons for rejection
Camden	Fail	Fatal flaw (land)
Komati	Fail	Fatal flaw (land)
Grootvlei	Fail	Lifespan and unit size
Hendrina	Fail	Lifespan and unit size
Duvha	Fail	Individual land parcel size
Matimba	Fail	Cooling plant constraints
Arnot	Fail	Capacity factor
Kriel	Fail	Coal beneficiation and mine expansion
Lethabo	Fail	Mining activity and water level
Kendal	Pass	
Majuba	Pass	
Matla	Pass	
Tutka	Pass	

As well as existing stations, projects in development have since also been addressed – for example, the 6 x 794 MW supercritical Mendupi plant in Limpopo Province, where the first unit was synchronised in 2015. Once fully operational, the plant will be the fourth largest coal plant in the southern hemisphere, and the biggest dry-cooled power station in the world. Planned operational life of the station is 50 years.

The level of solar radiation at Mendupi was estimated to be 2527 kWh/m^2/y. Several possible CSP options were considered that included a CLFR system for feedwater preheating, a combination of direct steam injection (IP) and feed water preheating, plus a parabolic trough system for feedwater preheating and direct IP steam injection. It was assumed that adequate land and water resources would be available around the existing plant, and that during hybrid operation, it would operate at constant output (reduced coal consumption). In operation, steam generator load during hybrid operation would be dependent on the operating strategy adopted, but would fall between 87.0% and 90.5% boiler maximum continuous rating (BMCR) (Hoffmeister and Bergins, 2012). The most suitable and economic solar technology was deemed to be Fresnel technology used for HP heater bypass.

At the moment, the future of solar-based systems in general in South Africa is unclear, as after many years of electricity shortage, the country now has a modest surplus. This has resulted from new coal-fired capacity coming on line coupled with a slowdown in the national economy. Thus, apart from projects already underway, there is little incentive to build new power plants of any type.

5.3 European activities

Some European Union (EU) member states use coal to generate a significant proportion of their electricity. A number also experience lengthy periods of high intensity sunlight for much of the year. Hence there appear to be opportunities for combining these two technologies. Although there are currently no utility-scale hybrid projects in operation in the EU, the possibilities have been examined. For example, in 2012, Chalmers University of Technology determined the EU technical potential to integrate CSP collectors with existing gas- and coal-fired plants. It was concluded that ~1.6 GWe (3.0 TWh/y) of solar capacity could be added to existing fossil fuel-fired plants at sites where solar radiation was at least 1800 kWh/m^2/y (Pihl and Johnsson, 2012). Deployment of hybrids could provide a pathway to implementing and maturing the technology at lower costs than greenfield installations.

Most of the potential is in the southernmost countries. Individual power plant sites were graded for land availability and solar resource. Of those with adequate solar intensity, 40% of technical potential capacity was in Spain, 40% in Italy, 12% in Portugal, 6% in France, and 2% in Greece. In the countries selected, a total of 68.7 GW of gas plants and 15.8 GW of coal plants were found to be theoretically available for retrofit. Older units, with less than 15 years of operating lifetime remaining, were excluded from the study. The hybridisation of existing fossil fuel-fired power plants in the member states selected could more than double the solar thermal power capacity (as of 2012), at a lower cost than building the same capacity as greenfield CSP plants. Solar retrofitting could provide faster and cheaper coal-solar hybrid deployment, alongside the building of stand-alone plants.

For more than a decade, the EU has supported CSP-related activities via a number of Framework Programmes. R&D has encompassed the major CSP variants such as parabolic trough technology, power towers, and molten salt thermal storage. EU funding has helped develop different technological approaches, assess their economic viability, increase their operability, and reduce the cost of CSP. It has also supported R&D into hybrid coal-solar and gas-solar technologies (Europa, 2016). For example, as part of the 6th Framework Programme, a project entitled *PV Catapult* brought together a number of organisations to identify research and market opportunities, and undertake performance assessment of several solar-based options that included hybrid solar systems (Europa, nd).

5.3.1 China

Parts of China have serious air pollution problems and it is a government priority to reduce these. Strategies include the greater use of wind and solar power. The country has abundant solar energy resources and large areas of unused land, making some regions suitable for the development of solar thermal power generation. Coal-solar hybridisation has been suggested as part of this strategy. A number of Chinese studies have examined the concept although no demonstration projects have yet been built. Various sizes of power plant, solar collection device, and methods for their combination have been investigated, and reportedly, some pilot scale investigations have also been undertaken (Lo, 2014).

A recent study carried out by the Institute of Engineering Thermophysics of the Chinese Academy of Sciences examined the potential for a 330 MW coal-solar hybrid located in Changji City, Sinkiang province. Solar energy would be used to generate steam at ~300°C, used for boiler feedwater heating. Thermal storage did not form part of this project, hence when solar energy was lacking, output from the coal-fired plant would be ramped up to compensate.

Annual solar radiation of the Changji site was ~1319 kWh/m^2. It was estimated that the annual net solar-to-electricity efficiency could reach as high as 21%, an improvement of nearly 3 percentage points over a corresponding state-of-the-art stand-alone CSP power plant. Furthermore, the LCOE could be reduced to 0.8–1.0/kWh, about 20–30% lower than that of the solar-only thermal plant (at 1.1–1.3/kWh). Overall, the coal-solar hybrid was considered to have major advantages over a stand-alone solar equivalent (Peng and others, 2014; Hong and others, 2013). It would generate electricity more cheaply by utilising mid-temperature solar heat, as well as achieve better off-design performance. The technology was considered to offer a promising approach to the cost-effective and scalable utilisation of mid-temperature solar heat.

Other studies carried out by the Institute of Engineering Thermophysics considered a hybrid project at an existing 200 MW coal-fired power plant in Inner Mongolia. This would incorporate a solar-based system of ~10 MWe capacity. Mid-temperature solar heat would be used to preheat the coal-fired plant's boiler feedwater (Zhao and others, 2016a).

The North China Electric Power University examined hybridisation for feedwater heating at a power plant in Lhasa (Hou and others, 2012). Other studies modelled the performance of a newly built 600 MW hybrid, again, featuring feedwater heating. Analysis suggested that when operating at the rated capacity, the contribution from solar power would be ~29 MWe (Zhai and others, 2013).

Work undertaken by the Technical University of Lisbon considered the hybridisation of a typical 500 MW coal-fired Chinese power plant firing a subbituminous coal. Steam produced by a CLFR system would be used to increase the plant's power output. It would be injected into the extraction line of the high-pressure turbine, effectively reducing extraction and thereby increasing mass flow. The solar contribution would be ~4.5 MWe, nearly 1% increase in total plant output (de Sousa, 2011).

5.3.2 India

India has been pursuing a number of initiatives for some time, aimed at increasing the deployment of renewables such as solar power, whilst simultaneously attempting to reduce coal demand. As part of this, in 2010, the Government of India and individual State Governments initiated a major programme (*the Jawaharlal Nehru National Solar Mission – Towards Building Solar India*) to promote ecologically sustainable growth while simultaneously addressing India's energy security challenge. Reasons cited for the greater uptake of solar power include:

- improved energy security;
- reduced coal imports (possibly by 8–10%) (Kishore, 2013);

- reduced CO_2 emissions (Solar India, nd); and
- protection of investments made in the existing coal-fired power fleet.

The *Indian National Action Plan on Climate Change* has noted the country's significant solar resources – these have great potential as a source of energy, and an ambitious target of deploying 20 GW of grid-connected solar power by 2022 has been adopted (Ministry of New and Renewable Energy (2017).

In recent years, the viability of deploying stand-alone CSP plants in India has been examined. However, electricity from this source is more expensive than that from coal-fired power plants and PV-based systems. Thus, a major objective of the Solar Mission is to drive down costs towards grid parity via rapid scale-up of capacity and technological innovation. The Mission envisages achieving this by 2022, and parity with coal-based power by 2030. However, this will be dependent on future costs and the scale of global deployment and technology development and transfer. Pilot and demonstration projects are intended to promote further technology development and cost reduction and it is envisaged that this will include a 100–150 MW solar hybrid plant with coal, gas or biomass.

Much of India receives a high level of DNI of 4–7 kWh/m^2/d. Thus, there is a considerable potential for decentralised solar energy applications based on CSP. Future emphasis is expected to be on the greater deployment of PV systems, although limited progress is also being made with the development of CSP capacity within the country. However, the current cost of stand-alone CSP generation is higher than that of PV, a major market challenge (Nixon and others, 2013). The capital cost for solar PV is Rs 5.87 crore per MW, whereas that of stand-alone CSP is Rs 12 crore. Given the higher costs, solar thermal power plants have a questionable future unless prices can be brought down through the development of an indigenous manufacturing base (CSE India, 2015).

Ambitious targets have been set for the uptake of solar power and as part of this, the Indian government has instructed the National Thermal Power Corporation (NTPC) to sell (more expensive) solar-generated electricity with cheaper coal power as a single unit. NTPC has been tasked with building 15 GW of solar plants by 2019. Thus, the company will bundle and sell electricity from coal and solar PV to the grid. There has been some opposition, as bundling is expected to increase the overall cost of electricity. However, five coal plants with a total capacity of 8.96 GW will take part in the programme – the 1.7 GW Singrauli plant in northern India will be the first to begin bundling, with the plant's output being sold along with electricity from 3 GW of solar installations (Meza, 2015). Alongside this initiative, Coal India Ltd (CIL) has signed a pact with Solar Energy Corporation of India (SECI) for 1 GW of solar power projects in different parts of the country. CIL has so far installed several small projects in two of its subsidiaries However, as noted above, these projects will not be integrated hybrids, merely two systems co-located at the same site. There are concerns that considerable areas of land will be needed in order to accommodate the large amounts of PV capacity that the Indian government aspires to, and this is not always available due to various constraints (Barnes, 2017).

