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Flexible Thermal Power Plant:
An Analysis of Operating Coal-Fired Power Plants Flexibly to Enable the High-Level Variable Renewables in Indonesia's Power System

Imprint

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Executive Summary

Despite all the scepticisms and myths, renewables will continue to grow due to their falling cost as countries around the globe are integrating more of these clean sources of energy into their power systems. A question then arises from that condition, particularly on what would be the fate of conventional fossil-based power generations that are previously dominating the generation mixture. In Indonesia, the power plants in question are coal-fired power plants (CFPPs). Just recently, the government has pledged to stop construction of new CFPPs and to retire around 5.5 GW of the existing units. By doing so, renewables can be integrated more into Indonesia's generation mixture. The retirement plan may be very well suited for ageing and inefficient units. Yet for young and just recently in operation, the plan, despite positively impacting renewables share in the generation mix, would bring financial and legal problems, especially to the state-owned utility company, PLN, which acts as a single off-taker from these power plants. Hence, as a temporary measure, the CFPPs can be operated flexibly as the middle-ground to reduce the power plants utilisation as well as reducing the losses, whilst at the same time allowing further penetration of the renewables.

This report aims to provide a holistic analysis surrounding the operation of a flexible coal-fired power plant (CFPP). Technical criteria that are typically used in determining flexible operation of a thermal power plant are provided. Each criterion is elaborated and complemented with typical range used amongst Indonesia's CFPP fleet. Technical approaches in the flexibilisation of CFPP operation as exemplified by countries, such as Germany and India, are also described. Not only that, such an operation also requires some adjustments on how the operation can be procured, deployed and later compensated. To be able to grasp the implication of such an operation, analyses on the performance and emission of selected units from different power systems in Indonesia are discussed. The analyses are further assessed in terms of the cost and benefit analyses.

Germany and India exemplify a quite distinctive approach in terms of operating their CFPP fleets flexibly. The flexibilisation in Germany can be described as heavily-weighted on technological improvements through retrofit and rejuvenation of its CFPP fleet, which are indeed costly and potentially prolonged the lifetime of its already ageing power plants. On the other hand, India has proved that the flexibilisation does not necessarily require a large sum of investment. Simply by adjusting its operational procedure, the required flexibility criteria could be achieved. This is possible, particularly on the young CFPP fleet aged at least below 10 years old. Despite the different approaches, both countries agree at least on a market design that is needed to enable flexible operation in CFPP. In the India case, this is further strengthened by compensation mechanisms for CFPP that can operate flexibly.

The analyses discussed in this report considered the operational performance, not to mention CO_2 emissions, before and after the assumed retrofit, which target improvement on the minimum load and ramp rates. Each unit is assumed to have achieved a minimum load around 30% and an increase in ramp rates by two-folds. The young unit, aged below 5 years old, is shown to have superior performance than the other units, aged between 21-25 years old, when operated flexibly. This is indicated by the change of emission relative to its pre-retrofitted condition. It is also found that the period of time a CFPP spent at its minimum does linearly impact the CO_2 emission level. In terms of cost, the flexibilisation of a CFPP causes an increase in the Levelised Cost of Electricity (LCOE) due to the investment cost needed and additional O&M cost from the cyclic operation. Nevertheless, there is a possibility to reduce, or even disregard, the investment cost, should the change required be done only on the operational procedures, as demonstrated from India's experience. Despite the increase, the LCOE is still relatively below the typical Open Cycle Gas Turbine (OCGT) and even comparable with the typical Combined Cycle Gas Turbine (CCGT), two of which are known for flexible generation, by design. Lastly, flexible CFPP does bring a number of benefits, particularly to the reduction of renewables curtailment, avoidance of costly start-up/shutdown operations and, possibly, the reduction of system cost.

