Annex A. Technical options to enhance flexibility in thermal power plants

This annex provides details of the technical considerations and options for improving the flexibility of thermal power plants. The main goal of increasing power plant flexibility is to improve short-, medium- and long-term flexibility. As discussed in Chapter 2, the technical aspects of enhancing the operating performance of a power plant are highly relevant to short-term flexibility, which includes the ultra-short, very short and short term. The important operational characteristics that determine the level of power plant flexibility generally include minimum stable levels, ramp rates and start-up times. The technical considerations provided in this annex are based on these characteristics, while the technical options are considered on the basis of cost. Neither the technical considerations nor the options are specific to particular generation technologies. The options for each specific generation technology are provided in Annex B.

Technical considerations for improved flexibility in thermal generation

There is a wealth of options that can be implemented to enhance the flexibility of thermal generation plants. Their scope varies in investment intensity and selecting the best option is key to unlocking latent flexibility in existing generation assets. Retrofits are often seen as the main measure to enable new operational procedures with relatively low capital intensity, as they help extend the useful life of existing assets. However, even within retrofits, the cost and lead time can vary greatly depending on the particular step of the production process where they are implemented. The increase in plant performance and flexibility parameters may be enabled both, through minor retrofits to increase monitoring or through comprehensive equipment replacement. It should nonetheless be noted that training and personnel engagement are necessary to make these interventions workable in practice.

To make sense of this, initially it is logical to revisit the desired operational characteristics – reduced minimum stable levels, higher ramp rates and reduced start-up times – in respect of the challenges they pose for thermal generators.

Reduced minimum stable levels

Safely achieving lower minimum stable levels is valuable because it increases a power plant's stable operational range, decreases the running costs of fossil-fired spinning reserves and contributes to the reduction of variable renewable energy (VRE) curtailment. Six main aspects merit consideration when planning a reduction in minimum stable levels:

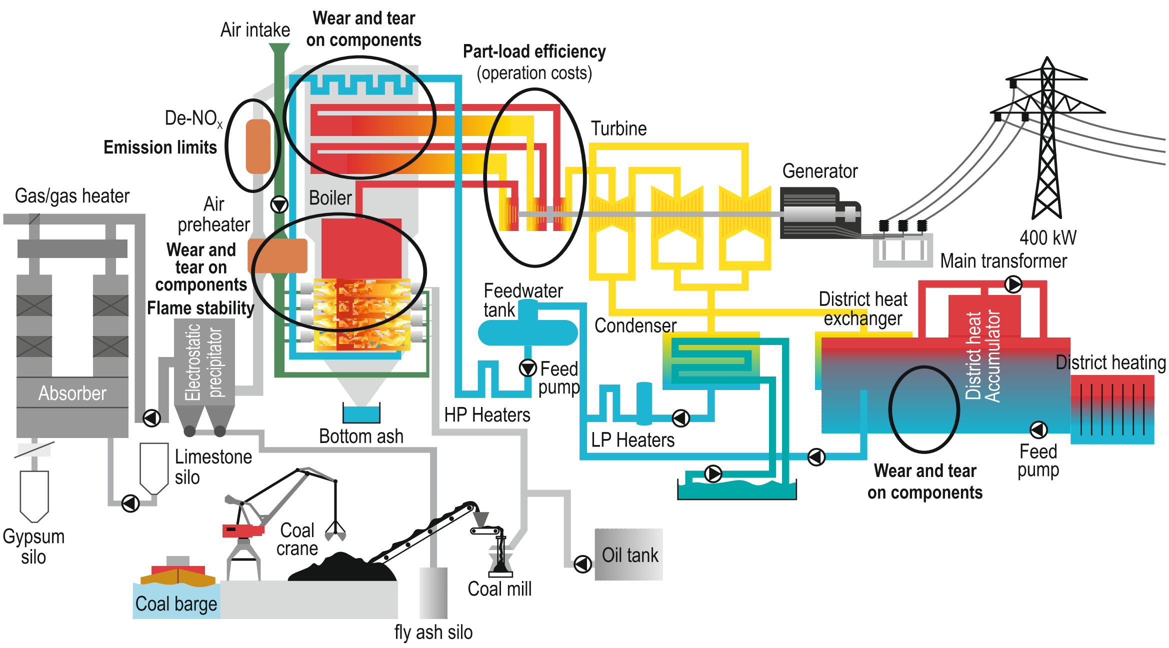
- **Flame stability:** In thermal plants, flame stability is of particular importance for the safety and reliability of electricity production. At low boiler load, flame stability can be addressed by optimising the burner system.
- **Emission limits:** Most plants nowadays are equipped with catalytic reduction systems to remove harmful nitrogen oxides (NO_x) resulting from fuel combustion, designed to perform optimally based on flue gas temperature. Operating plants at reduced loads also implies lower temperatures for the flue gases leaving the boiler and thus decreased performance in NO_x capture. In the case of gas turbines, NO_x emissions also become a limiting factor for low loads due to flame instability.

- **Wear and tear on components:** Power plants with a relatively high minimum stable level are likely to be required to start up and shut down more often, since they are unable to reduce their output down to the levels required by the system operator. Frequent plant start-ups and ramping increase the deterioration of generation plants due to thermal stresses, as the plant's components have to heat up and cool down more frequently.
- **Ability to control load:** In power plants with steam systems and co-generation, reducing the load will also result in a reduction in the amount of steam that is fed into the attached district heating network. Reduced steam output may actually affect the condensation process that feeds water back into the plant such that it becomes increasingly difficult to manage output.
- **Operation costs:** Depending on the type of load they are designed to serve, power plants will have an optimum generation level at which fuel efficiency is maximised. Running at low loads may result in the plant running at lower efficiency, leading to a noticeable increase in fuel costs.
- **Degree of manual operation:** As many power plants have not been designed and commissioned for low-load operation, the degree of automation at low load may be limited and require frequent manual operation by the plant's operators in parallel.

Other impacts from low load operation include: a reduction in air temperature, which may result in coal dust in the coal mill being incompletely dried during the pulverisation process; and reduced steam flow in low-pressure turbines, which may cause excessive exhaust temperature.

Figure A.1 is an illustration that demonstrates the links between the electricity generation process and the bottlenecks for reducing minimum stable levels at a coal-fired co-generation plant.

Figure A.1 • Barriers to minimum stable level reduction



Source: Blum (2017): "Practical experiences with making Danish coal plants flexible", presentation at the IEA Grid Integration of Variable Renewables (GIVAR) Programme Advisory Group meeting, 26 April 2017.

Key message • Barriers to low load operation include impacts on flue gas temperature, operation costs, flame stability, load control and automation.

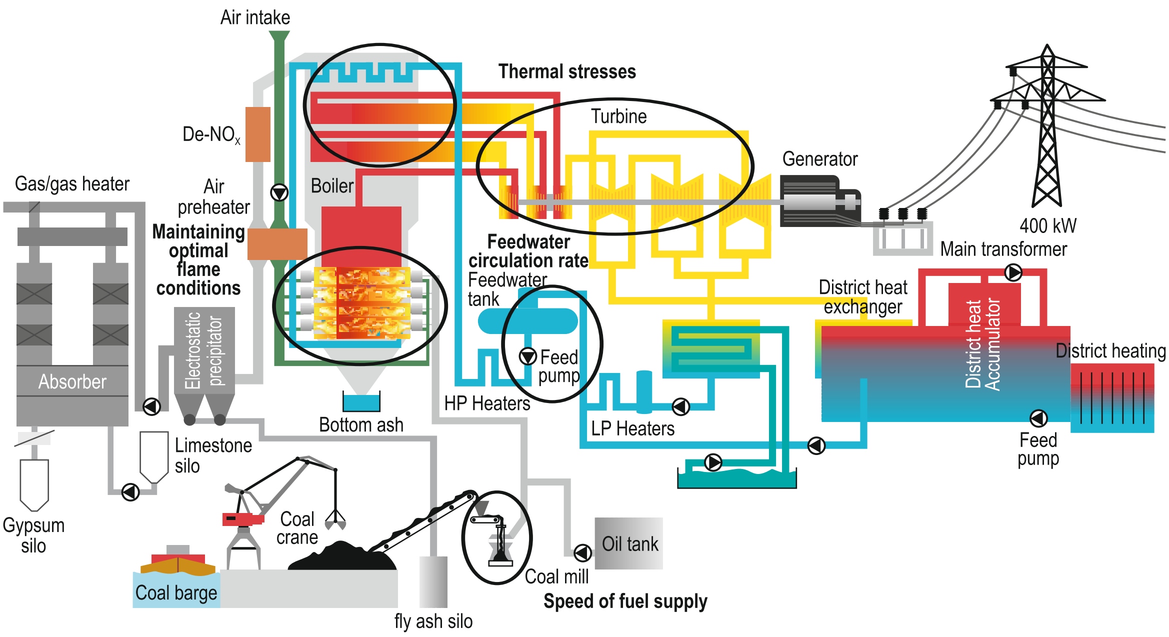
Higher ramp rates

Higher ramping requirements have become increasingly important for plants that originally served as baseload. Raising ramp rates in thermal power plants poses four main technical challenges:

- Maintaining optimal flame conditions: Fast ramping may have a detrimental effect on the optimal flame conditions within the plant's firing system due to rapid changes in fuel infeed. This may, in turn, reduce the remaining lifetime of the power plant.
- Speed of fuel supply: Any increase in plant firing will require adjustment to the rate of physical fuel delivery to the boiler. Constraints in the physical supply system of coal and gas will impact the plant's responsiveness to the need for higher electrical output.
- Feedwater circulation rate: For plants operating with steam systems, adjusting output requires regulation of the flow of feedwater into the boilers. Such flow adjustments must be closely co-ordinated with firing adjustments, as otherwise they may disturb other steps in the production process.
- Wear and tear on components: During fast ramping, different components of the power plant will heat up or cool down at varying speeds. This is likely to have negative impacts, particularly on thick-walled components, and may damage equipment. Changes to the status of air, fuel, water and steam should be co-ordinated to avoid deviations in the plant's operational parameters leading to increased wear and tear.

These are presented graphically in Figure A.2.

Figure A.2 • Barriers to higher ramp rates



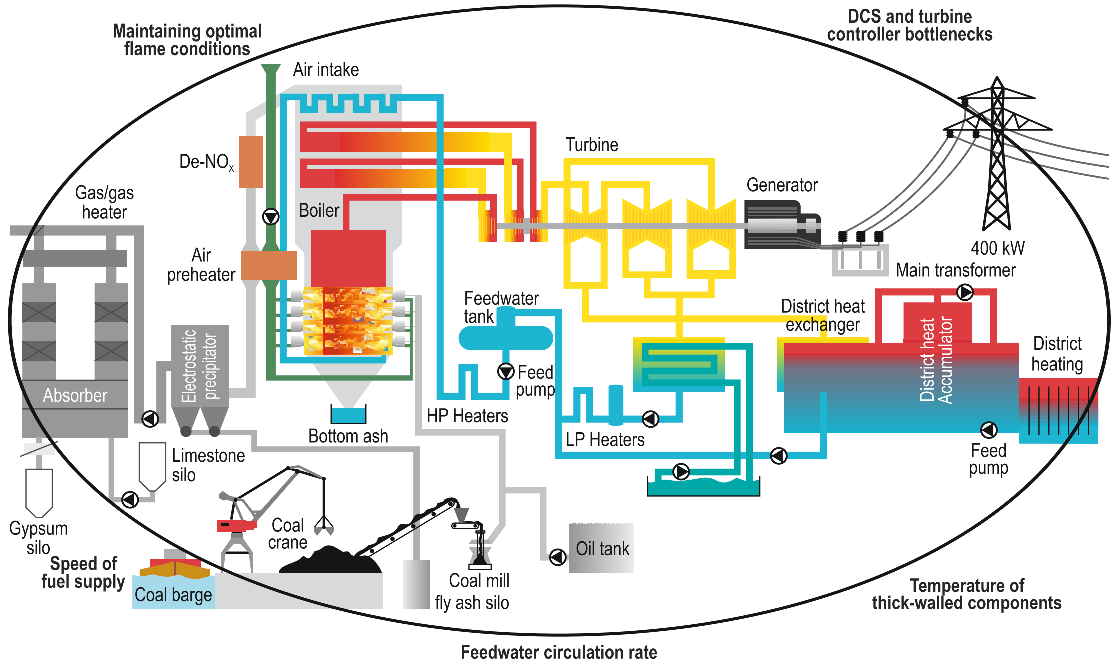
Source: Blum (2017): "Practical experiences with making Danish coal plants flexible", presentation at the IEA Grid Integration of Variable Renewables (GIVAR) Programme Advisory Group meeting, 26 April 2017.

Key message • **Barriers to increasing ramp rates include fuel supply constraints, ability to maintain optimal flame conditions, imbalance between firing and feed water, and wear and tear of equipment.**

Reduced start-up times

In order to reduce start-up times, thermal plants need to be brought to their stable temperature and pressure levels within a shorter period of time. Shorter start-up times present the same challenges as fast ramping, but with more critical effects on plant deterioration. One notable influence on start-up times is the presence of sequential start-up control procedures, where each step in the production process requires full operational stability of the previous step. Faster start-up times often require the reprogramming or installation of distributed control system (DCS) software for the turbine controller, as the start-up process is mostly dependent on software and far less operator-dependent than in previous decades. Utilising the temperature margins of thick-walled components to their limits by applying a stress controller is also another factor that can influence start-up times. Figure A.3 presents the principal barriers to reduced start-up times.

Figure A.3 • Barriers to reduced start-up times



Source: Blum (2017): "Practical experiences with making Danish coal plants flexible", presentation at the IEA Grid Integration of Variable Renewables (GIVAR) Programme Advisory Group meeting, 26 April 2017.

Key message • Barriers to faster start-up include keeping thick-walled components warm, maintaining sufficient water circulation of required quality, keeping flue gas paths warm and outdated controller software.

Technical options for enhanced flexibility in thermal generation

As discussed previously, the challenges posed by each of these flexibility requirements can be addressed through a number of minor and major retrofits. This section looks at a range of measures and presents them according to their cost level; however, it should be taken into account that, in practice, costs are highly plant specific.

- **Low cost** – for changes mainly involving engineering costs and minor investment in hardware.
- **Medium cost** – for changes involving engineering costs and medium-sized investment in hardware.
- **High cost** – for changes requiring major investment in hardware.

Low cost

- **Managing flame stability for reduced minimum stable levels:** Maintaining flame stability at low load levels is an issue in both coal- and gas-fired power plants. Such measures are highly plant specific as they require monitoring of flame stability in detail. Flame stability can be managed by optimising the burner system and controlling flow to each fuel burner.
- **Introducing a DCS for quicker start-up times, faster ramping and reduced minimum load:** The installation of a DCS can be an inexpensive fix for improving plant operation and the co-ordination of the different steps in the start-up process, ramping and load reduction. Modifications allowing the automation of processes along with real-time monitoring are instrumental in optimising operations.
- **Optimising instrumentation and control systems:** Instead of focusing on quicker start-up times, this option refers to the optimisation of the underlying control loops across the plant's various processes. These include fuel infeed, boiler drum level and air control. Potential restrictions presented by logistics (e.g. by preventing low load operation) should be removed.

Medium cost

- **Introducing steam system management for improved operating range and ramping:** Installing systems to shift steam back to the generating turbine may help increase generation above nameplate capacity over short periods of time, but at lower efficiency.
- **Redirecting steam in co-generation plants:** In systems with co-generation, it is possible to shift steam from power production to heat production by installing steam valves. This allows operators to decrease electrical output while maintaining constant heat output.
- **Retrofitting heat recovery steam generators (HRSGs):** Modifying combined-cycle gas turbines (CCGTs) by retrofitting HRSGs can be a useful method of decreasing thermal stresses, keeping the boiler warm during prolonged stops and increasing the system's de-heating capacity.

High cost

- **Retrofitting circulation systems in once-through boilers to reduce minimum stable levels:** Installation of a circulation pump system allows for lower loads in steam power plants based on once-through boilers. This can lead to a reduction in minimum stable levels from 34-40% to 20-25%, resulting from improved management of the water and steam system.
- **Retrofitting boiler systems for increased ramping capacities:** These measures contribute to the reduction of thermal stresses. This is possible by retrofitting water boilers such that the heat of flue gases is used to maintain boiler temperature even at reduced loads. Such systems can also ensure that the flue gas is kept at the right temperature for mitigating emissions increases when leaving the plant through the NO_x scrubber.
- **Local storage for improved flexibility in plants with co-generation:** Building local heat storage facilities can help decouple heat and power production. This applies to a number of technologies with district heating connections and can be done through either pressurised or atmospheric thermal storage.