There is some limited promotion of coal-solar hybrids. For example, the Indian Centre for Science and Environment (CSE) considers that hybridisation would provide an easy route for integrating CSP with thermal power plants. CSE considers that coal-solar hybrids would enhance grid flexibility, reduce CSP costs, and boost power plant performance, and has recommended the development of pilot projects that include thermal storage; these would act as test beds for assessing plant components. Furthermore, CSE recommends that wherever possible, hybridisation should be given first preference and that existing coal-fired power plants that have adequate land available (particularly in Rajasthan and Gujarat) should be identified (CSE India, 2015). Currently, there are no hybrid solar thermal plants operational in India although reportedly, some pilot scale investigations have been undertaken (Lo, 2014). In a recent development, NTPC announced the start of a coal-solar hybrid project (the Integrated Solar Thermal Hybrid Plant – ISTHP) being set up at its Dadri power plant – this will be the first Indian project to use solar energy to heat boiler feedwater, boosting plant efficiency. It will also help reduce coal demand. In order to save costs and manpower, the project will feature the robotic dry cleaning of the solar panels (ET Energy World, 2017).

The Indian Institute of Science (IISc) at Bengaluru is currently investigating the possibility of achieving at least 50% efficiency from Indian thermal power plants. As part of this, a laboratory-scale supercritical CO_2-based thermal test loop has been constructed to investigate integration with solar heating. The test facility has been designed to generate data needed for future development and scale-up of supercritical CO_2-based power plants. Expected outcomes for solar integration include lower power plant CO_2 emissions and increased plant capacity at lower operating costs (Basu, 2016). It is claimed that smaller turbines and power blocks would be required, reducing plant capital costs. The project is receiving financial support from the Department of Science and Technology (DST) via the Indo-US consortium project SERIIUS (Solar Energy Research Institute for India and US), IISc, and Indian Ministry of New and Renewable Energy (MNRE).

Hybridisation has also been considered for power plants that cofire coal and biomass (Nixon and others, 2013). The potential for biomass boilers in India is significant; more than 370 Mt/y of biomass is generated, although some is only available seasonally. Nixon and others (2013) considered that the future prospects were good for coal-solar-biomass hybrids was good (Nixon and others, 2013).

Over the past six years, India has installed a significant amount of solar power of various types that include a number of utility-scale stand-alone CSP plants. For example, in August 2016, American company First Solar began commercial operation of 130 MW solar projects in India – an 80 MW project in Andhra Pradesh and a 50 MW plant in Telangana. It is claimed that by replacing fossil fuels, these will displace >204 kt/y of CO_2 emissions. It is anticipated that many similar projects will be developed in the coming years, but no firm plans have yet been announced for the development of commercial-scale coal-solar hybrids.

5.3.3 Zimbabwe

Various developing nations have considered the integration of solar technology with existing coal-fired power plants – Zimbabwe is an example. Feasibility studies have examined the potential for hybridisation of the existing Harare power plant through the addition of CSP based on the use of concentrating parabolic troughs. The Harare station uses pulverised coal combustion technology but only has an overall 'dependable' capacity of only around 60 MW (2 x 30 MW generators). However, it was concluded that hybridisation was a feasible option and that it had the potential to boost power plant output and reduce CO_2 (Madiye and others, 2013). A positive outcome could encourage additional project at existing power plants in other African countries.

5.4 Summary

Any solar-based generation technology, including hybrids, is limited to regions that benefit from relatively high levels of solar radiation.

Not all projects reported in the media as 'hybrids' are true hybrids – often the solar component is PV-based, so is simply co-located on the same site with both systems operating independently.

Any proposed coal-solar hybrids need to be evaluated on a case-by-case basis as designs are extremely site-dependent. Project viability is influenced by multiple factors, and the optimum configuration will depend on the specific parameters. Each proposed hybrid needs tailoring to meet individual requirements. The progress of an individual project is likely to be affected by a combination of economic, environmental and political considerations.

The incremental costs of the CSP part of a hybrid plant are often comparable to that of a PV installation of equivalent capacity. However, both stand-alone CSP (with thermal storage), or hybridisation offers dispatchable energy and at a much higher rate of operational flexibility than PV. Hybridisation is considered to offer the most cost-effective and efficient feed-in of solar energy into a grid.

The capital investment and cost of electricity is lower for a coal-solar hybrid than for a stand-alone CSP plant – the LCOE from a hybrid could be up to 30% less. When additional capacity payments, time-of-day prices, and economic benefits of operational flexibility are factored in, the economic advantage of hybrid plants increases further.

As both are dependent on the availability of sunlight, output from a hybrid operating in solar boost mode can be as variable as PV. However, when in coal saving mode, electricity is dispatchable. Thus, the system regulator can rely on power being available.

Depending on local circumstances and prevailing environmental legislation, as electricity from a coal-solar hybrid is not 100% 'green', it may not qualify for some environmental incentives.

Although some technical challenges remain, none are considered insurmountable. Most plant components and systems are already available although integration issues will differ between individual plants. Some technical challenges may apply where solar technology is retrofitted to an existing coal-fired plant. However, these may be avoidable with new-build plant as the coal- and solar-based systems can be integrated fully at the design stage.

So far, hybridisation efforts have been focused mainly on the retrofitting of existing coal-fired power plants. As some of these have been older small capacity units, sometimes scheduled for retirement, the integration of solar energy has not always been as effective as expected (such as the Cameo project in the USA). The overall condition of the coal plant has usually been a factor in this.

The biggest potential market is considered to lie in solar integration with new highly efficient coal-fired power plants. By incorporating solar power at the design stage, it is predicted that much higher levels of solar energy could be utilised.

6 Coal-gas cofiring

6.1 Why cofire natural gas with coal?

Both coal- and natural gas-based power generation technologies are vital in powering many of the world's developed and emerging economies. Both are used widely to provide secure uninterrupted electricity, needed to ensure that economies and societies develop and prosper. In some countries, coal provides much of the power, in others, natural gas dominates. However, there are many instances where the national energy mix comprises combinations of the two. Each brings its own well-documented advantages and disadvantages. Recent years have seen a growing interest in ways that these two fuel sources might be combined in an environmentally-acceptable and cost-effective manner.

Changing market conditions are forcing many power plant operators to evaluate and implement alternate modes of operation such that their plants remain capable of dispatching electricity in an efficient and cost-effective manner. Important tools in meeting these criteria are fuel and operational flexibility. There are various ways for existing coal-fired power plants to achieve this. For example, as noted in the first part of this report, there is the potential for some to incorporate solar energy. However, another possibility for existing coal-fired may be cofiring, replacing a percentage of the coal feed with natural gas and burning them together. Within this context, cofiring is the combustion of two different fuels simultaneously to produce heat in a steam generator – it is often implemented in coal-fired power plants using natural gas, or sometimes fuel oil.

In some economies, coal-fired plants are facing increasing competition from natural gas and renewables. Furthermore, environmental legislation is being tightened, aimed at reducing permissible levels of SO_2, NOx, particulates and CO_2. Thus, many plant operators face the dilemma of whether to invest in emission control equipment or withdraw their plant from service. Many coal-fired power plants in, for example, the USA, currently face this situation. There are several possible options open to plant operators:

- decommissioning of the coal-fired facility;
- complete conversion from coal firing to natural gas;
- using gas to reduce plant emissions (for example, reburning for NOx control); or
- a switch to coal-natural gas cofiring.

A number of utilities are considering converting some of their coal plants to gas cofiring, such that they can operate on a mix of the two. Importantly, some are evaluating systems whereby the ratio of coal:gas can be changed, providing a degree of flexibility in terms of fuel supply. In the USA, a number of plant operators are investigating the test firing of natural gas to determine the long-term feasibility of either full conversion or dual-fuel firing. Others are undertaking feasibility studies to evaluate the possible ramifications of cofiring.

The cost of generating electricity from coal or gas can be similar. Even slight changes in fuel price can result in significant swings in production costs, and this can create market opportunities for utilities that have both gas- and coal-fired assets. Cofiring can be a possible option, allowing pricing and market conditions to drive the fuel choice and mix (Nowling, 2016). Substituting some coal input with gas is considered to be a low-risk option, allowing utilities to better meet changing market requirements.

In the coming years, natural gas is forecast to continue partially replacing coal for power generation in some major economies. Thus, the operating advantage will go to utilities with diversified fleets capable of switching between coal and gas as the market price of each fluctuates. This will be of particular advantage during periods of flat electricity growth, such as that experienced in the USA in recent years.

Adding gas to coal-fired plants offers utilities the possibility of rapid response to changes in load demand and deep cycling capability, but retains the ability to fire low cost coal. In economies where electricity demand fluctuates, a power plant that can cycle quickly to meet peaks and troughs in demand, and also ramp down during periods of low demand, is more likely to be profitable. However, most coal-fired units can only operate as low as 30–35% load and still sustain good combustion, restricting the plant's ability to cycle. Furthermore, coal plants can be slow to cycle up to full load – this can take 12 hours or more to ramp up to load from a cold start (Gossard, 2015). A plant capable of switching to gas at low loads and take load down even further, then switch back to coal at higher loads, could be at an advantage over the competition.

As noted, in the US coal-fired generating sector, cofiring natural gas is one option being considered. In an environment where operators of coal-fired assets are facing growing legislative and economic hurdles, cofiring may offer a means of achieving environmental compliance whilst still maintaining a significant level of coal consumption. Strict Environmental Protection Agency (EPA) emissions restrictions have already seen many older less efficient coal plants closed or converted to natural gas.

Cofiring offers increased fuel flexibility and potentially, this can provide significant fuel and operational savings. Many US coal-fired plants were built in an era when coal was cheap, environmental pressures were low, and there was only limited competition from other generating sources. Increasingly, many of these plants are now expected to operate in non-base load modes, something that most were not designed for. They need to adapt and evolve to survive in the longer term (Nowling, 2015). A major factor will be the ability to operate on fuels that they were not originally designed for. Hence, increased fuel flexibility is growing in importance. Cofiring introduces a second main fuel and can also offer the possibility of using lower cost/grade types of coal, generating even greater savings. The main reasons cited for cofiring are summarised in Table 6.

Table 6 Reasons for cofiring coal and natural gas
Environmental
Mitigating CO_2 emissions from coal-fired boilers
Reducing emissions of SO_2, NOx and particulates
Providing a mechanism for generation and sale of cost-effective, dispatchable electricity
Public acceptance
Economic
Maintenance of a coal supply sector and employment
Cofiring in existing boilers may be the least-cost way for coal-burning utilities to improve fuel flexibility
Cofiring could save money in competitive markets through fuel diversity
Cofiring could help companies get credits for early voluntary greenhouse gas abatement measures

6.2 Options for natural gas addition

Potentially, there are a number of ways in which natural gas can be combined with coal. Some replace a portion of the main coal feed whereas others are more focused on minimising plant emissions. Possible options are explored in the following sections.