Finally, this report ends with the expectation that the government will consider some of the formulated recommendations. It is important that renewables integration should be the spirit embodied in the power system planning. Indonesia CFPP fleet, which is predominantly young subcritical power plants aged below 10 years old with capacity nameplate below 300 MW, could be a temporary measure to help the transition, before then completely retired out from the system. As exemplified by Germany and India, there is a need for Indonesia to identify suitable market design and regulatory framework that enable flexible operation in CFPP. As a start, the government should put more detailed information on some indicators in the required flexible criteria and ancillary services stipulated in the Minister of MEMR regulation number 20/2020, known as the Indonesia grid code. This can be then followed by restructuring the terms in Power Purchasing Agreement (PPA) to recognise, compensate and incentivise CFPP flexible operation. A negotiation with IPP on the Take or Pay (ToP) scheme should be emphasised on lowering the 80% obligation and offer alternative avenues for IPP to gain revenues through providing capacity and ancillary services. These alternative avenues can be further supported by establishing market-based mechanisms, i.e. capacity and ancillary services markets. The markets should be operated through a bidding process and be regulated by an independent body, presumably under provision of MEMR in the form of public sector undertaking. Calculation on the compensation for providing such services could mimic the currently trialled CO_2 emissions cap and trade for CFPP fleet in Indonesia. On the technical side, the government should start identifying CFPP units for flexible operation and consider an approach that is less costly, i.e. change in operational procedure. Lastly, capacity building for operators should be held in order for them to learn from the experience of other countries in operating a CFPP flexibly. This could be in the form Focus Group Discussion (FGD), exchange form or even short courses.

1

INTRODUCTION

The Earth's climate is changing. One of the vital signs in telling the change is global surface temperature. Records show that the Earth's global surface temperature has increased 1.07 °C higher than the 1850 - 1990 period (IPCC, 2021). Figure 1 depicts a comparison of observed and simulated changes in global surface temperature from 1850 to 2020. There are two simulated changes depicted in the figure, one of them took into account both human and natural influences on the temperature change. Its comparison with the observed change reveals a staggering resemblance. Whilst a comparison with the simulated change that includes only the natural influence stands as a clear proof of human influence on deviating the course of global surface temperature change towards today's. The influence has also been found to cause the increase in the ocean acidity by around 30%, which brought fear of causing a substantial change to the chemistry of the seawater, hence disturbing the marine life and its ecosystem (IPCC, 2021; NOAA, n.d., 2020). Moreover, the intensifying extreme weather events in some regions would unlikely occur without human influences on the climate system (IPCC, 2021).

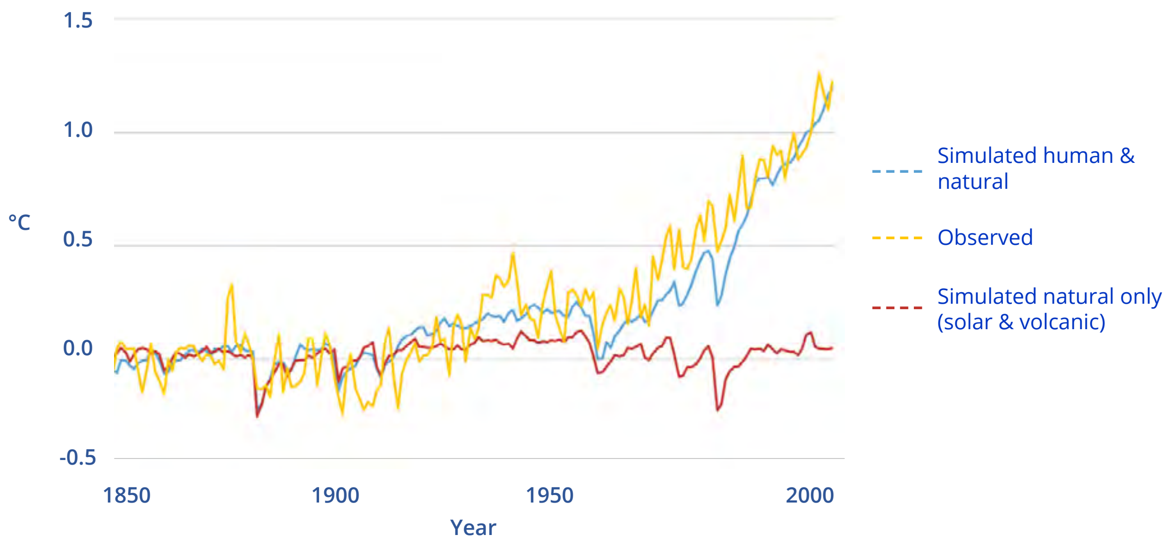


Figure 1. Comparison between observed and simulated global surface temperature change (in °C) (IPCC, 2021)