Annex B. Detailed technical description of power plant technologies

This annex provides detailed technical descriptions that are specific to each power plant technology and which include limitations on power plant flexibility and technical options to enhance flexibility. The technologies covered are coal, gas, carbon capture and storage (CCS), nuclear, biomass, biogas, hydropower, wind, solar, and other renewable technologies, including marine and geothermal.

Coal-fired power generation

Coal is the dominant fuel in power generation today, still accounting for over 40% of generation globally. It is the main source of power production in both China and Germany, with shares of over 65% and 40% respectively. Its share in Denmark has decreased strongly, from around 45% in 2000 to below 30% by 2016.

Coal plants have typically been designed to supply baseload. The increasing share of renewables in the electricity system is challenging this paradigm and coal plants are now being forced to operate more flexibly than in the past. The flexibility of coal power plants can often be increased significantly through small operational changes and plant modifications. Deeper retrofits can further increase their flexibility. New-build coal plants have the opportunity to take the latest system requirements into account before construction at the design stage.

The following discussion focuses on pulverised coal, which remains the dominant technology for coal-fired power generation. Integrated gasification combined cycle (IGCC) plants have regained interest in recent years and are discussed in a separate subsection.

Pulverised coal-fired boiler

Pulverised coal (PC) combustion technology remains the most commonly used technology in coal-fired power plants today. In PC plants, powdered coal is injected into the boiler and burned to produce steam from water flowing through tubing within the body of the combustor, for subsequent expansion in a steam-turbine generator.

Subcritical units produce steam at pressures below the critical pressure of water (22.1 megapascals [MPa]). They typically achieve thermal efficiencies of up to 38% low heating value (LHV, net).

In supercritical units, the steam reaches a pressure above the critical point of water. Therefore no water-steam separation is required (except during start-up and shut-down). Supercritical plants typically achieve efficiencies of around 43%. These higher efficiencies lead to fuel savings compared to subcritical units. Capital costs are, however, higher for supercritical plants due to the greater stress resistance needed from plant components such as alloys and the welding techniques.

Ultra-supercritical (USC) units operate at even higher temperatures and pressures, and thermal efficiencies may reach 45%. Current state-of-the-art USC plants operate at up to 620°C, with steam pressures from 25 MPa to 29 MPa.

Supercritical and USC PC power plants offer better flexibility performance than subcritical power plants, which use boiler drums to separate water from the steam and are therefore limited in their load change rate. The high wall thickness of these components requires controlled heating and therefore load change rates are generally limited. Instead, supercritical or USC cycles use once-through boilers, which do not contain drums and can achieve rapid load changes, almost triple the performance of subcritical plants (IEAGHG, 2012).

Flexibility will also be a requirement for advanced ultra-supercritical (A-USC) plants, which aim for efficiencies exceeding 50% and will require materials capable of withholding steam conditions of 700-760°C and pressures of 30-35 MPa. The flexibility of A-USC plants is not known as yet. Development of the necessary materials and components, such as superalloys made of nickel, needs to keep up with the flexibility requirements being placed on power plants. Predicted start-up times for A-USC plants are slightly higher than for USC plants (IEACCC, 2014).

Table B.1 below shows the flexibility parameters of standard supercritical plants, as deployed, and current state-of-the-art supercritical coal-fired power plants. Ranges show minimum and maximum values for the plant parameters. A broad range of retrofit options (described in the following subsection) can yield substantial improvements to existing plants. The middle column highlights reported plant improvements through retrofits.

Table B.1 • PC performance parameters for supercritical plants

Parameters		Standard deployed technology	Retrofit with flexibility options	Commercially available new technology
Minimum stable load (%FL)		20.0-50.0	40->20	20.0
Ramp rate (%FL/min)		0.6-8.0	3->6	3.0-8.0
Start-up time (min)	Hot	150-180	60	75-150
	Warm	158-368	n/a	n/a
	Cold	300-600	300	180-360
Efficiency (%)	At MCL	37.1-40.1	n/a	n/a
	At 60%	n/a	n/a	n/a
	At 80%	n/a	n/a	n/a
	Net LHV	42.8-43.2	n/a	43
Lifetime	Years	40	40	40
Minimum up time	Minutes	480	n/a	n/a
Minimum down time	Minutes	240	n/a	n/a
Start-up cost (EUR/MW)	Hot	40-50	n/a	n/a
	Warm	70-100	n/a	n/a
	Cold	80-110	n/a	n/a
Running costs	EUR/MWh	2.7-3.4	n/a	n/a
Fixed O&M	EUR/MW/yr	40	40	42

Notes: FL = full load; MCL = minimum compliant load; min = minute; MW = megawatt; MWh = megawatt hour; n/a = not available or not applicable; O&M = operation and maintenance; yr = year.

Sources: IEA (2017a), *Energy Technology Perspectives 2017 – Catalysing Energy Technology Transformations;* NREL (2012), *Power Plant Cycling Costs;* Gonzalez-Salazar, Kirsten and Prchlik (2018), “Review of the operational flexibility and emissions of gas- and coal-fired power plants in a future with growing renewable”; Siemens (2017), “Flexibility of coal and gas fired power plants”, presentation; Agora Energiewende (2017), “Flexibility in thermal power plants – With a focus on existing coal-fired power plants”.

Limitations for power plant flexibility

Operating a plant flexibly can have harmful impacts on almost all elements of the plant. This concerns, in particular, the high-temperature and pressure components of the plants; the emission control systems and auxiliary systems are also vulnerable to potential negative impacts. Reduced life, reduced performance and increased cost are the consequences if adequate measures are not taken (e.g. retrofits, monitoring, changes in operational practices) (IEACCC, 2014).

Fatigue in the boiler and steam parts is a potential issue, as are maintaining boiler feedwater quality or ventilation at lower load levels. Power plants also face issues with emission limits, flame stability and load control at reduced load levels. Costs due to efficiency losses are likely to increase when plants are operated below their optimum load level. When increasing ramp rates, maintaining optimal flame conditions and the speed of fuel supply typically becomes an issue, as does increased wear and tear on power plant components. Challenges associated with improvements in start-up time are similar to those related to increasing ramp rates; however, plant deterioration might be exacerbated (see also Chapter 3 of the report).

Cost estimates of the harmful impacts of cycling and the different retrofit options described above are generally not publicly available. In terms of economic viability, each retrofit option has to be analysed on a per-plant basis. In general, the economic viability of a retrofit option has to be assessed in the context of the specific environment in which the plant is operating (e.g. market design, policy environment, electricity system) (Agora Energiewende, 2017).

Options to enhance flexibility

Options to increase flexibility exist in the boiler area, the water-steam and turbine systems, and in other plant areas such as the control and instrumentation systems (IEACCC, 2014). Boiler retrofits can improve ramp rates by up to 33%, turndown rates by between 33% and 50%, and start-up/shutdown rates by between 33% and 100%, depending on the measure taken. Coal mill retrofits lead to improvements of around 33% in the same parameters. Similar improvements are to be expected for turbine retrofits or emission control system retrofits (NREL, 2012).

The following lists provide details of the potential flexibility improvements with respect to their impact on plants characteristics (such as minimum load, start-up time or ramp rate), as an abbreviated form of the presentation in Agora Energiewende (2017).

Decreasing minimum load

- **Upgrade of control system in combination with plant engineering upgrades**
  - Control technology is critical for navigating between different load stages as well as for ensuring stable operation. Upgrades improve the precision and speed of these processes.
  - These measures are of particular importance when the scope for other modifications is limited, as for instance in some older plants.
- **Operation with reduced number of mills**
  - The plant is operated only at the highest burner stage during single mill operation.
- **Auxiliary firing with dried lignite ignition burner**
  - The fire in the boiler can be stabilised by combusting auxiliary fuels such as heavy oil or gas. This reduces the stable firing rate and hence minimum load.
- **Thermal energy storage (TES) for feedwater preheating**
  - Using TES, heat can be stored and released at later points in time, thereby allowing for changes in net power output without changing the firing rate.
- **Indirect firing**
  - Indirect firing allows the decoupling of the direct supply chain between coal mills and burners using a pulverised coal storage facility (dust bunker).

    - It can decrease minimum stable load down to 10% when used in combination with a staged vortex burner retrofit.

Decreasing start-up time

- **Repowering**
    - A gas turbine, which can ramp up significantly faster than a coal plant, is placed upstream of the water-steam circuit. The gas turbine can provide power immediately while the water-steam cycle is still heating up.
    - This also increases net power and overall efficiency of the plant.
- **Optimised control systems**
    - Predictive controller solutions allow for online optimisation of start-up.
- **Thin-walled components/special turbine design**
    - Thin-walled components allow for higher plant flexibility, often, however, at the expense of efficiency.
- **"New" turbine start**
    - This describes a procedure through which "cold" steam enters the steam turbine as quickly as possible after shutdown, reducing hot start-up time by 15 minutes.

Increasing ramp rate

- **Repowering**
    - The ramp rate is increased compared to the usual configuration, as an additional heat source (gas turbine) can preheat the feedwater.
- **Upgrading control systems and plant engineering**
    - Upgrading the control and communication systems not only reduces minimum load (see bullets above), but also can also improve ramp rates.
- **Reducing the wall thickness of key components**
    - Reducing wall thickness increases allowed temperature change rates, thereby increasing possible ramp rates.
- **Auxiliary firing with dried lignite ignition burner in booster operation**
    - An ignition burner can also be used during operation and thereby increase ramp rates.

IGCC

In coal-fuelled IGCC plants, coal is partially oxidised in air or oxygen (from an air separation unit [ASU]) in a gasifier at high pressure to produce a fuel gas. Electricity is produced in two phases via a combined cycle. First, the fuel gas is burnt in a combustion chamber and the hot pressurised gases are then expanded through a gas turbine. In a second step, steam is raised using the hot exhaust gases in a heat recovery steam generator before expanding it through a steam turbine. Unlike a PC plant, which uses only a steam turbine, IGCC plants hence use a combination of gas and steam turbines to produce electricity.

Technical performance parameters of IGCC plants are summarised in Table B.2, but some of these numbers depend strongly on the exact plant design. Minimum stable load is around 60-70%, but with multi-burner configurations this can be reduced to below 40%. Start-up behaviour depends on the interplay of the ASU and the gas turbine. Start-up times for membrane walls are significantly lower than refractory lining designs.

Table B.2 • Coal IGCC performance parameters

Parameters		Standard deployed technology
Minimum stable load (%FL)		60-70
Ramp rate (%FL/min)		3-5
Start-up time (min)	Hot	360-480 (refractory lining) 30 (membrane wall)
	Warm	
	Cold	4 800-5 400 (refractory lining) 120 (membrane wall)
Efficiency (%)	HHV	40
Lifetime	Years	40
Minimum down time	Minutes	420
Start-up cost	EUR/MW	18
Running costs	EUR/MWh	6
Fixed O&M	EUR/MW/yr	50

Note: HHV = high heating value.

Sources: IEA (2017a), *Energy Technology Perspectives 2017 – Catalysing Energy Technology Transformations;* IEACCC (2014), *Increasing the Flexibility of Coal-Fired Power Plants*; Kujanpaa and Pursiheimo (2017), "Techno-economic evaluation of flexible CCS concepts in a CHP system".

Limitations for power plant flexibility

Generally, IGCC plants are less flexible than combined-cycle or pulverised coal plants due to inertia related to process units (gasification, syngas cooling, etc.) and the ASU (IEAGHG, 2012). Furthermore, IGCC systems have so far not been designed for high-flexibility operation, but are instead optimised for baseload operation due to their high capital costs.

IGCC plants have higher capital costs than PC plants, which are (among other reasons) a result of higher redundancies to mitigate risk and the large number of subsystems. IGCC plants have therefore primarily been designed for baseload operation and cost data on flexibility improvements for IGCC plants are not readily available yet. The fact that the size of the gas turbine constrains the unit size has limited market deployment of IGCC plants to date. Cost reductions and greater operational experience are critical for developing the technology. IGCC may become more competitive when ultimately combined with CCS.

Options to enhance flexibility

Several options exist to increase the flexibility of IGCC plant designs. Designing IGCC plants for polygeneration provides the flexibility to use the fuel gas from coal gasification (syngas).[1] In a process that keeps syngas production stable, the syngas can be used for power generation and also to produce hydrogen, transport fuels, synthetic natural gas and chemicals.

Temporary storage of syngas and oversizing the ASU to allow liquid oxygen and nitrogen storage are potential means for increasing the load range. It is also possible to co-fire natural gas in the gas turbine. This permits the running of the gasifier and the power plant independently, thus increasing the plant's flexibility (IEAGHG, 2012).

[1] Polygeneration is an integrated process with three or more energy outputs.

Gas-fired power generation

Gas-fired power accounts for around 24% of global power generation. These plants are typically more flexible in their operation and cleaner than existing coal-fired power plants. However, at their respective minimum compliant load, gas plants typically become less flexible and produce more NO_x and carbon monoxide emissions than coal-fired power plants (Gonzalez-Salazar, Kirsten and Prchlik, 2018).

Open-cycle gas turbine (OCGT) and CCGT are the main types of gas power plant in operation today. The following section introduces these plant types and discusses their flexibility performance.

OCGT

Two types of OCGT power plant dominate the market today: F-class heavy-duty gas turbines (HDGTs) and aero-derivative gas turbines. They constitute the world's greatest installed fleets of large-capacity (>200 MW) and small-capacity (<50 MW) gas-fired power plants, respectively (Gonzalez-Salazar, Kirsten and Prchlik, 2018).

F-class HDGTs are currently the most widely installed technology. They have firing temperatures of around 1 300-1 400°C and are typically in the 170-300 MW range. Characteristics of current and future plants are given in Table B.3 below. Note that the start-up time of OCGTs is not dependent on downtime.

Table B.3 • HDGT performance parameters

Parameters		Standard deployed technology	Retrofit with flexibility options	Commercially available new technology
Minimum stable load (%FL)		35.0-40.0	20	20-50
Ramp rate (%FL/min)		7.5-16.3	16+	19.3
Start-up time (min)		6.5-22.6	n/a	11.7
Efficiency (%)	At MCL	23.4-29.8	n/a	n/a
	At 60%	n/a	n/a	n/a
	At 80%	n/a	n/a	n/a
	Net LHV	38.1-40.5	n/a	42
Lifetime	Years	35	35	35
Minimum uptime	Minutes	60	n/a	n/a
Minimum downtime	Minutes	0-360	n/a	n/a
Start-up cost (EUR/MW)	Hot	25-50	n/a	n/a
	Warm	40-120	n/a	n/a
	Cold	40-120	n/a	n/a
Running costs	EUR/MWh	0.5-0.6	n/a	n/a
Fixed O&M	EUR/MW/yr	20	20	20

Sources: IEA (2017a), *Energy Technology Perspectives 2017 – Catalysing Energy Technology Transformations;* NREL (2012), *Power Plant Cycling Costs*; Gonzalez-Salazar, Kirsten and Prchlik (2018), "Review of the operational flexibility and emissions of gas- and coal-fired power plants in a future with growing renewables".

Small OCGTs have been used for peaking applications for many years because they can be started quickly and ramped up and down rapidly (Table B.4). Aero-derivative gas turbines are the most widely installed gas-fired technology at small capacity (<50 MW). They consist of an aircraft-derived gas generator and a free power turbine, and are lighter and more compact than HDGTs.

Table B.4 • Aero-derivative performance parameters

Parameters		Standard deployed technology	Commercially available new technology
Minimum stable load (%FL)		18.0-75.0	20.0
Ramp rate (%FL/min)		82-132	194
Start-up time (min)		0.6-8.3	n/a
Efficiency (%)	At MCL	31.7-40.8	n/a
	Net LHV	33.5-43.1	n/a
Lifetime	Years	35	35
Minimum uptime	Minutes	60	n/a
Minimum downtime	Minutes	0-360	n/a
Start-up cost	EUR/MW	10-70	n/a
Running costs	EUR/MWh	0.6-0.7	n/a
Fixed O&M	EUR/MW/yr	20	20

Sources IEA (2017a), *Energy Technology Perspectives 2017 – Catalysing Energy Technology Transformations;* NREL (2012), *Power Plant Cycling Costs*; Gonzalez-Salazar, Kirsten and Prchlik (2018), "Review of the operational flexibility and emissions of gas- and coal-fired power plants in a future with growing renewables".

Limitations for power plant flexibility

Combustion processes and hardware stress are key elements that limit ramping capability in OCGTs. Both the control system and hardware need to be nimble to support ramping, as the combustion system will be operating in a transient condition. Sustaining the combustion process can be a challenge and an adequate fuel-air ratio has to be ensured.