6.2.1 Preheating coal prior to combustion

The addition of natural gas to coal-fired combustion can reduce NOx emissions. Preheating coal using gas-fired burners prior to combustion has been shown to help release fuel nitrogen and other volatiles, destroying NOx precursors, and thus reducing NOx formation.

In operation, a concentrated pulverised coal stream enters a preheating chamber where flue gas from natural gas combustion is used to rapidly heat the coal up to ~820°C prior to complete combustion in the PC burner. This thermal pre-treatment process releases coal volatiles, including fuel-bound nitrogen compounds, into an oxygen-deficient atmosphere that converts the coal-derived nitrogen compounds to molecular N_2, rather than NO. This allows the system to achieve lower NOx levels without the need for post-combustion flue gas clean-up technology. Coal preheating is claimed to provide more flexibility in burner operation, particularly with low-NOx burners (LNB), achieving minimum NOx production whilst maintaining acceptable carbon burnout. Thus, it appears to offer a means of feeding a relatively small amount of gas into a coal-based process, whilst helping reduce NOx formation (Bryan and others, 2005). However, there appear to be no utility-scale applications in operation.

6.2.2 Conversion to coal with natural gas cofiring

This technique can allow much higher amounts of gas to be fed into an existing boiler and burned simultaneously with the coal feed. The process entails modifying the boiler to make it capable of using combinations of coal and gas. Depending on the individual plant and operational requirements, there are a number of possible ways to reconfigure the existing unit such that cofiring becomes possible.

The simplest option is often to retrofit existing oil-fired ignitors with natural gas equivalents (Class 1 – *see* below) which typically allows for a maximum gas firing capability of 10–20%. If the unit is equipped with oil-fired warm-up guns, these can be replaced with natural gas-fired units – this increases potential natural gas capability to ~30–50%. Should a greater level be required, gas firing needs to be incorporated into the main burner system (Reinhart and others, 2012). This entails modifications such as the installation of gas rings around the existing coal burners, installation of gas spuds in the annulus or centre of the burner, or other means to allow for feeding gas in. Often, the most expensive option for cofiring is the addition of full-sized natural gas burners or the replacement of the existing coal burners with gas or dual-fuel units. For moderate levels of cofiring, modifications to the boiler and boiler auxiliary equipment may be minimal or even unnecessary, although changes to the combustion control system are likely to be required. If the plant's existing burner management system is of suitable age, it can probably be modified and reused.

Oil and gas igniters are deployed widely in coal-fired power plants, used to generate the heat needed to safely ignite coal, the main boiler fuel. The igniter fulfils three basic functions:

- furnace warm-up;
- ignition (light-off) of the main fuel; and
- load stabilisation.

In the USA, the National Fire Protection Association (NFPA) Regulation 85 covers standards aimed at preventing explosions in pulverised coal-fired multiple burner boiler furnaces. The Regulation classifies igniters into three types according to their intended operation (Table 7).

Table 7 Igniter types (Parent and Czarniecki, 2016)

Igniter type	Characteristics
Class 1	These are sized and arranged to ignite the main burner and support ignition under any burner light-off or operating conditions. They provide sufficient ignition energy to raise burner inputs of both air and fuel above the minimum ignition temperature. Ignition energy is generally >10% for the full load burner input
Class 2	These are used to ignite the fuel through the main burner under prescribed light-off conditions and to support ignition under low load or certain adverse conditions. They are not used to ignite the main flame during uncontrolled or abnormal conditions. They have a capacity range that is generally 4–10% of full load burner fuel input
Class 3	These are typically smaller igniters used with gas and oil burners to ignite under prescribed light-off conditions. Their capacities are generally less than 4% of the full-load burner fuel input

Of the different igniter types, Class 1 units provide the maximum flexibility in pulverised coal applications. They are the most versatile as they can provide burner ignition, stabilisation, and boiler warm-up. For pulverised fuel combustion, gas igniters are usually preferred over oil igniters as it avoids the need for oil atomisation. In the USA, this is further boosted by the current low price of natural gas. Class 1 igniters usually comprise a high-energy spark ignition rod, fuel gun, guide tube, and possibly a diffuser.

As so many coal-fired plants are now cycled regularly, high turndown ratios have become increasingly important for igniters. Plants are routinely called on to cycle according to electricity demand curves. Therefore, igniters need to be capable of functioning effectively during continuous, intermittent, and interrupted operational modes. Igniter turndown ratios of at least 2:1 are required for efficient igniter fuel utilisation during load following. For continuous service applications, the igniter fuel can account for a significant portion of total energy (Parent and Czarniecki, 2016).

Various types of burner assemblies are offered commercially, some designed specifically for cofiring. For example, Breen Energy Solutions of the USA has developed a proprietary system known as dual orifice cofiring. This was developed as an effective means for handling variable gas input to a coal-fired boiler. Potentially, there are a number of possible inlets for the gas supply. Feeding it at the igniter has merit as the gas is needed in this location. However, feeding in more gas than the device was designed to handle can cause problems. For example, it can create significant competition between the gas and coal flames for available oxygen. Furthermore, doubling or tripling the gas throughput can also place the resultant flame near the centre of the boiler, minimising waterwall steam creation and increasing superheat/reheat steam temperatures (Breen Energy Solutions, 2014).

Breen Energy Solutions has developed a system known as Enhanced Gas Cofiring (ECG) based on its dual orifice technology that aims to replace up to 35% of coal energy input with natural gas. This is achieved using a Class 1 dual-fuel outlet igniter coupled with a high volume, annular, secondary gas supply. An annular gas outlet surrounds the core igniter, a fixed flow device sized for the burner it supports. A secondary gas feed is controlled separately and depending on the individual plant requirements, can be fixed or variable. The ratio between the two fuel outlets is site specific – this is necessary to provide optimum flame stabilisation from the core and variable annular flow to keep cofire heat input near the walls, allowing for better steam production and minimal coal flame disruption. The Breen unit provides the ability to control natural gas heat input up to 35% of Maximum Unit Continuous Rating (MCR). This can significantly improve minimum unit load and load control, as well as produce lower plant emissions per unit of electricity generated. A key element of the system is the successful management and control of the combination of coal, igniter and cofire gas fuel streams in order to create the optimum environmental outcome. Between 5–7% of the unit heat input can be fed (as gas) into the upper furnace area of the coal-fired boiler; this also provides NOx reduction and selective catalytic convertor (SCR) benefits. Lower down, between 25% and 35% of unit MCR heat input (as gas) is also fed in at the burner level – this provides significant flexibility in terms of unit turn-down.

Other US manufacturers also produce dual-fuel burners. For example, Texas-based Forney and Storm Technologies have developed a proprietary system known as the Eagle Air burner. This is a wall-fired boiler dual-fuel burner that operates on coal or natural gas. Available in a range of capacities, it can operate on 100% coal or natural gas, and incorporates multiple zones of secondary air that allow for combustion and NOx tuning. Advantages cited include enhanced fuel flexibility, the ability to stage the gas and coal for improved combustion and emissions, and improved off-peak low load operation (meaning reduced cycling). It is claimed that these burners have allowed some coal-fired power plants, particularly smaller plants of

300 MW or less, to improve their efficiency and reduce emissions, thus extending their working lives. Thus, some plants have avoided closure (Forney, 2017). Other burner manufacturers include companies such as Riley Power.

Replacing a percentage of coal feed with gas will clearly help reduce overall plant emissions of SO_2, NOx, particulates, mercury, and CO_2. Breen Energy Solutions (2014) claims that replacement of 35% of coal feed using their cofiring system can reduce SO_2/SO_3 emissions by up to 35%, NOx emissions by 45%, particulates by 35%, mercury by 35%, and CO_2 by 20%. Stable low load operation can also be achieved. In the USA, the National Fire Protection Association also requires that two pulverisers are kept in service. However, cofiring gas at low load can avoid this.

6.2.3 Addition of natural gas for reburning

Reburning technology was originally developed for NOx combustion control, primarily on coal-fired furnaces. It is a staged fuel approach that uses the entire volume of a furnace, rather than the control of NOx production/destruction within the flame envelope. Reburn is a three-stage combustion process that takes place in primary, reburn and burnout zones. In the primary zone, pulverised coal is fired through conventional or low-NOx burners operating at low excess air. A second fuel injection is made in a region of the boiler after the coal combustion, creating a fuel-rich reaction zone (the reburn zone). Here reactive radical species are produced from the natural gas that react chemically with the NOx produced in the primary zone, reducing it to molecular nitrogen. The partial combustion of the natural gas in this reburn zone results in high levels of CO. A final addition of overfire air, creating the burnout zone, completes the overall combustion process.

In practice, the technique usually involves the splitting of the boiler's combustion zone by installing a second level of burners above the primary combustion zone. Typically, up to 25% of the total heat input is injected into this reburn zone, creating fuel-rich conditions in the region of primary combustion. Within the reburn zone, NOx formed in the combustion zone is partially reduced to elemental nitrogen. The formation of additional NOx is limited due to the lower oxygen concentrations and lower combustion temperature in the reburn zone. Most coal-fired power plants that have deployed reburn systems use natural gas as the reburn fuel. Although other fuels have been used for reburning, gas usually provides the greatest NOx reduction performance as it is easy to inject and control, and does not contain any fuel-nitrogen. Natural gas reburn can reduce NOx emissions by up to 70%.

Some technological advances have increased the effectiveness of reburning, such as dual-fuel orifice cofiring technology. Alongside this, Breen Energy Solutions has also developed a system known as fuel lean gas reburning (FLGR). This differs from conventional gas reburning systems as the gas is injected such that it optimises the furnace's stoichiometry on a highly-localised basis, thus avoiding the creation of a fuel-rich zone and maintaining overall fuel-lean conditions. Gas injection is carried out at a low furnace temperature (between 1090°C and 1260°C) using multiple, high-velocity turbulent gas jets that penetrate the upper furnace to the areas with the highest NOx concentration. FLGR technology is claimed to be less expensive than conventional reburning, and has been installed on units with no NOx controls, low-NOx burners (with and without overfire air) and selective non-catalytic (SNCR) equipment, mostly in the USA (Liss, 2016).