The root cause of this adversity has been solely due to the increasing concentration of Greenhouse Gas (GHG) emissions (CO_2, N_2O and CH_4) released from human activities to the atmosphere. Based on 2016 data, the energy sector, namely electricity, heat and transport, has been contributing up to 36.2 billion tonnes CO_2eq or 73.2% of human-induced GHG emissions worldwide (Ge et al., 2020; Ritchie & Roser, 2020a). Within the sector itself, the heat and electricity generations, in particular, contribute to 15.1 billion tonnes CO_2eq of GHG emissions. In terms of sources, around 63.3% of the global generated electricity comes from the burning of fossil fuels as recently measured in 2019 (Ritchie & Roser, 2020b). Amongst the fossil fuels line up, coal is clearly dominating the source of electricity generation mix, followed by natural gas, as clearly seen in Figure 2. Furthermore, coal-fired power plants (CFPPs) are responsible for one third of global CO_2 emissions. As the world is battling with the changing of the Earth's climate, it is only logical to start decarbonising the usual way of generating electricity, targeting specifically on the CFPPs on countries that are heavily reliant on the power plants, such as Indonesia.

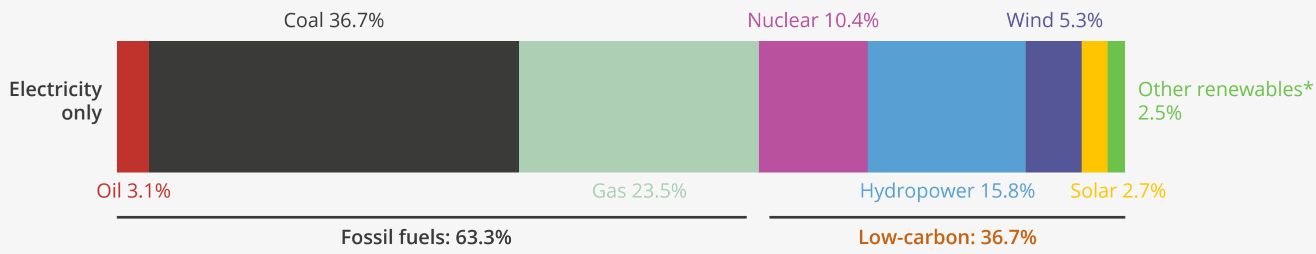


Figure 2. Electricity mix based on the sources (Ritchie & Roser, 2020b)

Indonesia has been seeing an exponential growth in its electricity consumption since the early 90s due to the country's striving economic activities. The growth however has been mainly shouldered by CFPPs deployed through several government programmes associated with accelerating electricity infrastructure development. One of these is the Fast-Track Programme (FTP), disbursed within two phases, i.e. FTP-1 and FTP-2. The abundance supply of inexpensive domestic coal has caused the generation cost of the power plants to be lower than other forms of electricity generation at the initiation of the programme. Yet, there's a catch from CFPPs cheap cost of generation. Based on 2020 data, the burning of the coal contributes to around 51% of Indonesia's total CO_2 emissions (Ritchie & Roser, 2020a). Meeting Indonesia's future electricity demand with additional CFPPs would only induce further increase in the CO_2 emissions, nudging the already-high percentage even higher. This will certainly be at odds with the orchestrated efforts globally in halting further catastrophe from the Earth's changing climate.