Carbon dioxide (CO_2) compliance can be a challenge when reducing minimum load: when load is reduced, the combustion temperature is lowered as well. While NO_x emissions decline at low loads, CO_2 emissions increase. Techniques that aim to improve the turndown capability typically try to increase combustion temperatures, often, however, at the expense of efficiency. Such options, for example bypassing compressor discharge air around the combustion system, are increasingly available on new units and as retrofits.

Options to enhance power plant flexibility

Improvements via retrofitting can result in ramp rate increases of 100% and more, reductions in start-up time of 60% and 10% more rapid turndown (NREL, 2012). NREL (2013) discusses several solutions for increasing the flexibility of simple-cycle gas turbines.

Start-up times can be improved by reducing or eliminating the purge cycle. The purge refers to the procedure of monitoring the gas turbine prior to introducing the fuel so that all combustibles are removed from the exhaust. Furthermore, so-called ignition "light-off" procedures allow higher-speed ignition, which saves time by avoiding a coast-down from purge speed to light-off speed. With a combination of improved analytical techniques, advanced control systems, case and rotor temperature management methods and enhanced materials technologies to improve tip clearance management, simple gas turbine start-up times can be reduced by more than 50-60%.

CCGT

Conventional, modern large-scale CCGT power plants are usually based on a single gas turbine with a single steam turbine (1+1 specification), or two gas turbines with a common steam turbine (2+1 specification). CCGT plants can operate at high efficiencies at full load, exceeding even 60%, but efficiencies drop rapidly at lower loads.

While gas turbines (e.g. the F-frame described in the previous section) are mostly standardised, HRSGs and steam turbines in CCGTs are very heterogeneous. They are highly customised for each application, which makes comparing plant performance parameters difficult. Parameters of current and future plants are listed in Table B.5 below and are based on the specifications in Gonzalez-Salazar, Kirsten and Prchlik (2018). Their data are based on a typical configuration for a F-class HDGT combined-cycle plant, namely a three-pressure HRSG and a three-casing reheat steam turbine.

Start-up times in CCGTs vary as a function of the thermal state of the bottoming-cycle equipment (i.e. hot, warm, cold). CCGT start-up times can be significantly longer in the absence of a well-integrated digital control system to assist with the start-up (NREL, 2013).

Older combined-cycle units were designed and operated for baseload operation. These plants have higher cycling costs compared to units specifically designed for cycling, explaining the variability of costs (NREL, 2012).

Table B.5 • CCGT performance parameters

Parameters		Standard deployed technology	Retrofit with flexibility options	Commercially available new technology
Minimum stable load (%FL)		32.6-53.8	20, 35, 40	30.0-40.0
Ramp rate (%FL/min)		2-4	3 -> 10+	4-8
Start-up time (min)	Hot	8.5-39.3	30	20-30
	Warm	16.0-119.6	n/a	75.2
	Cold	16.0-195.2	n/a	122.8
Efficiency (%)	At MCL	49.1-55.4	n/a	n/a
	Net LHV	56.4-58.2	n/a	59-60
Life-time	Years	35	n/a	35
Minimum uptime	Minutes	240	n/a	n/a
Minimum downtime	Minutes	30-360	n/a	n/a
Start-up cost (EUR/MW)	Hot	25-50	n/a	n/a
	Warm	30-100	n/a	n/a
	Cold	30-100	n/a	n/a
Running costs	EUR/MWh	0.9-0.94	n/a	n/a
Fixed O&M	EUR/MW/yr	25	n/a	25

Sources: IEA (2017a), *Energy Technology Perspectives 2017 – Catalysing Energy Technology Transformations;* NREL (2012), *Power Plant Cycling Costs*; Gonzalez-Salazar, Kirsten and Prchlik (2018), “Review of the operational flexibility and emissions of gas- and coal-fired power plants in a future with growing renewables”.

Limitations for power plant flexibility

Many CCGT plants were not designed for cycling, but rather for baseload operation. Cycling these plants leads to reduced component lifetime, increased outage rates and ultimately higher operating costs. Furthermore, these plants typically experience a high efficiency penalty at part-load operation.

Options to enhance power plant flexibility

For combined-cycle power plants, different avenues are available for improving operational flexibility. NREL (2013) identifies options for improvement through changes in the design of the HRSG, the steam turbine and the balance of plant (BOP). Newer combined-cycle plants improve flexibility by breaking the link between the gas turbine and the steam turbine cycle.

The IEA (2014a) identified the following measures for increasing flexibility, which can in some cases also be retrofitted to plants.

- **Variable-pitch guide vanes and inlet preheaters improve combustion for part-load and minimum-load performance.** Variable-pitch guide vanes allow for a better control of the airflow though the turbine, minimise the reduction in combustion kinetics at part load, and increase reactivity, thereby leading to lower specific fuel consumption and emissions. Air inlet preheaters placed in front of the compressor can improve part-load efficiency and minimum load.
- **Improved HRSG design increases ramping capability and reduces start-up times.** HRSGs using thick-walled components limit the ramping capabilities of CCGTs, and prolong start-up and shutdown times. Modification to the HRSG or bypassing the steam cycle could lead to steeper ramp rates and improved start-up times.
- **Advanced new materials and sensing reduce cycling impacts.** Advanced less heat-sensitive materials can reduce the impacts of cycling operation.

CCS

CCS enables the decarbonisation of fossil fuel-based power plants or creates negative net emissions when combined with biomass power plants. There are currently two large-scale, integrated power plant CCS projects in operation around the world.[2] These operate as baseload capacity and, as a result, experience with the flexible operation of large-scale systems is limited. Most information on this topic stems from experiments with pilot plants, global research and development programmes, and literature. The impact of the three main carbon capture routes – post-, pre- and oxyfuel combustion – on the operational flexibility of fossil fuel-based power cycles is discussed below. The flexibility of oxy-combustion power generation cycles (e.g. Allam cycle) and solid looping capture technologies (e.g. calcium looping) is not discussed in this chapter, due to limited information being available on this topic.

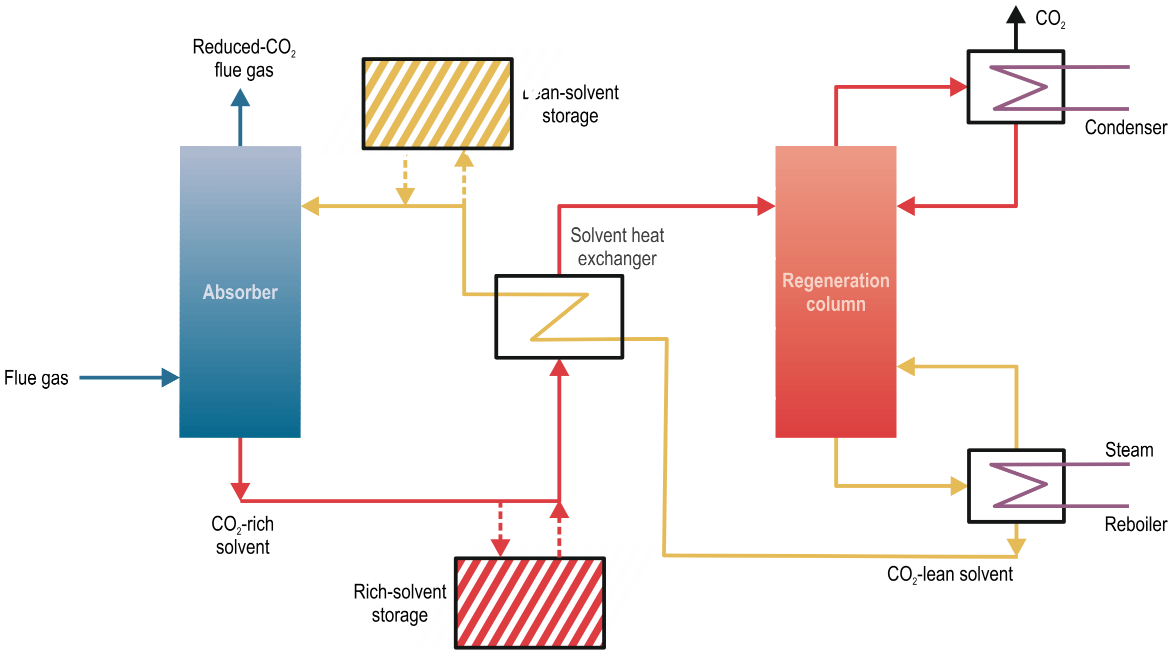
Post-combustion capture

Post-combustion capture (PCC) refers to the process in which CO_2 is separated from power plant flue gas after the fossil fuel or biomass has been burned. Due to the low concentration of CO_2 in

[2] Both CCS projects are related to post-combustion capture technology applied to coal-fired power plants: the Boundary Dam project in Saskatchewan, Canada, and the Petra Nova Carbon Capture project in Texas, United States, with annual capture capacities of 1.0 and 1.4 million tonnes of CO_2, respectively.

the flue gas (typically 3-4 vol-% for natural gas and 12-16% for coal), capture is normally performed by chemical absorption using a sorbent, typically an amine-based solvent in current demonstration projects.[3] In such systems, flue gas is sent through an absorption column, counter-current to the direction of the liquid solvent flow (Figure B.1). The solvent selectively reacts with and absorbs the CO_2 in the flue gas. The CO_2-rich solvent is subsequently pumped into a regenerator column where it is heated with steam to liberate gaseous CO_2. The steam is either taken from the power plant steam cycle and sent to the reboiler, or produced in a separate, additional energy plant. The lean solution is recirculated back to the absorber. Both the cold CO_2-rich solution and hot CO_2-lean solution pass through a heat exchanger to reduce reboiler heat production. The separated CO_2 is then purified/dried and compressed for subsequent transport and storage.

Figure B.1 • PCC system based on chemical absorption



Source: Based on IEAGHG (2012), *Operating Flexibility of Power Plants with CCS*, 2012/06, ieaghg.org/docs/General_Docs/Reports/2012-06%20Reduced.pdf.

Key message • Post-combustion capture is an add-on technology, requiring only minor modifications to the power plant.

Limitations for power plant flexibility

Solvent
heat
exchanger

PCC units do not appear to affect the minimum stable operating load of gas- and coal-based power plants, as the plants' minimum load levels are typically similar to or lower than those of PCC units. In fact, the additional steam and power requirements of the PCC unit could reduce the minimum net load of integrated power-PCC. The minimum stable operating load of the PCC unit is determined by the absorber. Modern absorption columns have a minimum technical part-load operation of around 20-30% (E.ON, 2011; IEAGHG, 2012, 2017). Lower part-load operation would result in too low a vapour/liquid ratio in the absorber, leading to operational problems called

[3] Advanced PCC technologies based on membrane separation, calcium looping or adsorption are expected to become commercially available in the future. However, their flexibility is not discussed here.

dumping or weeping (Perry and Green, 2008). Most CO_2 compressor systems with electric drivers are capable of turndown to approximately 70-75% of full flow at constant discharge pressure. Lower load levels can be achieved by recirculating part of the compressed CO_2; hence, there are probably no technical constraints on the minimum load level of compressors, but recirculation reduces energy performance (IEAGHG, 2012). Another option for controlling compressor performance is the use of variable speed drives, which enable the adjustment of the rotating speed of the compressor to change the mass flow capacity (Sanchez Fernandez et al., 2016).

The addition of a PCC system will probably not reduce the ramp rate of a power plant and could actually increase the ramp rate for net power output if the PCC and power equipment are operated independently (e.g. ramp the capture system down while ramping the power system up). Furthermore, PCC systems can enhance the frequency response capabilities of the power plant by modulating the steam flow extracted from the steam cycle for the CO_2 capture process, resulting in a higher or lower electricity output (Tait et al., 2016; Wellner, Marx-Schubach and Schmitz, 2016). In general, PCC units can quickly adjust to a change in flue gas flow, although their exact ramp rate is unknown. Cohen, Rochelle and Webber (2012) assume an absorber/stripper ramp limit of 5% per minute, which is based on the premise that a flexible capture plant is able to respond more quickly than the power plant (4% per minute for PC plants). However, they add that realistic operational difficulties may prohibit fast ramping. As regards CO_2 compressors, these units do not limit power plant capabilities to change load quickly. Ramp rates depend on the type of compressor, but are typically very short (IEAGHG, 2012). No quantitative data were found for compressor ramp rates. In general, PCC units would reduce the flexibility of gas units more than that of coal units, as gas-based power plants are typically more flexible than coal-based power plants.

A PCC system could impose additional constraints on the overall start-up time of the integrated power system with PCC. The main bottlenecks are related to the reboiler and regeneration column, as heating up these components requires two hours (hot start-up) to four hours (warm start-up) from the moment that steam is available from the steam cycle. However, in decoupled operation of the power and CCS islands, the start-up time of the power plant would not be affected (IEAGHG, 2012; Kvamsdal, Jakobsen and Hoff, 2009).

Flexible operation is likely to increase start-up and fixed O&M costs, due to higher costs for forced outages, maintenance and capital expenditure, and material and fuel consumption. However, these costs have not been quantified in literature. Additional start-up costs are not expected to be very high compared to those of a power plant without CO_2 capture. Cohen, Rochelle and Webber (2012) investigated the sensitivity of volatile electricity prices to a range of capture unit start-up costs, and found that capture unit start-up costs hardly affect electricity prices if they are set equal to the start-up costs of a coal-fired power plant.

The overall energy efficiency of power plants with a PCC unit falls when operated at part load, especially gas turbines without so-called inlet guide vanes. As regards the power plant, the efficiency penalty related to steam extraction from the steam cycle may become progressively larger as the load level declines, depending on the arrangements for steam extraction and the normal pressure at the steam extraction point. The penalty results either from increased throttling losses in the steam turbine or reduced pressure in the boiler, caused by the need to maintain sufficient steam pressure to the regenerator column. The energy penalty is likely to be more evident for retrofitted plants, which were not designed for low-pressure steam extraction and may therefore face heavy throttling losses at part-load operation. An exception exists for power plants with let-down back pressure turbines, which demonstrate performance similar to newly built power plants with a PCC unit (IEAGHG, 2012). At lower load, the flue gas changes its mass flow and composition (lower CO_2 vol-%, higher O_2 vol-%), which has two impacts on the downstream PCC unit: (i) better CO_2 mass transfer in the absorption column due to the overdesign of the absorber and stripper for that load, thereby reducing the regeneration level; and (ii) a lower temperature difference in the amine solution heat exchanger owing to the lower solution flow rates at part load (Roeder, Hasenbein and Kather, 2013). The decreasing temperature of steam extracted from the power cycle is another contributing factor to the increasing efficiency penalty at lower part loads. This leads to a reduction in the pressure in the regeneration column, resulting in an increase in compression power and in the amount of steam required for the desorption process.

As mentioned before, most CO_2 compressor systems with electric drivers are able to turn down to 70-75% part-load operation without incurring significant efficiency losses. Higher turndown rates can be achieved by recirculating part of the compressed CO_2, but doing so imposes a significant energy penalty. It should be noted that most power plant applications require multiple compressor trains because of the maximum size of compressors available in the market. In this case, higher efficiencies can be maintained at lower loads by turning off one or more of the compressor trains, so that the remaining compressors have an individual part-load operation of at least 70-75% (Liebenthal and Kather, 2011; IEAGHG, 2012).

Brouwer et al. (2015) collected data on state-of-the-art part-load efficiencies from technical reports and manufacturer specifications. They plotted second-order part-load efficiency curves for PC-CCS and natural gas combined-cycle (NGCC)-CCS plants based on the reported data points. These plotted curves express part-load efficiency as a percentage of full-load efficiency (see Table B.6).