Reburning systems can provide a means for incorporating a sizeable amount of natural gas into an existing coal-fired power plant, thus providing a number of environmental and operational benefits.

6.3 Sources of gas

If adequate supplies are available within an acceptable distance and transport costs are not prohibitive, any of the following forms of gas could potentially be used for cofiring.

6.3.1 Conventional pipeline natural gas

Major gas producers include the USA, Russia, Iran, Qatar, Canada, China, Indonesia and the Netherlands. Not all of these countries have significant coal industries, but major countries with both gas and coal reserves include the USA, China, Indonesia and Russia. Each has abundant resources of both, although not necessarily near each other. Recent years have seen the global consumption of natural gas increase steadily and forecasts suggest that this trend is set to continue. The IEA International Energy Outlook (2016) projects that by 2040, gas consumption will have nearly doubled from the 2012 level, based on its Reference Case scenario.

In some countries, natural gas is used extensively for power generation. The world's largest individual plant is thought to be the 5.6 GW Surgutskaya GRES-2 power plant in Russia. Globally, conventionally-produced natural gas will continue to be one of the main forms of gas available for cofiring and power generation in general.

6.3.2 Shale gas

The shale gas industry has developed rapidly. Shale gas is essentially the same as conventional natural gas, although produced by different means. For the past decade, its production has been dominated by the USA, although new discoveries are being made and development is increasing in other parts of the world. Global shale gas is expected to grow by 5.6%/y in the near term, well in excess of the growth of total gas production (BP, 2016). As a result, the share of shale gas in global gas production is forecast to more than double from 11% in 2014 to 24% by 2035. Increased production outside North America is expected to come mainly from the Asia-Pacific region, particularly China. However, production will also continue to increase in the USA, with shale gas predicted to account for ~75% of total US gas production in 2035 and almost 20% of global output. Over the past decade, the development of horizontal drilling and hydraulic fracturing technologies has made it possible to develop US shale gas resources, contributing to a near doubling of estimates for total technically recoverable natural gas resources.

6.3.3 Liquefied natural gas (LNG)

LNG plays an important role in the power generation sector of some countries, despite the often considerable transport distances involved. Its future role is expected to increase further as global production and consumption rise (BP, 2016). A significant increase is expected to occur over the next five years as a series of ongoing projects come to fruition. Forecasts suggest that globally, by 2035, LNG could surpass pipeline imports as the dominant form of traded gas. The US is likely to become a net exporter of gas later this decade, while the dependence of Europe and China on imported gas is projected to increase. World LNG trade could more than double by 2040 (EIA, 2016). Most of the increase in liquefaction capacity will occur in Australia and North America, where numerous new liquefaction projects are planned or under construction – many of these will become operational within the next decade.

A number of major economies depend on imported LNG to provide fuel to at least part of their power sectors. Japan is the world's largest LNG importer and has several major power plants fired on LNG. These include the 5.04 GW Futtse plant that is supplied via an underwater pipeline from a nearby LNG terminal with the capacity to handle 9 Mt/y. Other power plants include the Kawagoe power station (4.8 GW), and the Chita thermal power station (4 GW). Japanese LNG imports have risen significantly in recent years. Other major LNG importers include Taiwan and South Korea; both use LNG in their respective power sectors.

In some parts of the world, LNG could potentially replace conventional pipeline gas as a source of fuel for cofiring applications.

6.3.4 Landfill gas

Landfill gas is formed from the anaerobic decomposition of organic materials deposited in landfills. Typically, it comprises ~50% methane, with the balance being a mixture of CO_2, nitrogen, and various volatile compounds. Clearly, possible application is limited to locations that host major landfill sites, capable of producing an adequate supply of landfill gas. Historically, where collected, much landfill gas has been used to power reciprocating engines of various types, or burned in small scale cogeneration plants. Where reliably available in adequate amounts, it can also be cofired in conventional coal-fired power plants; technical modifications to accommodate this can be minimal.

Within the scope of the present report, a successful cofiring project would require an existing coal-fired power plant, access to a locally-sourced supply of landfill gas, and probably, a supply of natural gas to overcome fluctuations in the supply of landfill gas. Thus, there is currently only limited cofiring of landfill gas. However, there are a few such plants. In the USA, two coal-fired units of the Stanton Energy Center in Florida have been converted to cofire natural gas. They also have the capability of cofiring landfill gas, delivered by an 8 km pipeline from the Orange County Landfill. Landfill gas provides up to 22 MWe of additional power, enough to displace up to 3% of the fossil fuel consumed by the boilers. It is cofired with coal in both full load and low load operations.

6.3.5 Coalbed methane (CBM) and coal mine methane (CMM)

CBM refers to methane present in coal seams, formed as the original plant material slowly transforms into coal. CMM is methane released from the coal and surrounding rock strata as a result of mining activities – it is generally a mixture of methane (ranging from 25–60%) and air in varying proportions. For safety reasons, CMM is usually vented.

CBM is a useful source of energy used increasingly in the USA, Australia and China. Unlike much natural gas from conventional reservoirs, it contains few heavier hydrocarbons such as propane or butane and no natural gas condensate, although it often contains up to a few per cent CO_2. National CBM resources can be considerable although there is often a degree of uncertainty over confirmed levels (Table 8).

In some countries with significant coal mining sectors, CBM production can provide a reliable energy stream. For example, in the USA, CBM accounts for ~5% of total yearly US natural gas production. The amount of methane emitted from coal mines can be significant. In 2014, US mines emitted ~67 Mt CO_{2eq}. Globally, methane emissions from coal mines are forecast to reach nearly 800 Mt CO_{2eq}, around 9% of total global methane emissions. China will generate the greatest amount of CMM (>420 Mt CO_{2eq}/y by 2020), or more than 27 billion m^3/y. Other leading global emitters include Russia, Australia, Ukraine, Kazakhstan, and India.

Table 8 Global coalbed methane resources (Tyler, 2015)

Country	Billion m^3
China	30,015–35,112
USA	16,990–25,485
Canada	5,663–76,455
Australia	8,495–14,158
Germany	2,830
UK	1,700
Kazakhstan	1,130
Poland	2,830
India	850
South Africa	850
Ukraine	1,700
Global total	84,384–262,214

Both CBM and CMM are utilised. Globally, most is used for various types of power generation although other applications can include district heating, boiler fuel, town gas, injection into the natural gas pipeline systems, coal drying, firing in gas engines, and as a supplementary boiler fuel. There are an estimated 200 operating recovery and utilisation projects in ~14 countries, plus a significant number of others in development. Around 100 of these are used for small scale power generation (Tyler, 2015). Most such capacity is in the USA, China, Europe and Australia. Around the world, various new projects are being developed. For example, at Majuba in South Africa, prospecting for CBM is underway by Australian company Kinetico partnered with Badimo Gas. CBM is being considered as a cofiring fuel for the Majuba coal-fired power plant.

Depending on individual circumstances, at least some CBM could probably be cofired in existing large-scale coal-fired power plants, particularly where these are sited at minemouth locations. In such cases, transport requirements for the recovered gas would be minimal (Sloss, 2015).

6.3.6 Underground coal gasification (UCG)

For several decades, UCG has been suggested as an effective means of utilising coal that is inaccessible or uneconomic to mine using conventional techniques. Potential advantages cited have included enhanced security of energy supply, flexibility, lower cost than some competing technologies, modularity of the technology, short lead time, and overall cost-effectiveness.

Historically, development and subsequent application (at least to pilot scale) has taken place in several parts of the former Soviet Union, Uzbekistan, China and Australia. Results have been mixed. Reportedly, one project is still operating under 'commercial' conditions – this is Linc Energy's Yerostigaz UCG plant in Angren, Uzbekistan. This has been operating since 1961, producing 1 million m^3/d of syngas from coal reserves. This is used for electricity generation in a unit of the nearby coal-fired Angren Power Station in Dzhuma-Angren (Linc Energy, 2017).

In 2007, Eskom of South Africa commissioned a 5000 m^3/h pilot plant on the Majuba coalfield. UCG gas was produced from ~100 t/d of coal and fed to the nearby Majuba coal-fired power plant where it was cofired via a single burner in one of the plant's units (Figure 11). Later, the gas was flared. It was originally intended that the technology would be ramped up to 75,000 m^3/h to cofire the plant alongside coal. However, the project closed down in 2015.

Elsewhere, China continues to research UCG, and pilot-scale projects have been undertaken in Inner Mongolia at sites such as the Gonggou mine, Wulanchabu City, and the Meiguiying mine. India and Pakistan have also carried out initial tests and identified sites for exploitation. In Europe, most activity has been taking place in Poland and Ukraine, with feasibility studies also being carried out in Bulgaria (Couch, 2009).

Figure 11 The Majuba coal-fired power plant in South Africa (photograph courtesy of Eskom)

6.4 Advantages and disadvantages of cofiring

6.4.1 Advantages

Natural gas cofiring can provide benefits that include:

Adaptation of existing infrastructure and control systems

Many coal-fired power stations already employ natural gas as a start-up or back-up fuel, so the necessary infrastructure and control systems for feeding gas to the boiler may already be in place. Depending on the circumstances and plant requirements, a switch to cofiring (or dual fuel capability) can entail only modest capital expenditure, although if new waterwall penetrations are required, the capital costs and complexity of the project can increase significantly. However, gas igniters and warm-up guns can often be merely upsized in place. This can yield as much as 20–25% of total heat input to the steam generator.

Provided that the existing gas pipeline is of sufficient size, few fuel handling system modifications may be required to adopt cofiring. Studies by Black & Veatch suggest that capital costs for implementing gas cofiring, excluding pipeline-associated costs, can range from US$10,000–100,000 per megawatt (Nowling, 2016).