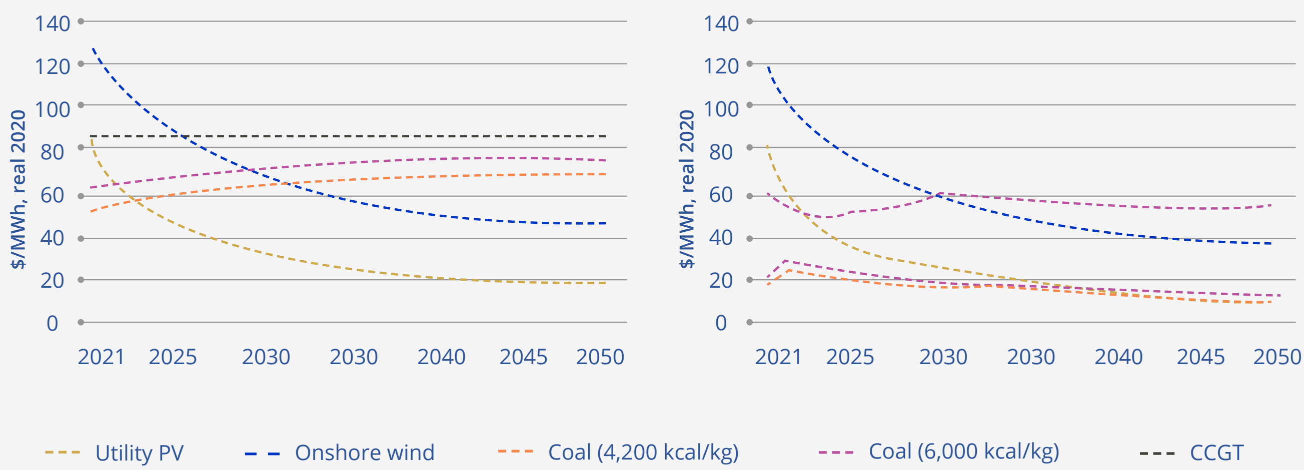


Figure 3. LCOE comparisons of utility PV (solar) and onshore wind, respectively, to new CFPP (left), and short-run marginal costs for CFPP (right) (BNEF & IESR, 2021)

Such disadvantages combined with the continuing fall of the variable renewables, namely solar and wind, cost of generation will undoubtedly cause the CFPP to lose its economic competitiveness against the emission-free alternatives. A study carried out by BNEF and IESR projected that new CFPPs will have higher Levelised Cost of Electricity (LCOE) than solar PV in 2023, mainly due to the jump in CFPPs financing costs (BNEF & IESR, 2021). Figure 3 presents the cost of generation comparisons between solar PV, wind (onshore), new CFPP, and existing CFPP. As indicated in the right-hand side figure, solar PV will eventually overtake the marginal cost of running existing CFPPs in 2040, which is estimated to be $22-25/MWh. With Indonesia's enormous solar potential, solar PV will be the next least-cost form of electricity generation in the years ahead.

The falling cost of generation for solar PV should be a call for the government to immediately plan for its massive penetration within Indonesia's power system. Aligned with this is the government plan on retiring its 9.2 GW CFPP units early. 3.7 GW out of these will be replaced by renewables. However, there hasn't been any clear indication on the replacement technology. Several CFPPs are still being constructed at the time of the writing of this paper, albeit the plan. More units are expected to be commercially up and running within the next 3 to 4 years. According to PLN's latest electricity supply business plan (RUPTL 2021-2030), there will be an additional CFPP capacity of 13.8 GW by 2030 (PLN, 2021). On paper, these additional units could be simply put to an abrupt stop and stream the unused resources, e.g. funds and technical assistance, to increasing solar PV share to meet future demand instead. However, such intervention may put the government in a conundrum as these relatively young CFPP units are yet to achieve their economic life. Then, there's the presumed risk from the lack of electricity supply as the demand grows. Hence, there should be a temporary measure that would allow solar PV, both capacity and generation, share in the system to increase and the CFPP units to be shifted from its current role to solely as capacity reserves before being gradually phased out according to the government plan. Clearly, this is a situation that necessitates flexibility in a power system, particularly in Indonesia.

Talks on power system flexibility have recently gained significant attention as renewables, particularly the variable ones, are incorporated more into the system globally. There are a number of ways of addressing flexibility in the system, depending on which element of the system is to be associated with. This could be in the form of operational flexibility, demand-side flexibility or supply-side flexibility (CPH & NREL, n.d.). To enable operational flexibility, some changes include implementing faster dispatching, expanding or coordinating across balancing areas, improving generation forecasting, monitoring ancillary service needs, adding transmission or interconnection capacity, and curtaining excess generation. The demand-side flexibility is achieved through improving energy efficiency, implementing sector coupling, upgrading distribution infrastructure, and adding energy storage. Lastly, improvements required to flexibly the supply-side include boosting flexibility of existing generators and adding new generators or retiring old and inefficient ones.

Countries, such as Germany and India, have actually initiated the flexibilisation on the supply-side of their power systems. Germany has been the first to implement such mode of operation in its ageing CFPP units, of course, after having previously rejuvenated or retrofitted. In India, particularly, the supply-side flexibility has been trialled on several of its CFPP units, e.g. Dadri and Mouda. These countries have foreseen the flexibilisation of their CFPP units as a way to recognise the urgency of energy transition by viewing the existing units not as barriers for the transition. Instead, these units would actually serve as a medium that facilitates the integration of higher renewables, particularly the variable ones.