Options to enhance flexibility

The start-up time and ramp rate of power plants with PCC units can be increased by means of several options, which can also be used to produce additional electricity during grid peak demand. The flexibility options are:

- **Varying solvent regeneration.** A given solvent can absorb a range of CO_2 quantities per volume passed through it depending on PCC unit operation, with the selected absorption range (termed "CO_2 loading") typically being chosen for optimal cost performance. However, by allowing CO_2 to accumulate in the solvent (higher CO_2 loading) during peak hours and regenerating the solvent during off-peak periods, the solvent itself can be used as a means to provide flexibility, unlike the option in which volumes of solvent are stored in tanks after absorbing the nominal amount of CO_2. This does, however, result in higher specific energy consumption per tonne of CO_2 captured, as varying solvent regeneration requires oversized equipment (e.g. reboiler, compressor and possibly downstream transport and storage infrastructure) to accommodate the CO_2 release peaks. Varying solvent regeneration can also be used for arbitrage purposes.
- **Storage of solvent**. Solvent storage can be used to increase the start-up time and ramp rate of the power plant (see Figure B.1). Moreover, solvent storage enables decoupling of the absorption column from the regeneration and compression section, thus temporarily bringing energy consumption close to zero without temporarily increasing CO_2 emissions. While the regeneration and compression blocks are shut down, the CO_2 absorption process continues. Regeneration of CO_2-rich solvent and CO_2 compression can then occur during periods of low power demand or otherwise when electricity prices are lower. Similar to the option of varying solvent regeneration, the solvent storage option also requires oversized equipment to accommodate the CO_2 release peaks.
- **Ramping down or turning off the PCC unit independently of the power block.** Partial- or zero-load capture can be achieved by either reducing the steam and rich solvent flows to the regenerator column, or by bypassing the capture unit completely. The former option enables

better process control of the capture unit. Reducing energy use for solvent regeneration and CO_2 compression allows more electricity to be produced, although CO_2 is vented to the atmosphere. However, the low-pressure turbine section, condenser and generator require appropriate design to accommodate the increased gas or steam flow. In a retrofit application, these plants were originally designed to operate without CO_2 capture and can therefore manage these flows. New plants with PCC units will require a design that has a capacity margin for the low-pressure steam section.

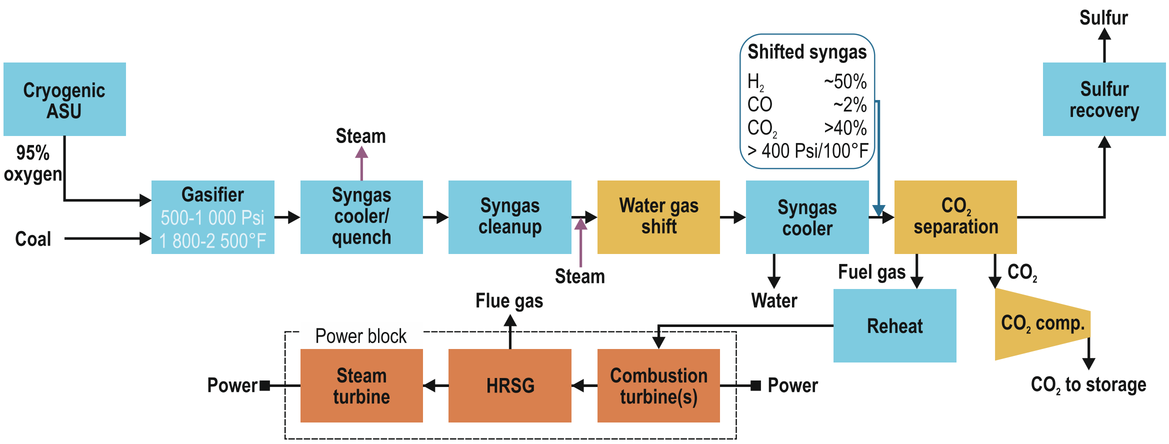
- **Continuous solvent circulation.** Maintaining solvent circulation after power plant shutdown allows the solvent inventory to cool more rapidly than when solvent circulation is stopped. Consequently, during start-up, a full inventory of solvent is available at ambient temperature, which greatly increases the absorption capacity to capture emissions when steam from the power cycle is not fully available (Ceccarelli et al., 2014).

As the first three of these options require additional capital investment, cost-benefit analysis before the investment decision should ensure that flexible PCC operation provides sufficient financial contribution to make it worthwhile over the lifetime of the equipment.

Pre-combustion capture

In the power sector, pre-combustion capture technology is typically considered for application in IGCC plants using coal (Figure B.2) or in gas-based power plants (e.g. CCGT). The latter option involves using a steam methane reformer (SMR) with CO_2 capture to produce hydrogen (not shown here). The addition of the capture unit only affects the IGCC or CCGT plant marginally. For both IGCC and CCGT plants, a water-gas shift (WGS) reactor is installed after the gasification/reforming section to convert carbon monoxide (CO) present in the syngas into CO_2 and hydrogen by adding steam. The CO_2 can be separated from the high-pressure gas mixture by physical or chemical absorption. The remaining gas flow, consisting mainly of hydrogen, is mixed with nitrogen/steam and fed to an adapted gas turbine. The separated CO_2 is then purified/dried and compressed for subsequent transport and storage.

Figure B.2 • Coal-based IGCC plant with pre-combustion capture system



Notes: Comp. = compressor; °F = degree Fahrenheit; H_2 = hydrogen; Psi = pounds per square inch.

Source: Provided by the U.S. Department of Energy's National Energy Technology Laboratory (2013), *Carbon Capture – Technology Program Plan*.

Key message • CO_2 capture from IGCC plants involves the addition of only a few process steps: water-gas shift reaction, CO_2 separation and CO_2 compression.

Limitations for power plant flexibility

As with their application in PCC systems, modern physical or chemical absorption CO_2 capture systems have a minimum stable operating load of 25-35% and do not, therefore, appear to affect the minimum stable operating load of IGCC or CCGT plants. CO_2 compressor systems do not pose a technical constraint on the overall plant's minimum operating load, provided they comprise multiple trains or are able to recirculate part of the compressed CO_2.

IGCC plants without CO_2 capture are unable to ramp up and down rapidly, due to the inertia of the gasifier, oxygen plant (ASU) and syngas treatment unit. The limited number of existing IGCC plants used for power purposes has resulted in limited interest in improving their plant flexibility capabilities to date. The addition of the gas clean-up section and CO_2 capture system to the IGCC plant is not expected to impose additional constraints on its ramp rate or overall start-up time, as the ASU requires more time to change load than the reboiler and regeneration column of the capture system. No information was found on whether flexible operation of the capture unit would increase the operational cost of the IGCC-CCS plant, or not.

IGCC plants with CO_2 capture have lower part-load efficiency due to the lower efficiency of CO_2 compressors at part load, as already discussed in the PCC section above. This reduction depends mainly on gas turbine performance and the number of gas turbine trains, which can differ considerably by gas turbine type. The IEAGHG (2012) indicated that an IGCC-CCS system operating at full load has an efficiency rate of 31.4%, compared with 30.0% at 56% load, an efficiency penalty of 1.4 percentage points.

Options to enhance flexibility

As the flexibility of an IGCC-CCS system is mainly constrained by the gasifier, ASU and syngas cleaning units, most options to enhance flexibility apply to the IGCC plant itself. These have already been discussed in the previous sections. Nevertheless, several additional options specifically relate to IGCC-CCS systems:

- **Hydrogen storage/co-production.** IGCC-CCS plants produce hydrogen, which can be stored temporarily and used to improve the plant's maximum power output and ramping capability. Hydrogen is also an energy carrier with multiple end-use possibilities: for electricity production, or as a chemical building block, a transport fuel or replacement for natural gas, and so on. By designing an IGCC plant to co-produce electricity and hydrogen as a product for sale, greater operating flexibility can be achieved. This concept allows the ASU, gasifier, syngas treatment unit and CO_2 capture equipment to operate as baseload, while the gas turbine responds flexibly in response to variations in electricity demand. The revenues from the sale of additional electricity and hydrogen must outweigh the related extra capital costs to justify the implementation of hydrogen storage and/or polygeneration (IEAGHG, 2012).
- **Turning off (part of) the capture unit independently of the IGCC.** CO_2 separation from the syngas can be temporarily halted to save energy for the CO_2 capture and compression process, resulting in a net power production increase of 10-15% (IEAGHG, 2012). Switching off the capture unit would, however, change the composition of the process gas going into the turbine, which has not been designed for such operation (IEAGHG, 2012). Another option is to continue the CO_2 separation process, but to temporarily store the solvent and/or gaseous CO_2 to save energy required for solvent regeneration and/or compression, which can be used to generate electricity during peak hours. The stored CO_2-rich solvent and/or stored gaseous CO_2 can be respectively regenerated and compressed when power prices are lower. In addition, part of the uncaptured CO_2 in the process gas may act as a diluent in the gas turbine, saving electricity used for nitrogen compression as less compressed nitrogen is needed for the gas turbine. However, this would also change the composition of the

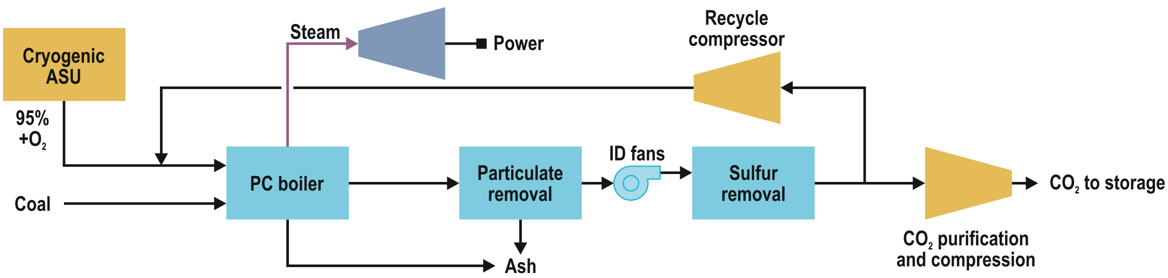
expanding gas in the turbine, which could potentially affect the turbine blade cooling paths and lead to combustion issues, such as flame stability. This option may require part of the CO_2 to be vented to the atmosphere.

- **Storage of solvent.** As with PCC systems, temporary solvent storage can reduce the energy required for solvent regeneration. While the regeneration and compression blocks are shut down, the CO_2 absorption process continues. Regeneration of CO_2-rich solvent and CO_2 compression can then occur during periods of low power demand or otherwise when electricity prices are lower. Similar to the hydrogen storage option, solvent storage requires oversized equipment to accommodate the CO_2 release peaks.

Oxyfuel combustion capture

Oxyfuel combustion is a process in which the fossil fuel or biomass is burned with (nearly) pure oxygen instead of air (Figure B.3). This way, virtually all the flue gas comprises CO_2 and water. Part of this flue gas is recirculated to the combustion chamber to dilute the oxygen and control the combustion temperature. The remainder of the flue gas is dehydrated and purified to obtain a high-purity CO_2 stream. For large-scale applications, such as large oxyfuel power plants, oxygen is produced in an ASU under very low temperatures by capitalising on the different condensation points between oxygen and other gaseous components in air. For small power plants (10-40 megawatts electric), pressure swing adsorption (PSA) or membrane technologies are used as these technologies offer better economic performance at small scale.[4] The separated CO_2 is then purified/dried and compressed for subsequent transport and storage.

Figure B.3 • Coal-based power plant with oxyfuel combustion capture system



Note: ID = induced draught.

Source: Provided by the U.S. Department of Energy's National Energy Technology Laboratory (2013), *Carbon Capture – Technology Program Plan*.

Key message • Oxyfuel CO_2 capture involves several additional process steps: oxygen production, CO_2-rich flue gas recycling, and the purification and compression of CO_2.

Limitations for power plant flexibility

Oxyfuel combustion is unlikely to reduce the minimum operating load of coal-based power plants. Although both the air compressors in the ASU and the CO_2 compressors have a high minimum operating load of 70-75%, lower compressor loads can be achieved by recirculating part of the compressed air/CO_2 or installing multiple compressor trains. As described in the PCC section, multiple CO_2 compressors are likely to be installed in any case. Furthermore, oxygen storage can be used to address the problem of the minimum operational load of the ASU, which

[4] The flexibility of PSA and membrane technologies are not considered in this section as oxyfuel combustion is mainly envisaged for large-scale power plants. In general, PSA systems have a much higher dynamic than ASU plants, and are thus less likely to limit the flexibility capabilities of coal- and gas-based power plants.

is reported to be 35-50% without oxygen storage. During low grid demand, the minimum load of the ASU can be maintained by storing surplus oxygen in tanks, or by switching off the ASU while using oxygen from the storage tanks. Industry already widely practises oxygen storage at ASU plants to take advantage of low electricity prices during off-peak periods.

For gas-based power plants, oxyfuel combustion may increase the minimum stable load of the gas turbine from 30-50% to around 60%. Lower part-load operation (<60%) would change the ratio between the airflow and fuel flow, resulting in sub-optimal combustion conditions detrimental for downstream storage systems and the economics of the oxyfuel plant (Teichgraeber, Brodrick and Brandt, 2017). New turbine designs with so-called guiding vane technology may allow for lower part-load operation (around 40%) in the constant airflow/fuel flow mode.

The thermal inertia of the ASU is the main limitation to the ramping rate of an oxyfuel combustion plant. The maximum ramp rate of an ASU is around 3% per minute, while boilers have a typical ramp rate of 6% per minute (IEAGHG, 2012). Ramp rates of up to 8% have been reported for small-plant ASUs (Alekseev, 2018), indicating upward potential. Moreover, oxygen storage can be used to increase electricity output by ramping down the ASU while maintaining full-load operation in oxyfuel mode. When based on cryogenic technology, the flue gas purification unit could suffer from disadvantages similar to the ASU.

The start-up of an oxyfuel power plant is typically conducted in air-firing combustion mode. This practice allows the boiler and steam turbine to heat up while giving the ASU time to cool down. When the different power plant components are in operation at minimum stable load, the combustion mode is changed from air to oxygen and the flue gas is recirculated. Stored oxygen from a storage tank can be temporarily used in case the ASU is not fully operational yet. When power plant load is sufficiently high, the CO_2 compressors are switched on and flue gas is fed to the CO_2 purification and compression block.

The time required to start up a large-scale oxyfuel power plant and change from air to full oxyfuel combustion mode is currently unknown. The typical start-up time for an ASU ranges from 1 to 36 hours, depending on the initial condition of the ASU (i.e. hours after shutdown) and required purity of the oxygen. However, during the start-up of the oxyfuel power systems, lower-purity oxygen can be supplied to the boiler to speed up the transient process, although the plant will not be able to remove the full amount of CO_2 (IEAGHG, 2012). Experiments with oxyfuel circulating fluidised bed (CFB) reactor pilot plants show reliable performance and start-up times of less than an hour, typically 30-45 minutes, necessary to change the oxidant streams progressively from air to flue gas with oxygen, without experiencing any operational difficulties (Espatolero and Romeo, 2017; Lupion et al., 2013).

The efficiency of oxyfuel power plants falls when operated at part load. Most of the internal power consumption is related to the ASU and CO_2 compressors. The reduction in efficiency depends heavily on the number of trains both in the CO_2 compression section and the air compression section of the ASU (see also the section on PCC). As most power plants and ASUs have multiple compressor trains, each train can be operated independently without incurring any significant efficiency losses (IEAGHG, 2012).

Flexible operation is likely to increase the cost of plant start-up and operation compared to a power plant operating in air-firing mode. However, no cost data were found in the literature.

Options to enhance flexibility

As with PCC, oxyfuel power plant operators can temporarily increase net power production by reducing internal power consumption, either for technical reasons or to optimise profit (arbitrage) by allowing the plant to follow daily or seasonal electricity grid demand patterns. Several other options can be implemented to further increase flexibility:

- **Switching boiler operation (partly) back to air-firing mode.** Although oxyfuel power plants are integrated systems designed to operate on nearly pure oxygen, they can be switched back to air-firing mode and operate reliably at both part or full load, although CO_2 would be vented to the atmosphere. Also, by tuning the flue gas recirculating flow rate, the heat distribution and combustion temperature can be influenced, thus determining the heat output of the boiler or combustion chamber, and indirectly the power output of the power plant.
- **Liquid oxygen storage.** Oxygen storage can further enhance the ramp rate, start-up time and minimum operational load of the oxyfuel power plant (see previous section), as it allows the power plant to operate independently from the ASU. The IEAGHG (2012) report shows that the electricity generation cost of an oxyfuel pulverised coal power plant and oxyfuel IGCC power plant with liquid oxygen storage is 3-8% higher than for similar configurations without oxygen storage, depending on the size (normal or smaller-sized) and operation (part vs full load) of the ASU. Revenues from the sale of additional electricity need to outweigh the additional capital costs for oxygen storage to be viable.

As for existing power plants converted to oxyfuel combustion, for both options, the increase in operating profit due to higher flexibility capabilities needs to be high enough to justify the related investment costs.

Box B.1 • CO_2 transport and storage

Flexible operation of the capture plant would also result in variations in the CO_2 flow going into the pipeline system and CO_2 storage site. Relatively little is known about the capability of pipelines and storage sites to accommodate these variations. To ensure safe CO_2 transport and storage, the CO_2 flow should stay above a certain minimum temperature and pressure level in order to avoid risks associated with changes in the CO_2 phase. Options for smoothing out CO_2 flow variations include:

- **Line-packing.** To some extent, CO_2 flow fluctuations can be balanced by changing the pressure level in the pipeline system to pack either more or less CO_2 into the pipeline – a technique called line-packing. By managing the pressure and velocity of CO_2 in this way, transport pipelines can be used as an interim store for CO_2. The balancing “capacity” of line-packing depends on multiple factors, such as the length and size of the pipeline system, pipe wall thickness and CO_2 mass flow rate (Aghajani et al., 2017).
- **Storage of compressed CO_2.** CO_2 can be temporarily stored in vessels, tanks or even underground in nearby geological sites.
- **Storage of CO_2-rich solvent.** This is the same flexibility option as described for PCC technology.