Enhanced fuel flexibility

Cofiring removes total reliance on a single source of fuel, so creating fuel flexibility. Thus, if a problem arises with availability of one fuel, the plant has the ability to maintain operations by switching to the other. Similarly, increases in the price of either fuel can be countered by changing the cofiring ratio such that the cheaper fuel predominates. Potentially, any suitable type of gas can be cofired. Possible opportunities can include:

- the use of lower-cost coals may become a viable option, without the risk of lost capacity;
- plants supplied with coal of variable quality, or suffer from poor or erratic blending practices, can capitalise on cofiring. If excessive amounts of poor quality coal are fed to the plant, capacity can be restored by increasing the amount of gas burned;
- unexpected outages of plant equipment such as coal mills can be hedged by having natural gas available to make up lost load;
- coal inventory levels can be reduced. Should coal unexpectedly become unavailable, gas use can be maximised to replace it, and vice versa; and
- some emissions control retrofits may be reduced in scope, delayed, or avoided, depending on the coal quality, level of gas cofiring intended, and the regulatory environment.

Improved operational flexibility

Cofiring with natural gas can reduce warm-up times, allowing the unit to be brought on line faster than an unmodified equivalent, as well as enabling faster unit ramp-up. A faster start-up helps minimise higher emissions sometimes experienced during this phase. With some plants in the USA, this allows compliance with the federal Mercury and Air Toxins Standards (MATS) (Sznajderman, 2017).

Cofiring can also provide a significant reduction in the minimum unit load achievable, an important factor for many coal-fired power plants. By cofiring a significant amount of gas when in low load conditions, the minimum operating temperature of the plant's SCR unit (where fitted) can be maintained. In addition, in some countries, utilities may be required to maintain multiple coal pulverisers in service. Cofiring can reduce this need.

Cost savings

Potentially, cost savings could be achieved in a number of ways:

- switching wholly or partially between coal and gas will allow use of whichever is cheaper at the time;
- cofiring may allow use of cheaper coal of lower quality and cost. The addition of gas can ensure unit capacity is maintained, maximising plant revenue;
- replacement of at least part of the plant's coal feed with gas means less coal throughput, reducing wear and tear on major items such as pulverisers and coal handling systems; and
- less coal throughput reduces operation and maintenance (O&M) costs. For example, boiler slagging and fouling can be reduced significantly with even modest levels of natural gas cofiring. In addition, erosion and corrosion will decrease throughout the unit as gas heat input increases, most significantly within the steam generator itself. Coal mills, ash handling systems, flue gas ductwork, and emissions equipment wear will be reduced, as will corrosion resulting from sulphur, chlorine, and alkali metals. Coal mill loading and duty cycles can also be decreased, which is especially useful for coal-fired units that are currently mill-limited or have frequent mill maintenance outages.

Environmental aspects

Reduced coal use will impact positively on plant emission levels and associated waste streams. Thus, bottom ash, fly ash, FGD scrubber sludge or gypsum, mill rejects, and various other waste products will be reduced as well as handling and disposal costs.

Emissions to air will be proportionately lower, depending on the level of cofiring taking place. O&M costs of environmental control systems such as FGD and SCR units, and ESP or bag filters are likely to be lower. In the case of SCR systems, ammonia use will be less and extended catalyst life is likely. Where mercury control systems are in place, less activated carbon will be required.

6.4.2 Disadvantages

An obvious requirement is that the coal-fired plant has an adequate source of natural gas available at an acceptable price. If the plant already uses gas for warm-up operations, existing infrastructure may be adequate. If not, additional supply and control equipment may be required. Depending on the overall length and any local constraints, costs for a new gas pipeline can be considerable.

A major attraction often cited for cofiring is the low price of natural gas. Although this is currently the case in the USA, gas may be much more expensive and less readily available in other economies. Even in the USA, there are concerns that gas prices could increase significantly in the future as political and environmental pressures on hydraulic fracturing and investments in gas export facilities could drive the price of natural gas upwards, closer to those seen in Europe (R-V Industries, 2016). Higher gas prices could cancel out any advantages and cost savings provided by cofiring.

In the USA, the EPA has suggested that under some circumstances, cofiring could be an alternative to applying partial carbon capture and storage to coal-fired power plants. The EPA has advised that new emissions standards could be met by cofiring ~40% natural gas in new, highly efficient supercritical pulverised coal power plants. However, not all industry observers agree with this concept and argue that cofiring in this manner is still an 'emerging' technology. Some are of the opinion that cofiring up to 40% natural gas would require the boiler to be specifically designed for that capability and that cofiring at this level has not been adequately demonstrated. They feel that it is not yet a practical option in setting limits for new coal plants and that the technique is not a viable option when considering new emission compliance limits. It is suggested that for some coal-fired plants to meet proposed future emission limits, operators would probably need to fire even more than 40% natural gas in order to comply with EPA's final standards (Nowak and others, 2015). However, an opposing view is taken by others within the industry, some of whom are actively promoting the uptake of cofiring. For example, in West Virginia, there is support for cofiring as an option to keep some coal-fired plants operating, as well as its use in new-build cofiring plants (Volcovici, 2015).

Various technical issues will need to be considered when a switch to cofiring is contemplated. These include:

- due to the high hydrogen content of natural gas (~25% mass), latent heat losses resulting from the production of water during the combustion process can be much higher than for all but the wettest coals;
- differences in the flame temperature, gas mass flow, soot and ash reflectivity, and slag levels on boiler waterwalls can result in heat transfer imbalances throughout the steam generator;
- in some locations, supply restrictions may limit the maximum level of gas available. Furthermore, seasonal restrictions may apply, giving priority to other applications such as home heating;
- a major risk associated with cofiring is often poor natural gas burner placement – if not located appropriately, it can result in excessive temperatures or incomplete combustion in certain areas (Reinhart and others, 2012); and
- there can be significant impacts on heat transfer in the boiler between coal and gas. In some cases, original heat transfer surfaces may be inadequate for full natural gas firing. The heat transfer characteristics for natural gas versus coal vary significantly – coal has more radiant heat transfer and gas has more convective. If modifications are not made to the existing heat transfer surfaces or alternative operating conditions identified, problems with metallurgy can arise and major plant components run the risk of becoming unreliable. It can be expensive to make significant changes to boiler heat transfer surfaces. Overcoming this requires evaluation across the complete spectrum of load dispatch and cycling scenarios (Gossard, 2015).

6.5 Future prospects for cofiring

As already noted, there are many coal-fired power plants that already use natural gas in some way, either for plant start-ups or warming, reburning for NOx control, or cofiring with coal. But many only use low-moderate levels of gas addition, with only a limited number currently cofiring significant amounts. However, potentially, a sizeable number of such plants could cofire natural gas in greater quantity.

Coal-fired power plants that have a gas supply and use it regularly as part of plant operations are present in many countries. The largest numbers are in the USA where ~27 GW of coal-fired capacity uses gas in varying amounts. This is followed by Ukraine (with ~20 GW of capacity) and Russia (with ~12.5 GW) (Platts, 2017). Many other countries operate more modest numbers of coal-fired plants, some with the potential for cofiring; major ones are shown in Table 9. The technology could also be an option in counties with smaller coal-fired fleets – for example, selected plants in Australia, Kyrgyzstan, Poland, Slovakia, Bulgaria, and Thailand.

Table 9 Largest fleets of coal-fired power plants that also use natural gas (Platts, 2017)

Country	Capacity (MW)	Main fuel type(s)*	Plant types
USA	27,071	bituminous, subbituminous, lignite	subcritical, supercritical
Ukraine	20,740	bituminous, subbituminous	subcritical, supercritical
Russia	12,396	bituminous, subbituminous, lignite	subcritical, supercritical
Romania	3525	lignite, bituminous	subcritical
Germany	3508	lignite, bituminous	subcritical, supercritical
Indonesia	3400	subbituminous	subcritical
China	3175	bituminous, subbituminous, lignite	subcritical, supercritical
Netherlands	2360	bituminous	subcritical, supercritical
Uzbekistan	2100l	lignite	subcritical, supercritical
Turkey	1600	bituminous	subcritical, supercritical
Malaysia	1600	bituminous	subcritical
Moldova	1600	bituminous	subcritical
Italy	1465	bituminous	subcritical, supercritical
India	1400	bituminous	subcritical
Czech Republic	1115	bituminous, lignite	subcritical
Israel	1150	bituminous	subcritical

Much of the interest in cofiring has so far come from the American power sector. However, despite the added flexibility and relatively low cost of converting some coal plants to cofiring or full dual-fuel capabilities, some US utilities remain hesitant. Faced with continued pressure from the EPA, many small and medium coal plants face economic uncertainty. The main options available appear to be to invest in expensive systems needed to comply with stricter NOx, SO_2 and mercury limits, to operate on a limited basis as and when demand dictates, or closure (Breen Energy Solutions, 2014). The degree of uncertainty that remains over future government policies and the environmental landscape means that many utilities are reluctant to invest in their coal-fired facilities.

Although estimates vary, most agree that in the coming years, in the highly competitive marketplace, a considerable tranche of coal-fired US power plants face possible closure. This trend is already under way, with a growing number of (mostly older) plants shuttered in recent years. However, based on assessments undertaken by major US power plant technology suppliers (such as Black & Veatch) it seems feasible that some of these plants could adopt cofiring, allowing them to meet upcoming environmental regulations and therefore extending their working lives. Industry opinion is that in the future, operating advantages are likely to go to utilities with diversified fleets – those with the ability to switch between fuels – cofired plants could form an important component of this. Enhanced fuel flexibility is one possible route towards continued viability and, as demonstrated by several US utilities (*see below*), is being actively pursued. The current low price of natural gas in the USA will continue to be a major factor in any such equation. And clearly, replacement of any part of a plant's coal feed will lead to lower emissions and the production of less solid wastes.

US utility FirstEnergy Corporation considers that cofiring would provide benefits such as fuel diversity, lower plant emissions, and easier compliance with future federal and state environmental regulations. The company feels it could be a viable cost-effective option that will allow their plants to continue producing low cost electricity. As part of a review of future corporate strategy, FirstEnergy is exploring the possible retrofit of some existing coal-fired units, enabling them to cofire natural gas.

Enhanced fuel diversity, improved operational flexibility, and reduced emissions are also cited as important factors in the success of Orlando Utilities Commission's (OUC) Stanton plant that regularly cofires. Air sampling has shown that Stanton's emissions are among the lowest of any coal-fired plant in the USA. OUC considers that building sufficient flexibility into its generation capacity portfolio will be critical in adapting to changing market conditions. Fuel diversity is an important aspect of this strategy. For example, in 2008, the price of natural gas in the USA reached historically high levels, so coal was used to produce 78% of the company's electricity and gas produced 13%. However, as gas prices fell, the situation reversed – in 2013, gas produced 46% and coal 29%, a reflection of the changing market conditions.

6.5.1 The impact of gas prices

Cofiring could provide a viable lifeline to at least some US power plants currently at risk of premature closure. But what are the prospects beyond North America? When a utility considers cofiring, the most important factor is likely to be the cost of the gas supply needed. For some years, gas prices in the USA have been at historically low levels. Despite several temporary spikes in 2005 and 2009, prices have since remained predominantly below US$5 for 1 million Btu (or 1055 MJ). In 2015, the average wholesale US gas price was ~US$2.5 (EPA, 2017). At the same time, prices in, for example, Ukraine, were ~9.5, and in China, they were ~9.7. The highest gas prices were in South Korea, Japan and Taiwan, countries that rely heavily on imported supplies of LNG. Prices were also relatively high in India. However, those in Indonesia were lower at ~US$5.4. Indonesia is one of the most important natural gas producers and the largest gas exporter in the ASEAN region. Gas consumption has been increasing steadily, with the power generation sector expected to be the main driver of growth in the coming decades – around 60 GW of new power capacity will be added during the next decade (IEA Indonesia, 2014). As elsewhere, some coal-fired plants use natural gas for start-up operations, although in a number, it is also used in greater amounts. For example, to capitalise on the modest gas price and increase fuel flexibility, the newest unit of the 4 GW Suralaya power plant was built so that it could fire combinations of coal with natural gas, as well as heavy fuel oil and biomass. Thus, over-dependence on a single source of fuel has been effectively eliminated.

Gas prices were similar in Malaysia, where four units (2 x 300 MW and 2 x 500 MW) of the country's biggest power plant, the 2.42 GW Sultan plant, are capable of cofiring coal with natural gas and/or bunker oil. This is the only plant in Malaysia capable of triple fuel firing, although given the country's modest gas price, there are several others that could probably do likewise. In northwest European countries, prices have been somewhat less than the rest of Europe, but consistently higher than in North America.

As well as the price of gas, there are likely to be locations where environmental pressures, the need for enhanced fuel flexibility, or reduced operational costs may take precedence. As such, the potential for a switch to cofiring is likely to be site-specific and depend on a number of economic and environmental factors. Where gas is used in relatively small amounts, the cost may be too high for larger-scale use.

Even within a country, the situation can differ, depending on the availability of gas in a specific region. For example, in Ukraine, many plants burn hard coal but use gas for start-up operations. Several major power plants also cofire coal and gas although others are too remote from an affordable gas supply. However, since 1984, all units at the Zaporizka thermal power plant have been cofiring despite the high price of gas in the country. Advantages cited include higher operational efficiency and lower plant air emissions and solid wastes. However, high gas prices are a major factor in restricting its greater use for cofiring within the country.

In India, prices tend to fall roughly in the middle, with average costs typically ~US$8 for 1 million Btu. Although not as expensive as some other countries, its use is limited through a combination of lack of availability in some states, coupled with affordability. In India, there are two forms of natural gas available, namely domestically produced supplies and imported LNG. LNG plays a critical role in partially bridging India's gas supply gap; the country is currently the world's fourth largest importer behind Japan, South Korea and China. There is a strong regional imbalance with regard to access to gas. A few states such as Gujarat, Maharashtra and Uttar Pradesh consume more that 65% of the available gas, while most others lack access. This imbalance results mainly from a lack of pipeline infrastructure in many states such as West Bengal, Bihar, Jharkhand, Odisha and Chhattisgarh (PHD Chamber of Commerce and Industry, 2014). Recent falls in domestic gas production and the affordability of imported LNG in the power sector has resulted in many gas-based power plants remaining under-utilised. For example, in the latter part of 2016, only ~27–28% of the gas from domestic supplies and allocated for power generation purposes was available (Economic Times of India, 2017). This highlights the problem for Indian gas-fired generation in general. As the supply from indigenous sources is limited, some producers may opt for imported LNG. However, this makes the cost of electricity uncompetitive, particularly with that from coal. As a consequence of the present lack of availability in many states, opportunities for coal-gas cofiring are limited to regions that have affordable and reliable gas supplies. Shortage of gas within the country remains a major issue.

To summarise, natural gas cofiring has provided utilities with combinations of financial, environmental and operational advantages. However, a crucial requirement is a reliable affordable supply of natural gas. In countries such as the USA, where low priced natural gas is available in abundance, cofiring may extend the working lives of at least some coal-fired power plants otherwise faced with premature closure. The sector is watching the ongoing development of the current tranche of cofired plants with interest, and success here would likely lead to replication of the technology.

6.6 Examples of cofiring projects

Within the context of this report, a cofired unit is one that is generally considered to be capable of burning two or more fuels simultaneously to meet load. A dual-switching unit is one that can replace one fuel type completely with another. The concept of firing steam power plants on various combinations of coal and natural gas is not new and there are applications already in service (Kislear, 2016). Recently, particularly in North America, interest in combining the use of both fuels has increased.

During the earlier part of the present decade, a number of US utilities first considered the idea of cofiring. At the time, the US economy was depressed and consequently, electricity demand was characterised by sizable fluctuations meaning that coal-fired plants were often forced to operate at very low load. Cofiring was seen as a means of allowing more efficient operation, especially as more stringent emission legislation was being introduced. However, interest from some utilities subsequently waned and various proposed projects were shelved. Despite this, a number of plants have since been converted or are in the process of conversion. Feasibility studies are ongoing for a number of others. Some utilities consider that cofiring remains a viable option.

6.6.1 USA

Against the background of low gas prices, there has been an increase in the amount of gas cofired, although not as dramatically as might be expected. Many US coal-fired power plants already use gas but not necessarily as a main fuel. Some units are incapable of burning natural gas alone and limit its use mainly to plant start-ups. As a result, some of the increase in gas burn can be attributed not to a changeover from coal to natural gas, but rather to a switch from fuel oil during periods of start-up. However, many US power plants have moved away from steady-state base load operation to frequent cycling and load following. This entails more periods of low load and plant start-ups which increases the amount of start-up fuel burned.

Some US coal plants can accommodate higher levels of cofiring gas. An industry survey of 2012 identified plants that had the capability of cofiring at a significant level. Although the situation concerning US coal-fired power generation in general has since continued to evolve, it provided some interesting data. Nearly 200 individual plants with a combined capacity of ~78.5 GW were identified. These were units that had fired coal and gas together for electricity generation during at least one month in the previous few years. During the period 2008-11, the volume of gas burned by these plants increased by 11% whilst the amount of coal burned fell 9% (Hameed, 2012).

When broken down on a regional basis, the North American Electric Reliability Corporation region had 55 plants (total of 24.1 GW) that had cofired. When looked at via regional transmission organisations, Midcontinent Independent System Operator had the most cofiring plants (76, with a total of ~21.3 GW), followed by PJM (32 plants, ~14.9 GW), then CAISO (4 plants, ~2.75 GW).

The top twenty plants that had cofired accounted for ~40% of the total operating capacity. Individual plants included Alabama Power/PowerSouth Energy Cooperative's 2.74 GW James H Miller Jr station, the largest US power plant burning both fuels. Operated by Arizona Public Service Co, the 2.1 GW Four Corners plant in New Mexico was the second largest, followed by the Harrison power plant, owned by Allegheny Energy Supply Company and Monongahela Power. In 2011, the Harrison plant's three units burned 4.6 Mt of coal, down 18% compared to the level in 2008. Gas consumption increased 34% over the same period.

Industry interest in cofiring has continued. In 2016, **Talen Energy** completed a feasibility study on the provision of natural gas to its 1500 MW coal-fired Montour power plant and the installing boiler modifications to enable cofiring. The modified plant will be capable of operating on coal, natural gas or combinations of both. Engineering and design work is now under way and, assuming that all necessary permitting and regulatory approval is obtained, the anticipated completion date is the second quarter of 2018. A 24-km pipeline will bring gas to the site. The estimated capital expenditure for plant modifications is ~US$70 million plus additional pipeline expenses. Fortuitously, the Montour plant is located close to the Marcellus Shale, one of the largest natural gas formations in the world.

Talen Energy is also in the process of adding gas generating capacity to its Brunner Island coal-fired plant at the cost of US$100 million. Conversion could be completed by the end of 2017. The main aims are to make the plant more sustainable on both a financial and regulatory basis. Importantly, cofiring will ensure that plant emissions will be reduced. However, the main driver will be the fuel cost – the cheaper fuel at the time will be used. Talen has announced that it also expects to add gas-fired capabilities to other plants in its fleet. Other plant operators are doing likewise. For example, **Duke Energy Carolinas** is adding Dual Fuel Optionality (DFO) at its coal-fired Rogers Energy Complex in Mooresboro, North Carolina (formerly the Cliffside facility). This comprises one older 552 MW subcritical coal-fired unit (Unit 5) and the relatively new coal-fired 844 MW supercritical Unit 6 (Figure 12). Four other coal units were retired earlier this decade as part of an air permitting deal that allowed Unit 6 to be built. The DFO option will allow up to 100% natural gas cofiring on Unit 6 and 10% cofiring on Unit 5. Duke expects the project to reduce O&M costs, provide enhanced fuel and operational flexibility, and lower emissions. When operating solely on gas, CO_2 emissions will be 40% lower, and mercury and SO_2 emissions will virtually be eliminated. Ash production will also be reduced (Cassell, 2016). Clearly, in practice, the reductions achieved will depend on the ratio of coal:gas used at the time.