Furthermore, pipelines can be adequately designed with valves and heat insulation to control the temperature and pressure of the CO_2 flow. Line-packing could potentially be the most cost-effective option, but more research is required in this area. Storage of CO_2 was found to be more cost-effective than storage of CO_2-rich solvent. Costs for compressed CO_2 storage were estimated to raise power plant capital cost by USD_{2016} 40-54 per kilowatt (kW) (IEAGHG, 2012). All or part of these costs could be offset by reducing the size of the pipeline (and injection wells), depending on the length of the pipeline as well as on the size and variation of the CO_2 flow coming from the capture unit (IEAGHG, 2012).

Overview performance parameters of power plants with CO_2 capture

Table B.6 presents an overview of the flexibility parameters of coal- and gas-based power plants with CO_2 capture. The efficiency of power plants with a CO_2 capture system is likely to decrease when implementing flexibility options, while the electricity output and capital cost per kW increase. Overall, introducing carbon capture does not appear to affect plant flexibility. If needed, several options are available to enhance the flexibility of coal- and gas-based power plants with carbon capture. Moreover, these options can be used to produce additional electricity during grid peak demand and/or receive payment from the grid operator for primary reserve services or frequency control.

Table B.6 • Flexibility parameters of coal- and gas-based power plants with CO_2 capture

		Power plant with:					
		Post-combustion capture		Pre-combustion capture		Oxyfuel combustion capture	
Parameters		Standard technology	Retrofit with flexibility options/available new technology	Standard technology	Retrofit with flexibility options/available new technology	Standard technology [a]	Retrofit with flexibility options/available new technology
TECHNICAL							
Min. stable load (%-FL) [b]		Same as or lower than plant w/o CCS (25-50)	Same as or lower than plant w/o CCS (20-30)	Same as or lower than plant w/o CCS (35-70)	Same as or lower than plant w/o CCS (n.d.)	PC: Same as or lower than plant w/o CCS (20-30); CCGT: higher (60)	PC: Same as or lower than plant w/o CCS (20-30); CCGT: higher (60)
Max. ramp rate (%-FL/min)		Same as or greater than plant w/o CCS (3.0-5.4)	Same as or greater than plant w/o CCS (5.0-10.8)	Same as plant w/o CCS (3.0-5.0)	Same as plant w/o CCS (n.d.)	Same as or greater than plant w/o CCS (0.6-8.0)	Same as or greater than plant w/o CCS (5.0-10.8)
Start-up time to full load (min)	Hot [c]	Same as plant w/o CCS (24-127) [d]	Same as plant w/o CCS (n.d.)	Same as plant w/o CCS (420)	Same as plant w/o CCS (n.d.)	Same as plant w/o CCS (75-165)	Same as plant w/o CCS (n.d.)
	Warm [c]	Same as plant w/o CCS (68-263) [d]	Same as plant w/o CCS (n.d.)	Same as plant w/o CCS (n.d.)	Same as plant w/o CCS (n.d.)	Same as plant w/o CCS (90-263)	Same as plant w/o CCS (n.d.)
	Cold [c]	Same as plant w/o CCS (105-372) [d]	Same as plant w/o CCS (n.d.)	Same as plant w/o CCS (5 100)	Same as plant w/o CCS (n.d.)	Same as plant w/o CCS (105-450)	Same as plant w/o CCS (n.d.)
Efficiency (%) [e]	40%	PC: 0.897 x η_{FL}; NGCC: 0.699 x η_{FL}				Not possible	
	50%					Not possible	
	60%	PC: 0.949 x η_{FL}; NGCC: 0.792 x η_{FL}				CCGT: $\eta_{60\%\text{-load}}$ = 0.90 x η_{FL}	
	70%					CCGT: $\eta_{70\%\text{-load}}$ = 0.93 x η_{FL}	
	80%	PC: 0.984 x η_{FL}; NGCC: 0.891 x η_{FL}				CCGT: $\eta_{80\%\text{-load}}$ = 0.96 x η_{FL}	
Technical lifetime (yr)		Same as plant w/o CCS (35-40)	Same as plant w/o CCS (35-40)	Same as plant w/o CCS (35-40)	Same as plant w/o CCS (35-40)	Same as plant w/o CCS (35-40)	Same as plant w/o CCS (35-40)
Minimum up/down time (min)							

ECONOMIC [f]						
Capital cost (USD_{2016}/kW)	PC: 3 574 CCGT: 1 792	PC: 3 714 CCGT: 1 896	4 072	4 074	3 561	3 700
Start-up cost (USD_{2016}/MW)						
Running cost (USD_{2016}/MWh)	PC: 55 CCGT: 82	PC: 59 CCGT: 82	62	62	55	58
Fixed O&M cost (USD_{2016}/MW/yr)	PC/CCGT: 26 500	PC/CCGT: 27 450	28 400	29 300	28 400	29 300

Notes: n.d. = no data; η_{FL} = full-load efficiency; w/o = without. The numbers in parentheses refer to parameter values for power plants (both coal- and gas-based) without CCS.

[a] Liquid oxygen storage at ASU plants is already widely practised in industry and therefore assumed to be available for the standard technology.

[b] CO_2 compressors have a minimum technical operation load of 70%. However, this can be easily circumvented by installing multiple compressor trains or recirculating part of the CO_2. As power plant applications require multiple compressor trains anyway, this is not seen as a limiting factor.

[c] The terms *hot*, *warm* and *cold* are strictly speaking not correct for the oxyfuel combustion configuration, as the start-up time of this option will be constrained by the temperature of the ASU rather than by the state of the power plant.

[d] Strictly speaking the PCC system constrains the start-up time of the power-CCS system, but this can be easily circumvented by implementing one or several of the flexibility options suggested in this annex.

[e] The part-load efficiency of power plants with PCC systems is expected to be similar for retrofits and new-build plants.

[f] Cost figures were taken from IEAGHG (2017) and converted to USD_{2016}. The numbers relate to the flexibility options of solvent storage (post-combustion), oxygen storage (oxyfuel combustion) and hydrogen storage (pre-combustion). Costs for CO_2 storage that may be required to avoid variations in the CO_2 flow going to the downstream transport and storage infrastructure were estimated to raise power plant capital cost by USD_{2016} 40-54 per kW (IEAGHG, 2012). All or part of these costs could be offset by reducing the size of the pipeline (and injection wells), depending on the size and variations of the CO_2 flow size as well as the length of the pipeline (IEAGHG, 2012). CO_2 storage costs are excluded from the values presented in the table.

Sources: Brouwer et al. (2015); Cohen, Rochelle and Webber (2012); IEAGHG (2012, 2017). Cost units are converted from GBP to USD using exchange rate data from the OECD (2017).

Nuclear

Nuclear power plants (NPPs) have mainly been viewed and operated as a baseload technology, mainly because operating an NPP at its rated power level is usually more efficient, simpler and more economic. Also, in most countries, nuclear power represents a small share of the energy mix and therefore manoeuvring the plant is typically limited to safety needs (e.g. safe shutdowns in case of load rejection) and, when required, frequency regulation.

However this situation is different in certain countries, such as France, Germany, Belgium, Slovakia, Canada and Sweden (NEA, 2012; Ludwig et al., 2011). In these countries, either (i) the share of nuclear power in the national electricity mix is so important that utilities have to make use of, implement or improve the manoeuvrability of nuclear units, or (ii) flexible operation of nuclear units has been implemented to accommodate the variability of hydroelectric production or to ease the integration of variable renewable energy into the system.

The economic consequences for NPPs of load-following and flexible operations are mainly related to the reduction in the achievable load factor. The large majority of electricity generation costs for nuclear are fixed (investment or fixed O&M), and are incurred regardless of the amount of electricity generated. In comparison to other thermal plants, the share of fuel and variable O&M costs is much lower. Operating at low load factors provides little benefit by way of fuel cost reductions, while it increases markedly the average cost of electricity generated by the NPP.

Most NPPs currently operating have been designed with strong manoeuvrability capabilities, and therefore load-following (within the design margins) has no or a very small impact on the ageing of major components. However, load-following has been reported as influencing the ageing of certain operational components of pressurised water reactors (PWRs), such as valves and the control rod drive mechanisms. In addition, pressuriser inlets and outlets have reportedly required increased inspection and maintenance. Temperature transients may affect secondary systems (erosion of pipes, ageing of heat exchangers), which could lead to a slight increase in the maintenance costs. In France, Électricité de France (EDF) reports that flexible operations have slightly reduced the average unit capability factor, by about 1.2%, mainly due to unexpected or increased maintenance. It reports no impact on fuel reliability or fuel failures (EDF, 2013).

Light water reactors

Light water reactor (LWR) designs are the most common type of NPP worldwide, mostly in the form of PWRs and boiling water reactors (BWRs).[5]

Methods for varying the power output differ according to the specific type of nuclear plant. In the case of PWRs, the reactors' power level could be varied by control rod movements and/or by changing the concentration of the boric acid (neutron absorber) in the primary coolant. Operating modes have evolved significantly in the last 30 years. Boron regulation is now less used for daily power modulation since the change in the boron concentration by the chemical and volume control system is quite slow, thus limiting the achievable rate of power change. Also, boron regulation generates a considerable volume of effluent, especially toward the end of the life cycle. In a PWR, dedicated control rod banks (so-called "grey banks") are mainly used for power regulation and efficient control of power distribution.

In the case of BWRs, power regulation is performed with control rods or by changing the coolant flow rate (using the recirculation pumps) to take advantage of the negative coolant temperature coefficient; no boron regulation is used. BWRs have seen notable improvements in the design of recirculation pumps, just as the number of the control blades (per fuel bundle) and their precision have been increased.

Table B.7 • LWR performance parameters

Parameters		Commonly used	State-of-the-art
Minimum stable load		30-50%	25-50%
Maximum ramp-up		1-5% P_{ref}/min	3-5% P_{ref}/min
Maximum ramp-down		1-5% P_{ref}/min	3-5% P_{ref}/min
Start-up time	Hot	1 hour	1 hour
	Warm	2 hours	2 hours
	Cold	2 days	2 days
Efficiency	%	32	n/a
Lifetime	yr	40-60	60-80
Start-up cost	EUR/MW	50	n/a
Variable O&M	EUR/MWh	2	n/a
Fixed O&M	EUR/MW/yr	85	n/a

Note: P_{ref} = rated power.

Source: Bruynooghe, Eriksson and Fulli (2010), *Load-Following Operating Mode at Nuclear Power Plants and Incidence on Operation and Maintenance Costs – Compatibility with Wind Power Variability*; NEA (2011), *Technical and Economic Aspects of Load Following with Nuclear Power Plants*; NEA (2012), *Nuclear Energy and Renewables. System Effects in Low-carbon Electricity Systems*; Person et al. (2012), *Additional Costs for Load-Following Nuclear Power Plants*.

[5] Most of the information available on the nuclear plant flexibility refers LWRs, either PWRs or BWRs, which constitute 88% of nuclear capacity worldwide. This annex refers only to these types of nuclear power plants. Another type is the Canadian deuterium uranium (CANDU) reactor, which is not covered in this report

Limitations for power plant flexibility

Major limitations on the flexibility of NPPs are due to the physical and technical characteristics of the LWRs, which are completely different from thermal power plants (Table B.7) (Jenkins et al., 2018). In contrast to other thermal power plants that have load-following capabilities throughout their entire lifetime, the manoeuvrability of NPPs varies strongly with fuel irradiation. Manoeuvrability is maximal in the first two-thirds of the irradiation cycle, and then decreases almost linearly to reach zero at 85-90% of the fuel cycle. Nuclear units cannot be used in a load-following mode during the last 5-20% of the fuel cycle or during stretching, depending on the reactor type. Cycling and regulation are not authorised or not commonly realised in other specific conditions; for example, it is general practice not to carry out load-following on a large-scale if fuel rod failures have occurred or if some leakages have been detected in the steam generator. The in-core measuring equipment must also be recalibrated at regular intervals, usually every 60-90 days; measuring equipment calibration requires that the nuclear unit had been operated at stable power for at least 48 hours. Clearly, power cycling is not possible during those periods.

The length of time needed to reach full load is an argument often put forward to undermine the potential of nuclear reactors to follow load. It is often underlined that at least one to two days are necessary to start up a NPP and reach full power. In reality this depends on the conditions of the plant at start-up. For instance, one to two days are effectively needed after refuelling or a long-term outage. However, it takes only about two hours to achieve near full load from a hot standby state. This time requirement further decreases if the unit is kept running at house load, that is, the plant's power demand is met by its own generator and the generator remains synchronised with the grid. Run-up to full load is then possible in less than an hour.

The constraints on ramp rates exist since LWRs use control rods to adjust power output by inserting the rod into the core to reduce power and withdrawing it to increase power. This process limits the thermal and mechanical stresses on nuclear fuel assemblies, constraining ramp rates. For most PWRs in France, for example, ramp rates are generally less than 0.5% of rated capacity per minute (NEA, 2011). For modern reactors, ramp rates of around 2-5% of rated capacity per minute can be achieved on a regular basis (EUR, 2012).

Finally, it should be noted that in each country a regulatory authority defines the responsibilities of the plant operator and the safety and operational limits to be met in all operating conditions. The licensing process defines the NPP's mode of operation, as well as all types of authorised temperature transient.

Options to enhance power plant flexibility

Similar to other conventional power plants, NPP flexibility may be required for voluntary activities, including load following, frequency control and other functions that require changes in the power output, and for involuntarily circumstances, such as generation shedding and reactive power control (IAEA, 2018). New NPPs are designed to be technically capable of flexible operations. Existing plants can also be retrofitted to improve their manoeuvring capabilities for ramping, frequency regulation and operating reserves (Jenkins et al., 2018). Existing LWRs in many countries have been upgraded to improve their operational performance and manoeuvring. Retrofitting mostly involves the instrumentation and control system, in-core measurement and monitoring equipment, and the optimisation of fuel rods and pellets. NPPs now participate in primary and secondary frequency control, and some units follow a variable load programme with one or two large changes in power output per day.

At the end of the eighties, utilities from the United States, Europe and Asia prepared a set of requirements for future standard LWRs.[6] Most of the new reactors (Gen III+) are compliant with the European Utility Requirements (EUR) and Utility Requirements Document (URD) and can therefore provide flexibility services to the system. For example, according to the current version of the EUR:

- The unit must be capable of continuous operations between 50% and 100% of its rated power P_{ref}, with a rate of change of electric output of 3-5% of P_{ref} per minute.
- The standard plant design shall allow the implementation of scheduled and unscheduled load-following operation during 90% of the whole fuel cycle.
- The unit may be required to participate in emergency load variations, with a rate of change of 20% of P_{ref} per minute (decreasing) and of 1-5% of P_{ref} per minute (increasing).
- The unit shall be capable of taking part in the primary control of the grid, with a minimum range of ±2% of the rated power P_{ref}, but values up to ±5% of P_{ref} are recommended.
- The unit shall be able to contribute to grid restoration; the unit should be capable of withstanding sudden load steps up to 10% of P_{ref}.
- The standard plant design shall allow the implementation of a secondary control (optional). The minimum control range for secondary control operation shall be ± 10% of P_{ref}, with a variation rate of 1% of P_{ref} per minute. Higher values could be achieved, though not higher than 5% of P_{ref} per minute.

Most of the modern LWR designs implement even higher manoeuvrability capabilities, with the possibility of planned and unplanned load-following in a wide power range and with ramps of 5% P_{ref} (or even more) per minute. Some designs are capable of extremely fast power modulations in the frequency regulation mode, with ramps of several percent of the rated power per second, but in a narrow band around the rated power level.

Flexible characteristics of existing power plants depend strongly on reactor design and plant characteristics. Examples of NPPs with greater flexibility include:

- France (PWR -900) ramping ±2% P_{ref} per minute until 80% of the fuel cycle, ±0.2% P_{ref} per minute thereafter.
- France (PWR-1300): ramping ±5% P_{ref} per minute until 80% of the fuel cycle, 2% P_{ref} per minute thereafter.
- France (PWR-N4): ramping ±5% P_{ref} per minute.
- Germany: (PWR): ramping ±10% P_{ref} per minute for power variations less than 20%, ±5% P_{ref} per minute for power variations less than 50%, ±2% P_{ref} per minute for power variations less than 80%.
- Russian (water-water energetic reactor [VVER]-1000) ramping ±3-4% P_{ref} per minute until 70% of the fuel cycle, ±1-1.5% P_{ref} per minute thereafter.

Despite the potential flexibility of NPPs, a number of factors can influence the requirement for and value of such flexibility – most of which are context-specific. Based on Jenkins et al. (2018), total operating cost savings of the overall power system are rather moderate with the flexible operation of NPPs, which are the result of a reduction in thermal generation. Looking at the economic impact of flexible operations on NPPs, fuel costs are estimated to increase by 17-23% for BWRs and 25-34% for PWRs, based on load-following operation (IAEA, 2018). Moreover, the

[6] Examples are the Advanced LWRs Utility Requirements Document (URD) issued by EPRI in the United States and the European Utility Requirements (EUR) in Europe.

value of NPP flexibility is likely to be affected by the existence of flexibility options such as transmission grid and cross-border interchanges, storage and demand-side options (IEA, 2014b).

Biomass

A number of biomass resources can be used to generate electricity, such as agricultural waste, wood and paper industry residues, grasses and dedicated crops. Electricity generation from biomass is expected to grow significantly in emerging economies due to the low cost of agricultural residues. For example, India's Nationally Determined Contribution includes a 10 gigawatt (GW) biomass target for 2022, maximising energy access and production from bagasse generation (IEA, 2016a).

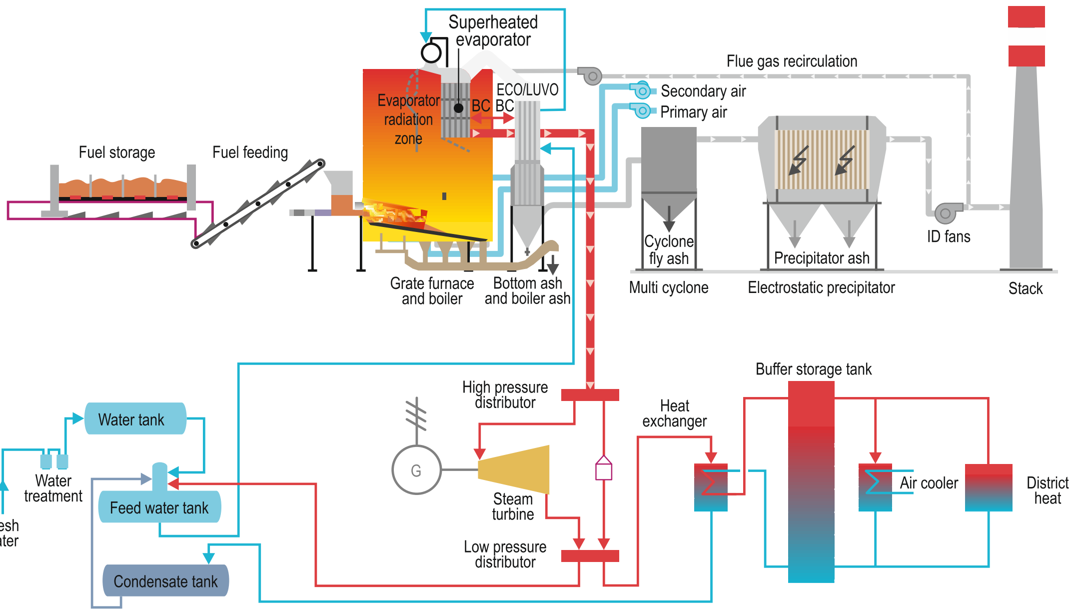
Dedicated solid biomass

Dedicated solid biomass is the main technology in this field; it involves burning biomass to produce electricity via a steam turbine in a dedicated power plant. The electricity production process resembles generation from coal-fired steam plants. In many cases this allows for the conversion of old coal plants into co-firing plants or complete conversion to biomass firing.

As with coal-fired steam plants, the flexibility limitations come in the form of the time required to heat the plant for start-up, and flame stability during quick ramping and start-ups. Characteristics of current and future plants are given in Table B.8 below.

Solid biomass plants are often operated as part of a co-generation system, which helps increase the efficiency of the system by using waste heat and steam in industrial heat processes and distributed heating networks. Figure B.4 represents the production process in a solid biomass plant with co-generation. The ability to flexibly adjust output to the power grid will depend on whether the heat and electricity output ratios of the plant are fixed.

Figure B.4 • Solid biomass steam-based co-generation



Notes: ECO/LUVO = air preheater; BC = bottoming cycle.

Source: IEA Bioenergy Task 32 (2015), "Techno-economic evaluation of selected decentralised combined heat and power (CHP) applications based on biomass combustion with steam turbine and organic Rankine cycle (ORC) processes".

Key message • Solid biomass plants operated with co-generation systems can increase overall efficiency.

Table B.8 • Solid biomass performance parameters

Parameters		Standard deployed technology	Retrofit with flexibility options	Commercially available new technology (2023)
Ramp rate in %P_r/h			30	50
Start-up time	Hours	A few hours	Less than an hour	Less than an hour
Nameplate efficiency		21-35%	23-35%	27-30%
Lifetime	Years	30	30	30
Capital cost	EUR/kW	3 300	3 000-4 000	3 380-4460
Running cost	EUR/MWh	54.5-60.3	67.6-73.5	62.6-56.3

Note: P_r = rated capacity.

Source: Weidner (2016), "Bioenergy technology factsheet".

.Limitations for power plant flexibility

Biomass power plants for the production of energy from solid biomass are designed to provide electrical power at a fixed level, to meet heat demand, or a combination of both electricity and heat. It should be noted that solid fuel co-generation plants usually have longer start-up and shutdown times than liquid- and gas-fuelled systems of comparable installed power.

Options to enhance power plant flexibility

The flexibility of existing biomass power plants can be enhanced through retrofitting: exchanging or improving existing equipment within the operating units to increase their flexibility. This includes not only hardware, but also the control system. A retrofit may involve redesigning boiler components for which the high-temperature corrosion (HTC) load would be too high. The flexibility of new biomass plants can be increased by designing superheaters with low heat flux and by employing materials with high HTC resistance and non-compact geometry (Ramboll, 2011).

At a broader level, experience demonstrates that the flexibility of the solid biomass fleet can be improved with a two-pronged approach: increasing the flexibility of larger units with methods analogous to those for large-scale fossil-fuelled power plants, while using small and decentralised units to provide grid support from the bottom.

Multiple options are available to improve the flexible operation of biomass power plants, depending on the technology used. For example, a common way to provide downward ramping in steam-cycle power plants is bypassing steam around the turbine, providing additional heat to heat grids or storage facilities. Additionally, some technologies (e.g. furnaces with a stoker spreader) are capable of easily reducing the combustion load. Decoupling heat and power production using heat accumulators can also ensure flexible operation.

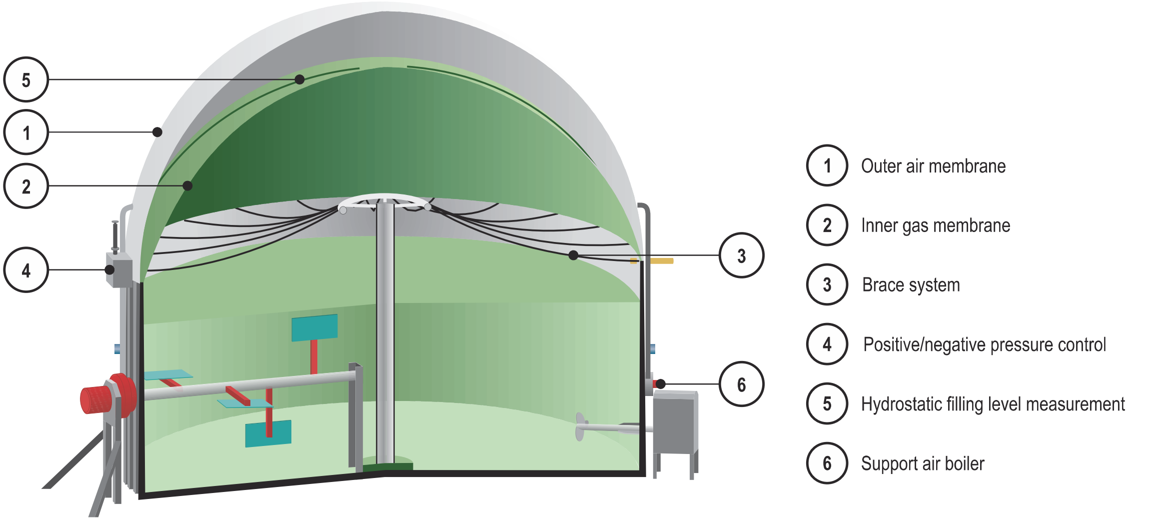
Combined heat and storage enables additional revenue streams to compensate for reduced output in flexible systems. This is particularly relevant in systems where cold seasons coincide with reduced VRE output.

Biogas

Electricity can be generated from the combustion of biogas produced by breaking down and digesting organic material. This may include food and drink waste, processing residues from bakeries or breweries, agricultural residues such as manure and slurries, crops grown specifically for biodigestion and sewage sludge. The most common type of biodigestion plant is the "wet" digestor, where a liquid sludge is fed into an anaerobic chamber for fermentation. Designs such as the continuous stirred-tank reactor (CSTR) shown in Figure B.5 below rotate the sludge at intervals in order to avoid the build-up of floating layers or bacteria agglomerates. The gas resulting from biodigestion can be used for electricity production or alternative applications, such as heat generation or storage in the gas network following upgrading (Weidner, 2016).

Means of improving biogas system flexibility include increasing volumes of gas storage and generator capacity, adapted feeding regimes to control gas production and the integration of multiple smaller systems in virtual power plants.

Figure B.5 • Structure of a CSTR

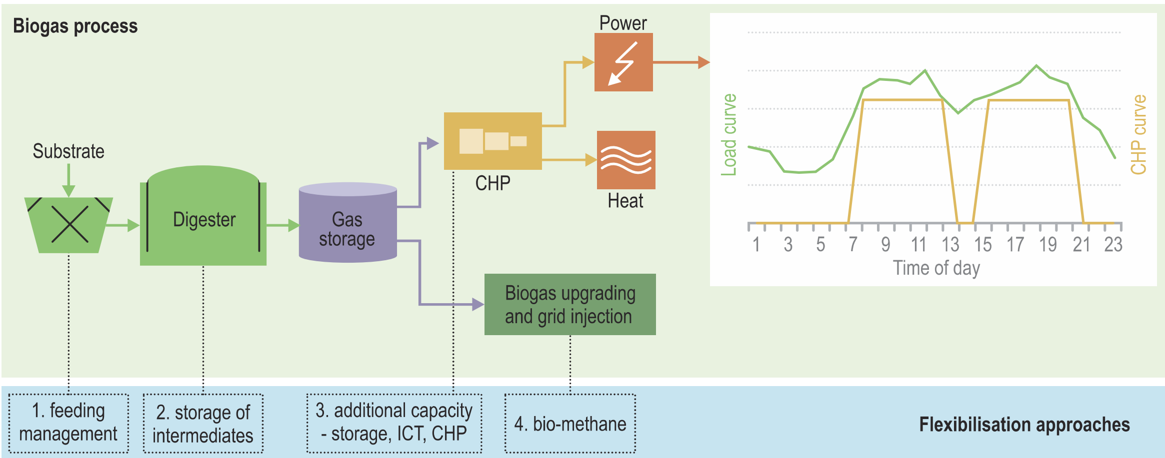


Source: Liebetrau et al. (2015) in Barchmann et al. (2016), "Expanding the flexibility of biogas plants – substrate management, schedule synthesis and economic assessment".

Key message • CSTR with integrated double-membrane gas storage.

A number of operational adjustments are available to increase the flexibility of demand-driven anaerobic digestion systems with co-generation (Figure A.6). These can take place in most steps of the production chain, through the fermenter, digester, gas storage and ultimately through biogas upgrading for injection into the gas network, if enabled.

Figure B.6 • Approaches for biogas-based demand-driven power production



Notes: CHP = combined heat and power; ICT = information and communications technology.
Source: Szarka et al. (2013), "A novel role for bioenergy; a flexible, demand-oriented power supply".

Key message • The point at which the operational change takes place will influence the time horizon of the flexibility provided by the biogas plant.

The scale and operational flexibility of biogas facilities are typically limited by non-power constraints such as local feedstock resource availability, volume of gas storage and the required parameters for biological process stability (Table B.9).

Table B.9 • Biogas performance parameters

Parameters		Standard deployed technology	Standard technology with flexibility retrofit
Start-up time	Hot	Gas turbine: 3 minutes Biogas: 5 days*	n/a
	Warm	n/a	n/a
	Cold	Gas turbine: 3 min Biogas: 30 days**	n/a
Efficiency		40%	n/a
Lifetime	Years	10-25	n/a
Capital costs	EUR/kW	4 000-5 500	5 000-5 500
Running costs	EUR/MWh	96-125	n/a

* Hot start of biogas equipment implies time necessary for gas production with active biomass at 38°C, many days without substrate supply.

** Cold start of biogas equipment implies time necessary for gas production with active biomass at 20°C.

Source: Weidner (2016), "Bioenergy technology factsheet".

Limitations for power plant flexibility

The degree of flexibility is constrained by the amount of gas storage present on site. Consequently, the aggregation of biogas facilities is critical to making a notable contribution to grid services.

The scale of the connected biogas plants and local resource availability are usually the constraints on the amount of grid support or relief that can be provided by bioenergy.

For the biodigestion processes, changes in gas production depend on the sensitivity of the digestion process to modification of the feeding regime. However, high capital investment typically requires biogas plants to operate at high full-load hours. In this sense, reducing power output can lead to a stark increase in the plant levelised cost of energy (LCOE).

Additional investment may be required to enable plant flexibility through retrofits or at the planning stage. Participation in ancillary services may be an option to complement biogas plant income streams, allowing investment in surplus generator or storage capacity as well as retrofits.

Biogas plants have higher marginal costs than VRE, such that they will compete with gas and hydro in the provision of balancing services.

Current systems of uniform feed-in tariffs often fail to provide an incentive for flexibility. "It can be argued that support systems should be adapted to benefit producers who adjust the rate of electricity production according to periods of high demand or according to specific needs of the electricity grids." (Persson et al., 2014).

Options to enhance power plant flexibility

Bioenergy plants are ideal candidates for grid convergence and participation in additional ancillary services allows for greater revenue streams. The measures presented below can help improve flexibility in operating biogas plants.

Feeding management: Adapting the substrate feeding regime can be used to decrease biogas generation. This can be useful for reducing the electrical output of the plant without needing to invest in additional gas storage, thus avoiding the need for further investment. A study by the German Centre for Biomass Research showed that it is possible to adjust the ratios of different types of feedstock in order to adjust biogas production according to electricity prices over specific periods. Depending on the type of feedstock, the necessity for additional gas storage can be reduced by more than 60% in comparison to common constant feeding operations (Mauky et al., 2017). This may, however, require some investment to modify the feeding equipment (Szarka et al., 2013).

Storage of intermediates: The first stage of biodegradation yields intermediate products such as amino acids, sugars and fatty acids. These can be separated and stored for later use when increases in gas generation and power output are desired.

Upgrading co-generation for increased storage: Upgrading co-generation capacity can help increase on-site gas and heat storage capabilities and decrease electricity production at times of low demand. This can be beneficial for plants providing both heat and power. As with other co-generation technologies, it is key to be able to vary the ratios between both heat and power outputs to ensure flexibility when the demand for either of these outputs is lower. These measures are more capital intensive, but benefit from greater provision of flexibility and are incentivised in countries such as Germany (Szarka et al., 2013)

Biogas upgrading and grid storage: In Germany most biogas co-generation plants operate on raw biogas (Persson et al., 2014). Additional gas output can be stored in the local gas grid after being subject to biogas upgrading processes. It can then be retrieved by the same plant or utilised in larger gas turbines for balancing. This provides scope for indirect VRE balancing. Such uses, however, are mainly driven by certificate systems to track biomethane use rather than providing flexibility. A technical option for balancing the system is to upgrade the biogas with surplus hydrogen when electricity demand is low (Arasto et al., 2017).

Flexibility through aggregation: A typical barrier to bioenergy providing flexibility is that the appropriate revenue streams are not accessible due to regulatory requirements and the small scale of bioenergy plants. Virtual plants can aggregate the output of several small-scale bioenergy generators to deliver grid services, while meeting the minimum volume, duration and accuracy requirements of system operators. In this case the need for costly investment in local storage capacity is replaced by investment in smaller, cheaper monitoring and control equipment.