Figure 12 The Rogers Energy Complex in Mooresboro, North Carolina (photograph courtesy of Duke Energy)

Duke Energy completed Phase 1 engineering of the Rogers Energy Complex project in July 2016. Modifications to Units 5 and 6 included burner and ignitor alterations, additional gas piping and control systems, and logic changes. The project is scheduled to be completed by 2019, at an estimated cost of US$56 million. Duke considers that in the longer term, the flexibility provided by cofiring will help hedge against future coal and gas cost uncertainties; it will provide the ability to maximise benefit from short-term (daily and weekly) fuel price variability. An additional bonus is that as Unit 5 will be capable of 10% cofiring, it will allow the use of lower cost coal blends and will also significantly reduce fuel oil utilisation as unit start-up will be achieved using gas. The Charlotte-based utility says it is looking at the possibility of similar modifications at other coal plants. Candidates include the 770 MW Mayo Steam Electric Plant and the 2.24 GW Belews Creek Steam Station.

In Florida, the **Orlando Utilities Commission** (OUC) has converted two coal-fired units (Units 1 and 2) at its Stanton Energy Center to cofire natural gas with the main aim of increasing fuel diversity. As well as fuel price, an important factor has been increased cycling. A key element of the switch to cofiring has involved equipping the two coal-fired boilers with igniter systems that can accommodate various fuel firing configurations. OUC considers that it can capitalise on fluctuations in the price and availability of coal and gas. As well as cofiring natural gas, both units can also cofire landfill gas. This provides up to 22 MW of additional power, enough to displace up to 3% of the fossil fuel consumed by the boilers. Landfill gas is cofired with coal in both full and low load operations.

Due to low natural gas prices and environmental concerns associated with coal use, OUC has focused on reducing the amount of coal burned at Stanton. Both 450 MW coal-fired units are regularly cycled to reduce load. During periods of high demand, each unit operates five pulveriser mills although at night, only a single mill remains in operation, reducing generation to 90–120 MW. Each unit has 30 pulverised coal burners arranged in five rows with six burners per row – each incorporates a natural gas fuel gun and diffuser. Gas guns are ignited by a retractable high energy spark igniter (HESI). It is moved into firing position for ignition, warm-up and stabilisation, then retracted when not in service. However, to capitalise on low natural gas prices and to reduce coal consumption, Units 1 and 2 can operate with the gas igniters in continual full-time service. Cofiring with gas during low-load operation provides ~50% of the heat input, thus reducing coal consumption (Parent and Czarniecki, 2016). Historically, annual coal consumption has dropped, whilst the use of gas has increased.

Other utilities continue to consider the option of cofiring. For example, **FirstEnergy Corporation** is assessing the possible retrofit of some of Mon Power's existing coal-fired units in West Virginia that could be modified to cofire up to 30% gas. The company may ask the West Virginia Public Service Commission for approval to cofire at some point in the future (Silverstein, 2016).

FirstEnergy had previously announced that it was considering cofiring at a number of other plants including several in Pennsylvania such as Hatfield's Ferry (1.71 GW), the Bruce Mansfield Plant (2.94 GW), the Mitchell Power Station (370 MW), and Pleasant Power Station (1.3 GW). The Hatfield's Ferry plant is located close to a major natural gas pipeline, the Texas Eastern Transmission line. FirstEnergy estimated that each mile of pipeline needed to supply the plant would cost between US$2 and US$5 million to construct and noted that the price of gas must continue to stay low for any project to be considered viable. However, subsequent events have changed the company's plans. Had the cofiring option been pursued, new dual-fuel boilers would have been installed, capable of burning between 25% and 40% gas. However, since 2011, FirstEnergy has closed eleven plants across Appalachia, including Hatfield's Ferry, shuttered in October 2013, although recent moves have seen possible plans for re-opening, with the plant coming back on the grid in 2019. FirstEnergy is currently undertaking an engineering study to revisit the option of retrofitting Hatfield's Ferry to burn natural gas along with coal. It is also studying restarting it as a coal plant or converting it entirely to gas.

Much of the focus on cofiring has been on older coal-fired plants. However, it may also be an option for some newer more advanced units. Such has been the case with 700 MW supercritical Longview pulverised coal fired power plant in West Virginia, considered to be one of the most efficient in the USA. It is operated by **Longview Power**. In April 2016, the company announced that, since a restart in November 2015, the plant had completed 155 days of operation – during this period it had averaged 39% efficiency, with a capacity factor of 96% and availability of 98.5%. During this period, Longview took advantage of historically low natural gas prices by cofiring up to 20% of unit heat input. No additional investment was needed to achieve this. Coal burned is run-of-mine, used without preparation (Modern Power Systems, 2016). In addition, the plant made use of a large capacity mobile LNG facility, installed to ensure that gas supply remained available for start-up and significant load changes when pipeline natural gas supplies were curtailed; for example, during cold weather, when residential and key industrial users took precedence, or during gas line infrastructure curtailments. The LNG facility provides Longview with full 'inside-the-fence' start-up reliability during peak winter seasons.

In Alabama, the Gaston Steam Electric Generating Plant (Figure 13) is operated by **Alabama Power Corporation**. Four coal-fired units have been converted to natural gas firing. However, in Spring 2016, Alabama Power completed a project that gave Unit 5 the ability to start up with natural gas, as well as cofire gas with coal. It can fire gas-only up to two-thirds of the unit's capacity. Under normal conditions, coal will continue as the unit's primary fuel. The cofiring project included associated gas-related equipment, unit piping, valving, and appropriate monitoring equipment to ensure safe natural gas combustion and operation.

Figure 13 The Gaston Steam Electric Generating Plant (photograph courtesy of Alabama Power)

Some major equipment suppliers have been active in converting coal-fired boilers to cofiring. For example, Riley Power Inc (RPI) demonstrated the successful retrofitting of four utility boilers to fire coal or gas at the original steam flow capacity requirements, with acceptable emissions and boiler thermal performance. One plant comprised an RPI Turbo-style boiler equipped with twelve directional flame burners that received pulverised coal from three ball tube mills. Pressure part modifications were not required to accommodate the gas firing.

A second RPI boiler was of the opposed wall-fired furnace type located in the southeast USA. It was a single-stage reheat, natural circulation steam generator that had 24 low NOx burners firing bituminous coal. These included the capability to fire full load gas on each burner. The full load gas firing capabilities were never commissioned when the burners were originally installed. However, the economics of coal versus natural gas encouraged the utility to investigate both fuels. A feasibility study reviewed the combustion requirements needed to ensure safe reliable operation on both natural gas and coal (or combinations of both) (Courtemanche and Penterson, 2012). The company concluded that the variability in the price of natural gas presented some opportunities. RPI noted that when the price of natural gas exceeded ~US$6 per 1000 cubic feet (or ~US$6 per 28,317 m^3) complete conversion to gas alone was not economically feasible. In December 2016, gas prices were around US$4.3 per 1000 cubic feet.

The approach of adding gas firing capability to an existing coal boiler can provide a utility with more flexibility to react to gas price fluctuations. It is considered that at least some of the aging coal-fired US fleet could be successfully retrofitted to fire both fuels and that utilities should seriously consider cofiring as opposed to a complete 100% natural gas conversion. This approach would provide the utility with the flexibility to switch back and forth between coal and natural gas, depending on the price of each, whilst maintaining environmentally acceptable emissions performance.

6.6.2 Other cofiring projects

There are numerous conventional coal-fired power plants around the world that have the capability of firing natural gas alongside coal. However, under normal operating conditions, most rely on coal as their main fuel. Gas is used primarily for plant start-ups and possibly as back-up fuel, although it may also be deployed under exceptional circumstances – for instance, to compensate temporarily for coal-related issues. However, depending on local circumstances, significantly greater use of gas may simply be uneconomic, or supply restricted.

In the Asia-Pacific region, various coal-fired power plants report natural gas as an 'alternative' fuel, although, in reality, most rely mainly on coal. However, there are a number that have the capability of cofiring natural gas and do so on a regular basis. For example, the newest unit of the 4 GW Suralaya power plant on the island of Java is Indonesia's largest coal-fired power plant and uses subbituminous coal as its main source of fuel (Figure 14). However, this fuel-flexible unit was built with the capability of also cofiring differing amounts of pipeline natural gas or LNG, as well as fuel oil or biomass.

Figure 14 The Suralaya plant is the largest coal-fired station in Indonesia (photograph courtesy of Indonesia Power)

Natural gas is reported as a secondary or alternative fuel for numerous coal-fired plants in Asia, including Thailand and several regions of Indian and China. The situation is similar in parts of Europe, although coal-fired plants normally use only modest amounts of gas. Countries where this mode of operation prevails include The Netherlands, Romania, Germany, the Czech Republic, Austria, Slovakia, Poland, Italy, Moldova, Bulgaria, Turkey and Spain. A number of power plants within Russia and some of the former Soviet Union states such as Uzbekistan also operate in a similar manner.

A number of new projects that combine coal and gas firing are in development. In Dubai, the Hassyan power plant is under construction for the state-owned Dubai Electricity and Water Authority (DEWA). Once fully operational, it will have a capacity of 2.4 GW. Construction began in November 2016 and the plant is expected to be fully operational by 2023 (DEWA, 2017). DEWA plans to launch two additional projects, to eventually bring the total capacity to 3.6 GW.

A consortium comprising ACWA Power and Harbin Electric is currently building the (4 x 600 MW) ultrasupercritical coal-fired plant. The project is being supported by a 25-year power purchase agreement (PPA) with DEWA. This arrangement includes provision of a secure delivery of coal to the plant over the 25-year life of the PPA. The new plant will meet emission limits that are stricter than those specified in the EU Industrial Emissions Directive, and is intended to contribute to the Dubai Clean Energy Strategy 2050, which aims to generate 7% of the country's electricity from clean coal by 2030.

The Hassyan plant has been designed to operate on either 100% coal or gas, or combinations of both. In normal operation, natural gas will be used during start-up, shut down, and for flame stabilisation. It will be used in conjunction with coal throughout the operational range of the boiler (Grant, 2017). Gas will be used during start-up with coal, up to Minimum Stable Generation of just over 200 MW, and will also be used during coal milling plant flame ignition and stabilisation whilst starting or stopping coal burners. Gas will also be used to support boiler pressure and temperatures during unit shut down when milling plant is being purged. It will be supplied from the United Arab Emirates (UAE) gas network. The UAE is a gas producer, although it is a net importer of gas for power generation.

6.7 Summary

There are many coal-fired power plants that use limited amounts of natural gas alongside their coal feed. Often, coal remains the primary fuel with gas use limited to start-ups or plant warming operations. Because of the relatively small amounts used, many cannot be considered as cofiring in the true sense.