Hydropower

Hydropower technology is a highly flexible source of electricity. It has flexible operating characteristics including rapid ramping, quick start, low minimum stable level and black-start capabilities, and these can be important providers of grid flexibility. In addition, hydropower plants can provide system services to maintain the reliability of the power system, including reactive power, inertia and frequency response. They can also operate as synchronous condensers, which can provide reactive power support and voltage stability to the power system. Another main benefit of hydropower is its low cost of energy due to zero fuel costs. The three types of hydropower are reservoir, pumped storage hydro (PSH) and run-of-river.

With higher penetrations of VRE, hydropower is becoming more valuable due to its flexible operating characteristics, which can help balance supply and demand in a reliable and cost-effective manner. This flexibility allows hydropower plants to contribute to the power system by reducing the extent to which conventional generators have to cycle up/down and start/stop, particularly with increasing VRE penetration.

However, it is recognised that the operation of hydropower plants, and thus their flexibility, can also be limited because hydropower developments are generally multipurpose. They are not only for power production, but also for water management in the context of the water/energy nexus (IEA Hydropower, 2017). Non-power-related constraints include irrigation and environmental protection, which are highly site-specific as well as context-specific.

Reservoir hydropower and PSH provide bulk power services, as per the energy volume and energy option concepts described in Chapter 2. In addition they can also provide energy or price arbitrage in the electricity market. Large reservoir and PSH plants are the focus of this section. Run-of-river plants are generally excluded since they have limited storage and depend on natural flows, although many larger run-of-river plants can have significant short-term storage, which can provide flexible generation.

Large hydropower with reservoir

Depending on long-term system needs, reservoirs can have months to years of water storage, allowing these hydropower facilities to provide very stable and accessible storage reserves and flexibility services. As previously explained, hydropower with reservoir can provide system inertia and frequency regulation in the very short- and short-term timescale. In addition it can provide voltage support. The important performance parameters for hydropower include minimum stable load, ramp rates, operating costs and start-up costs (Table B.10).

Table B.10 • Large hydropower performance parameters

Parameters		Standard deployed technology
Minimum stable load		0-30%
Maximum ramp-up		0-100% in 5 minutes
Maximum ramp-down		0-100% in 5 minutes
Ramp rate at varying output levels	At 50%	Unchanged
	At 100%	Unchanged
Forced outage		<2%
Lifetime	Years	80+ years
Minimum uptime	Minutes	5
Minimum downtime	Minutes	5
Start costs	EUR/MW	340
Running costs	EUR/MWh	14
Fixed O&M	EUR/MW/yr	35-85

Sources: IEA ETSAP (2010), *Hydropower*; IEA Hydropower (2017), *Valuing Hydropower Services: The Economic Value of Energy and Water Management Services Provided by Hydropower Projects with Storage*; US Department of the Interior (2014), *Hydrogenerator Start/Stop Costs*; Eurelectric (2011), *Hydro in Europe: Powering Renewables.*

Limitations for power plant flexibility

Hydropower flexibility in the power system can be limited by other water management constraints in multipurpose developments: irrigation, navigation, flood control, recreation and environmental requirements. Power production is sometimes a lower priority for relevant official organisations, particularly water irrigation departments. However, hydropower production is often important as the provider of electrical energy and revenue that supports the other services.

Annual and multiyear water cycle behaviour and weather patterns are another factor that can limit the flexibility of hydropower plants. These aspects can dictate reservoir levels and thus power system capabilities. For example, long-term droughts may substantially reduce available rated power and hence hydro flexibility.

Additionally, while the machinery in a hydropower plant might be perfectly capable of rapidly increasing output, the bottleneck may be found in the dam's tunnels, which may push the plant to run constantly regardless of system needs. Similarly, the ability to rapidly increase output may be hindered by the interconnection capacity. This limitation is particularly relevant for Norwegian power plants exporting to Europe (IEA Hydropower, 2017).

Options to enhance power plant flexibility

While large hydropower with reservoir has the potential to provide a lot of flexibility, operation is sometimes curtailed by water management constraints. However, options are available to overcome or at least cope with the non-power-related constraints that prevent hydropower plants from achieving their full flexibility potential. One such option is an integrated planning process that incorporates irrigation requirements into generation planning in order to recognise and understand the non-power related constraints. This requires proper co-ordination with water irrigation departments.

PSH

PSH plants store energy by using the differential in hydraulic head between multiple reservoirs that are situated at different heights (Vennemann et al., 2011). Generally, PSH plants operate in pump mode when electricity demand is low; excess generation is stored by pumping water from lower to higher reservoirs with pumping efficiencies of around 70-85% (Hunt, de Freitas and Pereira Junior, 2017). At times of high electricity demand, or when it is necessary to balance VRE or provide grid services, this water is released to drive the turbines for electricity generation. The technology is the most established utility-scale method for electricity storage, comprising more than 99% of the world's storage capacity. Plants can operate reversible pump-turbines or two separate turbines and pumps. These can be inflexible single speed or variable speed.

PSH can be an important source of flexibility in the power system. In addition, it is considered a cost-effective option once it is built. Its characteristics not only allow PSH to provide or absorb energy based on the need of the grid (Table B.11), but also make it capable of providing system services including black-start capability, ramping, quick start, spinning reserve, reactive power, inertia and frequency regulation.

A PSH plant's flexibility is also determined by the change-over time from turbine generation to pump mode, and its ability to provide system services in both generation and pump modes.

Table B.11 • PSH performance parameters

Parameters		Standard deployed technology
Minimum stable load		33%
Maximum ramp-up		50%/minute
Maximum ramp-down		50%/minute
Ramp rate at varying output levels	At 50%	See above
	At 100%	See above
Lifetime	Years	60
Minimum uptime	Minutes	n/a

Minimum downtime	Minutes	n/a
Start costs	EUR/MW	n/a
Running costs	EUR/MWh	0.0-0.3
Fixed O&M	EUR/MW/yr	12 085*-25 200*

* Include replacement cost; average of given figures.

Source: Sandia National Laboratory (2015), *Electricity Storage Handbook*, www.sandia.gov/ess/publications/SAND2015-1002.pdf; Black and Veatch (2012), *Cost and Performance Data for Power Generation Technologies*, www.bv.com/docs/reports-studies/nrel-cost-report.pdf).

Limitations for power plant flexibility

The flexibility of PSH depends on the technology used: conventional synchronous reversible pump-turbine, reversible variable-speed pump-turbine, or ternary machine set consisting of one motor-generator, one turbine and one pump. These technologies can be ranked from lowest (conventional synchronous reversible pump) to highest flexibility (ternary machine).

Most existing facilities have relatively inflexible single-speed pumping systems, meaning input power is constant and the change-over times from turbine to pump and vice versa can be an issue. However, projects developed during the past decade often use the new designs of variable-speed or ternary systems. These provide additional input power flexibility in the form of rapid change-over times between generation and pump modes, although they have higher capital cost (cost of a plant with a single-speed turbine is USD 550/kW, and with a variable-speed turbine is USD 650-USD 750/kW).

Options to enhance power plant flexibility

PSH plants dedicated exclusively to power production and energy services can offer greater flexibility. With this technology, water can be cycled from upper to lower reservoirs as needed, as long as doing so is economic. Large reservoirs allow energy arbitrage across days, weeks, or even months. Water can be pumped during low load/price seasons for frequent use in high load/price seasons.

Certain PSH plants can operate in a special model called hydraulic short-circuit pumped storage (HSCPS). This mode of operation is possible in ternary pumped storage units where the turbine and pump are located on the same shaft, equipped with a coupling unit. This allows for quick transition between pumping and generation without requiring rotation reversal, enabling the plant to provide inertia and frequency response. The ability to seamlessly shift between turbine and pump mode provides greater flexibility to the grid (IEA and 21CPP, 2017). HSCPS has been applied in hydropower plants in Austria, Switzerland, the Canary Islands and Wales.

Closed-loop PSH developments are also increasingly being considered as they have a smaller footprint and lower environmental impact. Rather than using an existing body of water for the upper and/or lower reservoirs, such as a river, lake or reservoir, the two reservoirs are purpose-built without any inflow or discharge, and are filled by pumping in from another source. Once the system is charged, the storage capacity of closed-loop sites can be dedicated to serving flexibility needs, while requiring occasional reservoir replenishment due to seepage or evaporation.

A specific application of the closed-loop system is to use deep excavations from exhausted mines. In a limited number of cases, deep mines have been targeted as a potential lower reservoir for pumped storage. These can provide a specific off-river closed-loop PSH opportunity with even lower construction costs.

Wind

Wind plants capture the kinetic energy in moving air to turn blades that then spin a generator to produce electricity. Turbine blades, like aircraft wings, create higher pressure under the blade than above it, resulting in the blade rotation. Most land-based wind turbines currently use a three-blade design with the rotor placed 80-160 metres above the ground and have a generating capacity typically in the range of 1.5-4 MW. Offshore turbines can be even larger and typically capture higher-quality wind streams. In Europe alone in 2017, 88% of newly built offshore wind turbines had an average capacity of 6 MW (WindEurope 2017). Most turbines incorporate controls to keep the blades pitched and directed into the wind at levels to achieve maximum and safe electricity generation. The rotor is connected, either through a gearbox or directly, to a generator. The electrical output from all turbines in a given plant (or farm) is integrated at a substation and then connected to the grid. As turbine tower heights have grown in recent years, average capacity factors of new wind plants have also risen. The performance characteristics of current and future plants are provided in Table B.12 below.

Table B.12 • Turbine performance parameters

Parameters		Standard deployed technology	Commercially available new technology
Minimum stable load		Zero	same
Maximum ramp-up		>100% of capacity/minute (assuming ramp-up headroom exists)	same
Maximum ramp-down		>100%/minute	same
Ramp rate at varying output levels	At 50%	>100%/minute	same
	At 100%	0% up, >100%/minute down	same
Forced outage		5%	same
Lifetime	Years	20-35	same
Start-up cost	EUR/MW	Zero or n/a	same
Running cost	EUR/MWh	5-15	5
Fixed O&M	EUR/MW/yr	30 000-45 000	30 000

Note: >100% capacity/minute means the unit can ramp from zero to full output in less than one minute, but appropriate wind speeds must be available.

Source: Stehly, Heimiller and Scott (2016), *Cost of Wind Energy Review*, www.nrel.gov/docs/fy18osti/70363.pdf; EIA (2018), *Cost and Performance Characteristics of New Generating Technologies;* Black and Veatch (2012), *Cost and Performance Data for Power Generation Technologies*, www.bv.com/docs/reports-studies/nrel-cost-report.pdf; Gevorgian and O'Neill (2016), *Advanced Grid-Friendly Controls Demonstration Project for Utility-Scale PV Power Plants*, www.nrel.gov/docs/fy16osti/65368.pdf.

Limitations for power plant flexibility

Wind resource is typically variable in most locations and power output can thus fluctuate over a variety of timescales. As wind plants have no fuel costs, operators typically dispatch them at full available output depending on wind conditions. Other generators, and the demand side, therefore typically need to accommodate the variable generation from wind.

Advanced forecasting techniques can significantly reduce the error between day-ahead forecasts of wind output and actual availability nearer to real-time generation. This helps minimise the cost of keeping supply and demand in balance, and informs system operators of how much operating reserve should be made available. Other operational practices can affect the need for flexibility to facilitate wind generation. Distributing wind plants over large geographical areas can minimise the coincidence of changing wind speeds and provide more uniform output at the system level. Using sub-hourly scheduling and dispatch intervals also improves overall operational efficiency.

Wind turbines can typically curtail generation when needed (and lose revenue in the process), but can only increase generation if they are operating below maximum output (again, losing potential revenue). When wind turbines are operating below maximum output – perhaps due to thermal plants already operating at their minimum generation levels, for example – ramping up generation is possible if wind conditions allow, and they can contribute important services to the grid. Sophisticated electronics can provide voltage control, reactive power and frequency response, but only if system operators understand and reward the value they can provide and have them enabled.

Options to enhance power plant flexibility

Wind turbine technology has become much more sophisticated over the past 10-15 years, with more advanced electronics, taller towers, larger blades, and longer-lasting gearboxes and rotors. Greater capacity factors are a driving factor in improving balancing and forecasting of wind energy output (IEA, 2016b). These improvements are likely to continue, although land-based turbines face logistical transport barriers as components grow in size. One way to overcome these challenges is through on-site manufacturing of towers and blades, perhaps using additive manufacturing or three-dimensional printing.

In addition to continuously improving forecasting techniques that help inform the need for system flexibility, system operators are likely to continue expanding their knowledge of planning and operational practices available to integrate wind power into the grid (Cochran et al., 2012; IEA, 2017b). Offshore wind turbines are likely to continue expanding in size and capacity; as a result, their capacity factors are likely to increase, although this does not eliminate the need for greater system flexibility as uncertainty in output still remains.

Wind plants now have the ability to provide important grid services, including synthetic inertia, governor response and regulation. They are currently not often required to do so, however, and provision of these services can involve trade-offs. Additionally, power converters can provide several grid services that aid the integration of wind, including frequency and voltage disturbance ride-through, voltage and ramping control, and reactive power control. Still, increasing amounts of variable generation such as wind introduce uncertainty that grid operators must understand and manage.

The development of new strategies for turbine output and farm output management also offers promising prospects for increasing delivery of flexibility from wind. Depending on system needs, single turbines can momentarily increase output by extracting kinetic energy from the rotor and delivering synthetic inertia. However, providing synthetic inertia in the subseconds to seconds timeframe may represent a trade-off in the form of lower output stability in the seconds to minutes period. Other alternative mechanisms include continuous derating for the provision of upward and downward regulation as opposed to using Available Active Power (AAP) to establish benchmarks for deliverable downward regulation without compromising power output (see case study in Box B.2 below). Lastly, some wind farm strategies entail the derating of the first turbine. This allows the turbines behind it to operate at higher output as less energy is taken from the wind. As a whole, this allows for the provision of both upward regulation from the derated turbine, while foregoing revenue losses as the other turbines compensate with extra output.

Box B.2 • Advanced downward regulation from wind power

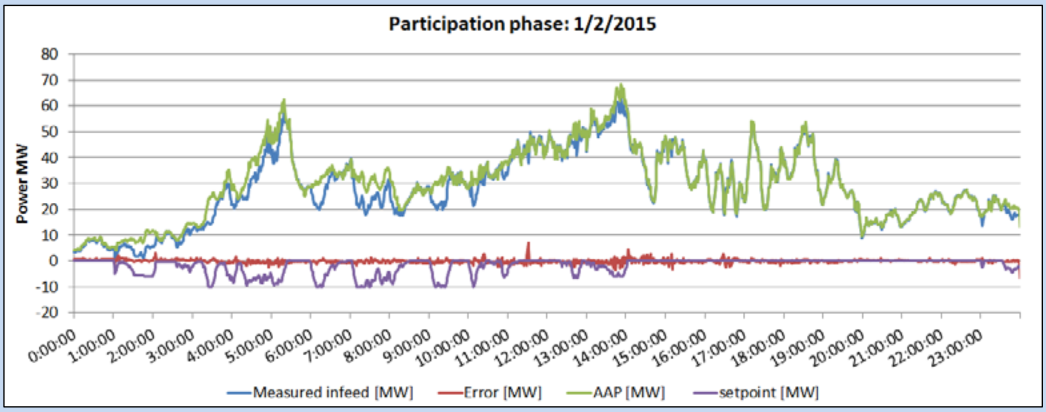
In Belgium, the pilot introduction of an advanced monitoring and management mechanism called the Available Active Power (AAP) mechanism allows for the measurement of downward regulation with respect to a theoretical maximum output based on the wind speed at the time of output curtailment. This has been introduced in a response to the goal of achieving 8 000 MW of installed VRE capacity in Belgium by 2019, which comes with increased variability and limited predictability.

So far, most precontracted reserve capacity has been provided by gas-fired power plants (CCGTs). However, the market conditions for these have declined over time, resulting in high must-run costs for the provision of regulation services such as frequency containment reserves and automatic frequency restoration reserves (aFRR).

The pilot related to the Estinnes wind farm, operated by WindVision, with a total capacity of 81 MW. It focused on the provision of downward aFRR capacity using the AAP mechanism in order to avoid continuous derating, as the latter would result in a significant loss of green certificates.

The introduction of the AAP mechanism allows for a real-time estimation of the baseline, based on the wind conditions – updated every 4-5 seconds – and the technical characteristics of the wind farm. The baseline is then used as a reference infeed from which the aFRR delivery is estimated. The main benefit of this approach is the possibility of avoiding the continuous derating of the wind turbines. Figure B.7 is just one example of the performance of the Estinnes plant in Belgium in delivering aFRR, which highlights the benefit of using the AAP mechanism.