There are also a number of plants that cofire significant amounts of gas. Some are operating in the USA, where others are in the process of being converted or are the subject of ongoing feasibility studies. Elsewhere, there are a limited number of plants that currently cofire although potentially, there are others that could also operate in this way. However, a major factor is the availability of a reliable supply of gas at a suitable price. In some locations, although affordable for limited application, gas is too expensive for bulk use. Coal is often cheaper and more easily available.

Cofiring appears to offer advantages to at least some existing coal-fired plants. Plant economics can be improved through cost savings achievable by switching to the cheaper fuel. For example, in the USA, when changing from higher grade bituminous coal to subbituminous supplies from the Powder River Basin, gas burn can be increased to maintain plant capacity. Cofiring enhances fuel flexibility; if there is a problem with the supply of either source, the use of the most available fuel can be increased accordingly. The plant is no longer reliant on a single source of fuel.

Changing a coal-fired plant to cofiring will require changes to control systems and plant hardware. Some may be relatively minor although others could be more complex, depending on the particular boiler and associated plant systems. The combustion and heat transfer characteristics of coal and gas flames are different, and this can impact on the suitability of the plant's existing heat transfer surfaces. However, with a new plant designed for cofiring, some such technical issues may not apply. For example, rather than retrofitting different burners to an existing plant, appropriate measures could be incorporated at the design stage. This could include incorporation of suitable dual-fuel burners and associated gas supply and control infrastructure. Similarly, suitable heat transfer surfaces could be factored in.

There can be environmental advantages to be gained by cofiring - replacing some of the coal feed with gas will equate to lower plant emissions, an important factor in meeting environmental legislation. Lower emissions will also reduce the load on control systems; for instance, less FGD reagents will be consumed, SCR catalyst lifetime can be extended, and particulate collection systems will require less frequent cleaning. Adding gas in this manner may find greater public acceptance as a means for at least partially 'greening' coal-fired generation.

The biggest potential near-term market for cofiring appears to be the USA, where many utilities wish to extend the working lives of their plants whilst simultaneously reducing their environmental footprint. Cofiring can help reduce emissions, improve operational flexibility, and allow faster start-ups, bringing plants on line more quickly and cleanly. Elsewhere, the overriding factor is likely to be the price and availability of gas. Although this is currently inexpensive in the USA, it is much more costly or unavailable in many other locations. Furthermore, in some countries, exporting natural gas is a more lucrative option than using it in power plants – exports may take priority over domestic use. Thus, the viability of an individual project will depend on the particular set of circumstances prevailing.

Unlike solar-based systems, there is no requirement for additional land close to the power plant, although if not already supplied with gas, a new pipeline and associated infrastructure will be required. Depending on length and other factors such as licensing, this could be expensive.

As with coal-solar hybrids, various economic, operational and environmental factors need to be considered on a case-by-case basis. However, compared to solar, opportunities for cofiring are less restricted as there are more locations where both coal and natural gas are readily available.

7 Conclusions

Nearly all major economies rely on coal to some extent and many emerging ones do likewise. Despite competition from natural gas, nuclear power and renewable forms of energy, for many years, coal will continue to be used widely and in considerable quantities.

Coal use in general is coming under increasing scrutiny. In particular, power generation has often been singled out as a major source of conventional pollutant emissions and CO_2. In many countries, policies and legislation have been introduced to encourage the greater uptake of alternative systems that include gas-fired generation and renewables such as wind and solar power. Renewables are often promoted strongly through the introduction of emission reduction targets, obligatory renewables mandates, air quality directives, and emissions trading schemes. Financial incentives or various forms of subsidy are usually involved.

The biggest drawback with wind and solar power is their inherent intermittency and the high cost per unit of electricity generated. This variability impacts negatively on the operation of coal-fired power plants feeding into the same grid. Many of these were designed to work on steady-state base load, but are now forced to operate on a much more flexible or cyclical basis to accommodate input from renewables. Repeated start-stops, cycling or load following inevitably increases wear and tear on major plant components and decreases overall efficiency. However, this mode of operation has increasingly become the norm, and cost-effective ways to enhance their performance in terms of operating flexibility, environmental impact, and economics are being sought.

There are a number of ways in which these goals could be achieved. In the case of improving plant flexibility, this report examines two possible options: combining coal-fired generation with solar energy, and cofiring coal with natural gas. Although both techniques are already (or have been) used on a commercial basis, neither is currently used widely. Under the appropriate conditions, incorporation of either form of technology can offer a number of advantages to coal-fired power plants. But clearly, both have limitations. Solar-based projects will only make sense in locations that receive consistently high solar radiation. Similarly, cofiring with natural gas will only be possible where there is a reliable, affordable supply of gas.

In both cases, the criteria that a project must meet can be highly site-specific. Consequently, each must be considered on an individual basis. However, where the appropriate conditions exist, combining solar energy or natural gas with coal-fired power generation shows promise. Both hold the potential to improve operational flexibility, moderate plant costs, and reduce emissions. Both can provide benefits when retrofitted to existing coal-fired power plants, although their greatest potential appears to lie in new-build units, where each can be integrated fully at the design stage. In many countries, enhancing flexibility and efficiency, and reducing the associated environmental footprint will become increasingly important in maintaining an affordable and effective coal-fired power sector.

To date, solar hybridisation efforts have focused mainly on the retrofitting of existing coal-fired power plants. However, the greatest market potential lies in solar integration with newer, more efficient coal-fired power plants. By incorporating solar power at the design stage, it is predicted that much higher levels of solar energy could be utilised.

Despite the possible advantages that coal-solar hybridisation can offer, widespread uptake of the technology appears unlikely. This is due partly to the obvious limitation imposed by the need for adequate solar radiation that restricts the technology to certain regions. Also needed in the locality is a coal supply and coal-fired power plant suitable for retrofitting. Furthermore, opposition to fossil fuels in general, and coal in particular, may also be a limiting factor. A number of coal-solar hybrids have been proposed, with a few reaching at least semi-commercial operation. But various factors such as anti-coal policies and increasingly stringent environmental legislation has meant that their attraction, at least for some utilities, appears to have waned. However, there is still interest in a number of locations. There are niche applications where the conditions are right and there is a local need for electricity. For example, the project under development in Chile is located in an area of high solar radiation, with an existing coal-fired power plant suitable for retrofitting, and land available nearby for the solar collection system. Furthermore, the area is relatively remote and has a thriving mining sector that urgently needs more electricity. It appears likely that hybridisation in this manner can be an attractive technology in niche markets such as this, as well as for more 'mainstream' applications where the appropriate conditions prevail.

Hybridisation is unlikely to have a major impact on the overall amount of coal consumed globally, although it could do so on a more localised basis. If solar power was used to replace a significant amount of coal fed to a power plant (operating in 'coal saver' mode), the overall amount could actually decrease, although this would not be the case with plants operating in 'solar boost' configuration. However, hybridisation could provide other benefits such as lower coal costs, reduced plant O&M requirements, and a lower environmental impact.

The other technique addressed in this report is the cofiring of natural gas in power plants that currently rely on coal as their main fuel. There are many such plants that already use relatively small amounts of gas alongside their coal feed, although only a limited number can be considered as cofiring in the true sense. Often, coal remains the primary fuel with gas restricted to start-ups, plant warming operations, as back-up fuel, or possibly reburning for NOx control.

Currently, there are only a limited number of plants that cofire significant amounts of gas, although there are some in the USA that operate in this manner or are in the process of being converted. Others are under consideration or are the subject of ongoing feasibility studies. Elsewhere, there are some plants that cofire although potentially, there are others that could also operate in this way. However, a major factor is the availability of a reliable supply of gas at a suitable price. In some locations, although affordable for plant start-ups, gas is too expensive for bulk use. Coal is often cheaper and more easily available.

Cofiring offers possible benefits to at least some coal-fired plants. Cost savings can be made through the ability to switch between whichever fuel is cheapest at the time. There may also be the possibility of switching to a cheaper coal. Clearly, cofiring enhances fuel flexibility; if for some reason, the supply of coal or gas is restricted, the use of either fuel can be increased accordingly. The plant is no longer reliant on a single source. There are also possible environmental advantages as replacing some of the coal feed with gas will automatically equate to lower plant emissions, and this can be important in meeting environmental legislation. Lower emissions will also reduce the load on control systems. Adding gas in this manner may find greater public acceptance as a means for at least partially 'greening' coal-fired generation.

Alongside the need for a reliable supply of gas, there will also be technical issues and plant modifications that need addressing. Some of these may be relatively straightforward – for example, switching out existing burners for dual fuel variants. But others may be more problematic and result from issues such as the different heat transfer characteristics and requirements of coal and gas. Although these may create difficulties in some existing plants, for new ones, they could be accommodated at the design stage.

The biggest potential market for cofiring gas is currently the USA, where many existing utilities are keen to extend the working lives of their plants whilst simultaneously reducing their environmental footprint. Environmental legislation includes the MATS emission standards set under the toxics programme – these are federal air pollution limits that individual plants must meet by a set date. MATS compliance and state regulations have been the drivers for a number of cofiring projects, rather than the current push to limit greenhouse gas emissions (Gossard, 2015; Sznajderman, 2017). Cofiring appears to offer the possibility for at least some coal plants to meet these limits. Power plants are expensive assets that owners wish to keep running. Cofiring could provide a cost-effective means for reducing plant emissions and improving operational flexibility, and a number of ongoing projects intend to capitalise on the low price of gas in this way.

Replacing part of a power plant's coal feed with natural gas will inevitably reduce the overall amount of coal burned. However, adopting cofiring may allow a plant to meet prevailing emissions limits in a cost-effective manner, potentially, extending its working life. Thus, coal demand would continue, albeit at a reduced level. Cofiring could provide a viable alternative to complete closure, possibly the only other option.

Compared to solar hybridisation, opportunities for cofiring are much less restricted as there are many locations where both coal and natural gas are available; for example, the new DEWA project in Dubai. However, as with coal-solar hybrids, cofiring projects need to be evaluated on a case-by-case basis to ensure that the various economic, operational and environmental factors are fully considered.

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