Figure B.7 • Performance of Estinnes wind plant in delivery of aFRR



Source: Elia (2015), "Delivery of downward aFRR by wind farms," www.elia.be/~/media/files/Elia/users-group/task-force-balancing/Downward_aFRR_windfarms_EN_2015.pdf.

Figure B.8 highlights continuous derating of a wind plant using the schedule mechanism and the benefit of using the AAP mechanism for the provision of downward aFRR.

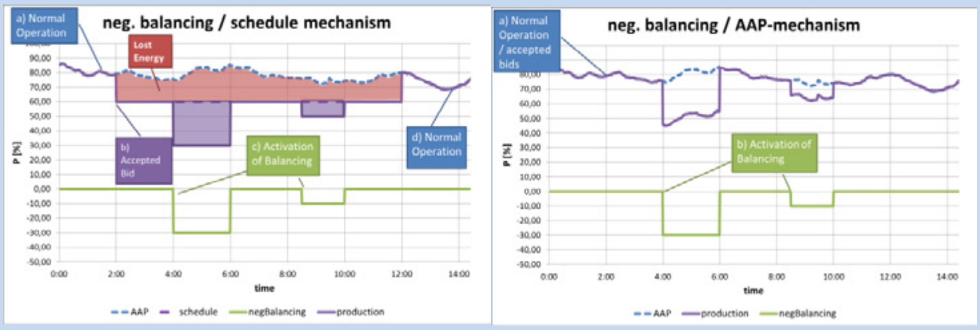
Accuracy under curtailment depends on the "wind farm effect". Curtailing one wind turbine will increase the speed of other turbines downstream as less energy is withdrawn from the wind. Therefore changes in output must be co-ordinated across the whole plant. Nonetheless, using APP to avoid continuous derating may decrease the need to provide compensation to wind park operators for foregone revenues.

The deployment of AAP mechanisms for wind generation flexibility has been tested in further systems:

- In Ireland the overall MW availability signal is calculated for a controllable wind farm power station using the AAP mechanism. One way to calculate the AAP signal could be as follows. At each wind energy convertor (WEC), an individual availability signal is calculated as a theoretical value based on its current aerodynamic and electrical operating points, to show the power that the WEC could generate if it were not limited via the transmission system operator (TSO) set point. The supervisory control and data acquisition (SCADA) server collects and summates the availability signals generated at WEC level to generate a single, overall AAP signal for the TSO interface. This overall AAP signal takes into account any technical and "force majeure" limitations such as internal WEC faults (over-temperature, etc.), sound/shadow curtailments, storm control (power reduction due to high wind speed), and grid voltage/frequency trips, such that the calculated AAP signal is reduced when any such limitation is in force.

- The German TSOs set up a pilot project in 2015 for the supply of negative manual frequency restoration reserves (mFRR) by wind for the balancing market. Enercon, a wind turbine manufacturer, decided to participate in this pilot with a 300 MW pool of wind power plants. These are integrated into a new dispatch system that connects the TSOs to the wind power plants and enables the aggregator to offer mFRR from wind power plants. New technical developments were necessary to include wind power plants in the balancing market via the AAP mechanism and allow a wind power plant to follow mFRR setpoints. The AAP signal could also be used as a basis for compensation by calculating lost energy due to congestion management.

Figure B.8 • Illustration of the schedule mechanism and the AAP mechanism



Source: Elia (2015), "Delivery of downward aFRR by wind farms," www.elia.be/~/media/files/Elia/users-group/task-force-balancing/Downward_aFRR_windfarms_EN_2015.pdf.

Key point • Real-time measurement of potential output through the APP mechanism prevents continuous derating of wind turbines.

Source: Case study information provided by Enercon.

Solar

Utility-scale photovoltaics

Photovoltaic (PV) modules convert sunlight directly into electricity using semiconductors. A variety of silicon, thin-film and more novel PV technologies exist and are under development, although silicon technologies represent over 90% of current global market deployment. PV modules can be stationary (fixed), track along a single axis, or track along two axes. The capability of tracking the sun increases the power output of modules, but also incurs increased capital and operational costs. PV output, relative to insolation level, can also decline in regions with high temperatures, or where dust or snow accumulation is significant. Utility-scale PV plants typically range in size from a few to hundreds of megawatts. According to Lazard (2017), the LCOE of utility-scale PV declined by 86% between 2009 and 2017, accounting for its rapid growth around the globe. In 2017, China led all countries by installing 53 GW of solar, much of it at the utility scale.

PV modules typically have an expected lifespan of 25 to 40 years. The inverters – which convert direct current (DC) power from modules to alternating current (AC) power to match the grid – typically have an expected 15-year lifespan, although a majority of solar installations have been constructed within the past 5 years, so there are limited empirical data on actual lifespan and performance. The performance characteristics of current and future plants are provided in Table B.13 below.

Table B.13 • PV performance parameters

Parameters		Standard deployed technology
Minimum stable load		Zero
Maximum ramp-up		>100% of capacity/minute (assuming ramp-up headroom exists)
Maximum ramp-down		>100% of capacity/minute
Ramp rate at varying output levels	At 50%	>100%/min
	At 100%	0% ramp-up, >100% ramp-down
Forced outage		0%
Lifetime	Years	25-40
Minimum uptime	Minutes	n/a
Minimum downtime	Minutes	n/a
Start-up cost		0
Running cost		0
Fixed O&M	USD/kW-yr	One-axis tracker: 18.5; fixed-tilt: 15.4

Note: >100% capacity/minute means the unit can ramp from zero to full output in less than one minute.

Sources: NREL (2017), *US Solar Photovoltaic System Cost Benchmark: Q1 2017*, www.nrel.gov/docs/fy17osti/68925.pdf; LBNL (2016), *Utility-Scale Solar 2016: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States*, https://emp.lbl.gov/publications/utility-scale-solar-2016-empirical; Black and Veatch (2012), *Cost and Performance Data for Power Generation Technologies*, www.bv.com/docs/reports-studies/nrel-cost-report.pdf; NREL (2016), *Advanced Grid-Friendly Controls Demonstration Project for Utility-Scale PV Power Plants*, www.nrel.gov/docs/fy16osti/65368.pdf.

Limitations for power plant flexibility

Like wind, utility-scale PV is considered a variable generation technology and can only produce power during daylight hours. Output from modules is dependent on the time of year, weather conditions and any accumulation of material (dust, snow) on top of the modules. Clouds can significantly affect production as well. As with wind plants, PV operators typically dispatch all power available, since fuel costs are zero, and allow other generators and the demand side to adjust accordingly.

Advanced forecasting techniques may be less mature for PV than they are for wind, but can also assist in addressing flexibility needs. Maximum PV production occurs for a few hours before and after solar noon (the period when the sun appears directly overhead), which may coincide with periods of high electricity demand during the day, especially in the summer when cooling loads are elevated. At high PV penetration levels, peak net load has shifted in some places to late afternoon or early evening, which has resulted in a need for any existing large thermal generators to ramp up when the sun starts to set.

For thermal generators designed to operate at a consistent output, more frequent output cycling can result in increased maintenance costs and reduced life. While the magnitude remains limited, solar PV is increasingly being used with battery storage, which can help address shifts in peak demand and some of the resource's variability concerns. Many other planning and operational changes can help integrate solar PV into the grid at lower system costs than storage.

PV systems can continue to operate normally ("ride-through") for a limited time when disturbances occur and the grid's voltage or frequency operates outside predetermined ranges. The grid may be able to recover if the disturbance is small or short-lived. However, if inverters are not programmed to operate during disturbances, PV systems can disconnect, although this phenomenon is primarily limited to distributed systems and not utility scale.

Options to enhance power plant flexibility

PV modules produce DC power, so inverters are needed to convert output to AC and feed the electricity into the grid. Many utility-scale PV plants now have the potential to deliver a variety of services to the grid that assist with flexibility, although they are often not called on to do so. These services include ride-through from frequency and voltage disturbances, voltage and ramping control, and reactive power control. Inverters can also limit their active power output and control their ramping to maintain system stability.

Voltage and ramping controls can be programmed as a function of grid conditions or can be triggered remotely. Stakeholders – including system operators, plant owners, utilities, manufacturers and regulators – may all have their own reasons for not taking greater advantage of the services that PV plants can provide to the grid, as described in NREL (2016).

The increased use of battery storage also affects the ability of utility-scale PV to offer flexibility improvements. While solar and battery storage systems can provide a broad range of services, ranging from arbitrage to regulation to voltage control, they may not be encouraged to do so by market design rules in many jurisdictions. These are likely to change if battery costs continue to decline. In the United States, the release of Order 841 by the Federal Energy Regulatory Commission (FERC) is expected to give a boost to PV with storage by recognising its system value in two ways. First, regional and independent system operators are required to facilitate the provision of capacity, energy and ancillary services each resource technology is technically able to provide. And second, they are required to execute all storage transactions at local marginal price (FERC, 2018)

Box B.3 • Improved PV flexibility for ancillary services

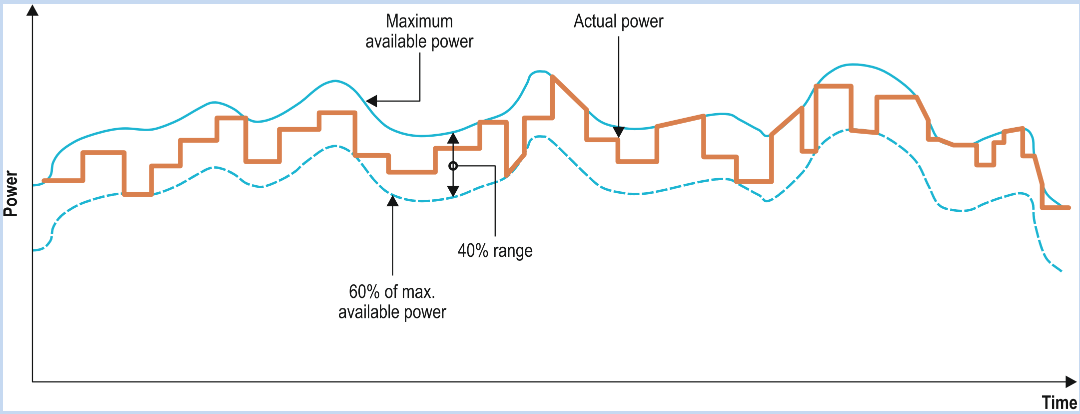
AES Corporation's 20 MW Ilumina PV power plant is located in Guayama, Puerto Rico, and has been operating commercially since 2012 under a long-term power purchase agreement with the Puerto Rico Electric Power Authority (PREPA).

The US National Renewable Energy Laboratory (NREL), AES Corporation and PREPA conducted a pilot demonstration project on this PV plant to test the viability of providing ancillary services through system-friendly controls. The project was funded by US Department of Energy's Solar Energy Technologies Office, including the cost of retrofitting the power plant controller to optimise functionality, as well as paying the plant owner for lost revenue due to curtailment for the demonstration. PREPA indicated that its primary interest was the testing of active power control by PV. In particular, PREPA was interested in renewable power plant participation in frequency regulation and automatic generation control (AGC), and providing ultra-short-term flexibility through fast inertia-like frequency response to arrest rates of grid frequency decline during system contingencies.

Before any retrofit intervention, the PV power plant controller was already able to essentially follow the actual electrical frequency in real time. Then the plant power set point could decrease the plant's output when frequency moved higher than the dead band (±0.02% of nominal frequency). However, because the plant was operated at the maximum power output, it could not contribute to raising the system frequency by increasing its power output. The demonstration changed that performance by estimating the maximum potential output, decreasing the actual output by a set percentage, and communicating that potential to the PREPA control centre. Tests included all time frames: fast frequency response, droop response and AGC.

As part of the pilot demonstration activities, the power plant controller was upgraded to provide a continuous estimate of the plant's output potential to the controllers and decrease the plant output. Communication equipment and protocols were also modified to communicate the potential for increasing PV output (i.e. the "headroom") to PREPA.

Figure B.9 • PV output management for upward and downward regulation



Source: Gevorgian and O'Neill (2016), *Advanced Grid-Friendly Controls Demonstration Project for Utility-Scale PV Power Plants*, www.nrel.gov/docs/fy16osti/65368.pdf.

Key point • Actively decreasing the plant's output and comparing it to the total potential output can allow PV plants to provide measurable ultra-short-term upward and downward flexibility by responding to real-time frequency variations.

The plant demonstration improved performance for the Puerto Rico system in that the plant could operate as regulation in both upward and downward directions (Figure B.9). Because PREPA had information on plant capability (as computed by dispersed pyranometers at the plant site), it could prioritise the Ilumina plant for frequency response and keep traditional providers of this ancillary service on standby. Importantly, this was a demonstration project so there was no revenue associated with the service provision. Further work could assess the feasibility of such schemes for plants in power purchase agreements and how to provide the appropriate market signals to incentivise plant operators to participate in the provision of flexibility services.

Source: case study provided by NREL.

Concentrated solar power

Concentrated solar power (CSP) plants, unlike solar PV plants, employ thermal energy to convert sunlight into electricity. Reflective collectors direct solar radiation to a receiver, transferring the energy to a heat transfer fluid. This heat transfer fluid converts water to steam, powering a steam turbine to produce electricity. CSP can also be combined with thermal energy storage (TES) to store the thermal energy for use when the sun is not shining. It is this integration with TES that makes CSP a unique source of solar energy in that CSP-TES can be considered a dispatchable resource that can discharge electricity, decoupled to some extent from solar availability. However, CSP-TES is still an energy-limited resource since it requires solar energy to generate electricity. Most deployed CSP plants use parabolic troughs to collect solar energy; however, newer plants typically use the central receiver or "power tower" configuration in which all solar energy is concentrated onto a single point (instead of a line) to achieve higher temperatures. The performance characteristics of current and future plants are provided in Table B.14 below.

Table B.14 • CSP performance parameters

Parameters		Standard deployed technology	Commercially available new technology
Minimum stable load		25-30% of capacity	15%
Maximum ramp-up		10% of capacity per minute	
Maximum ramp-down		10% of capacity per minute	
Start-up time	Hot	10 minutes	
	Warm	30 minutes	
	Cold	90 minutes	60 minutes
Efficiency	At 15%	83%	
	At 33%	91%	
	At 60%	97%	
	At 80%	99%	
	At 100%	100%	
Forced outage		4%	4%
Lifetime	Years	30	
Minimum uptime	Minutes	60	
Minimum downtime	Minutes	60	
Start costs	USD_{2012}/ MW	50 per start	
Running costs	USD_{2013}/ MWh	1.1	
Fixed O&M	USD_{2016}/ kW-yr	65	

Source: Jorgenson et al. (2013), *Estimating the Performance and Economic Value of Multiple Concentrating Solar Power Technologies in a Production Cost Model*, www.nrel.gov/docs/fy14osti/58645.pdf; Jorgenson et al. (2016), "Comparing the net cost of CSP-TES to PV deployed with battery storage", https://doi.org/10.1063/1.4949183; NREL (2012), *Power Plant Cycling Costs*, www.nrel.gov/docs/fy12osti/55433.pdf.

Limitations for power plant flexibility

Although CSP is regarded as more flexible than conventional variable generation resources, such as PV and wind, one of the main limitations on the flexibility of a CSP plant is in its dependence on solar energy. Therefore, the plant's flexibility is not only defined by the parameters in Table B.14, but also by the availability of energy, whether directly from the sun or from stored solar energy. In addition, the start-up processes necessary to bring up to working temperature the solar field heat transfer fluids – synthetic oils for parabolic trough plants or molten salts for central receiver plants – may further limit the flexibility of these systems.

Options to enhance power plant flexibility

Today's parabolic trough CSP plants have a relatively long history of operation, dating back to the 1980s. As such, best operational practices have yielded annual availability exceeding 95%. Central receiver (or power tower) plants are only now seeing commercial deployment. Consequently, a high degree of uncertainty exists on the availability of these systems. Once operational experience reaches a level approaching that of parabolic trough systems, central receiver systems are expected to yield improved flexibility due to the reduced thermal inertia associated with the solar field.

Today's generation of CSP parabolic trough and central receiver plants use conventional steam-Rankine turbines to generate electricity, yielding little room for enhanced flexibility associated with the power block. Next-generation CSP systems will operate at higher temperatures, offering opportunities for integration with advanced supercritical carbon dioxide (s-CO_2) Brayton cycles. The simplicity of these cycles, combined with their much greater power density, should yield operational flexibility similar to that of today's gas-fired combustion turbines.

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