Germany has proven the success in keeping grid stability using this approach, reducing renewable curtailment while simultaneously increasing the penetration of variable renewable into its generation mix. Driven by the urgency of utilising Indonesian renewable, particularly solar, potential that acts as a foundation, the flexibilisation of the country's CFPPs unit must then be considered. Practices of flexible CFPP operation exemplified from Germany and India could act as a learning platform. Not only the plant-level operational changes, these countries have shown that the flexibilisation also required changes in how the electricity is procured, i.e. market design, as well as the development supporting regulatory frameworks, e.g. compensation mechanism for CFPP operator for its cyclic operation. Therefore, the final question for Indonesia is not on whether existing CFPP units should or should not be operated flexibly, but rather on when and where these units flexibilisation can be carried out, hence increasing solar PV share in the Indonesia capacity and generation mixes.

2

INDONESIA CLIMATE POLICY AND ENERGY PLANNING

2.1. Indonesia National Determined Contribution (NDC)

Indonesia submitted its first NDC to the United Nations Framework Convention on Climate Change (UNFCCC) in 2016. In it, Indonesia pledged to cut its emissions down by 29% (unconditional) up to 41% (conditional) in 2030[1]. In 2021, the government submitted the updated NDC prior to COP26. Furthermore, the appointed ministry, Ministry of Environment and Forestry (MoEF), also produced the LTS-LCCR 2050[2] as mandated by Article 4.19 of the Paris Agreement. The document, which has drawn appreciation, mainly serves as a guide to develop and implement the country's updated NDC. It will oversee the harmonisation of efforts to tackle the climate crises, whilst at the same time promoting economic growth and just, as well as inclusive, transition. In addition, the updated NDC was applauded for the inclusion of gender equality and decent work and Indonesia's commitment to the International Convention on Adaptation. Nevertheless, it has been criticised for being too lean, in terms of ambition, in the country's efforts and commitments to tackle the climate crises, as well as reducing its emissions, especially on the Forestry and Other Land Uses (FOLU) and energy sectors (Jati, 2021).

Being the second largest GHG emitter, the energy sector is enlisted in Indonesia NDC, alongside the FOLU, with a higher emission reduction target relative to the Business As Usual (BAU) scenario than other sectors, such as waste, IPPU (Industrial Process and Produce Use) and agriculture. Within the updated NDC, the reduction target for the sector under the most optimistic scenario, i.e. conditional, has increased from previously 398[3] to 446 MTon CO_2eq. With the latest amount of abatement, the GHG emission level is projected to be at 1,223 MTon CO_2eq by 2030 (Republic of Indonesia, 2021). The LTS-LCCR 2050 projects an even lower emission level, estimated to be at 1,030 MTon CO_2eq (MoEF, 2021). Despite these acclaimed reductions, the emission levels are deemed too high to be in line with the 1.5°C Paris Agreement target. Sure enough, as indicated in the LTS-LCCR 2050, the emission level will still remain at 572 MTon CO_2eq by 2050. To be in line with the target, the GHG emission level must instead get to 562 MTon CO_2eq by 2030 before hitting zero emission level by 2050 (IESR et al., 2021).

The mitigations in reducing the GHG emission level in the energy sector assumed in the updated NDC are spread across different sub sectors, namely power generation, transportation and energy use in industry and building. Amongst these sub-sectors, the power generation dominates the yearly energy sector GHG emissions, followed by the transportation and industry sectors. Ideally, the updated NDC should have assumed the massive use of low-carbon technologies, such as solar PV and wind, for the power generation sub-sector during the emission reduction projection exercise. Instead, what the updated NDC had actually assumed was far from ideal. By 2030, the power generation still saw the implementation of clean coal technology and the renewable's electricity production was limited to 133 TWh, an equivalent to 22 GW in terms of capacity (Republic of Indonesia, 2021). The lack of ambitious climate mitigation targets in the updated NDC has a follow up consequence in the formulation of Indonesia National Energy Plan, widely known as RUEN, that does not reflect the urgency of energy transition in mitigating the Earth's changing climate.

[1] The difference between unconditional and conditional terms is in the absence of international aid. The 41% NDC is achievable provided that international aid is available.
[2] The document was submitted along with the update NDC.
[3] This is the target in the first NDC submitted in November 2016.

2.2. RUEN, Indonesia National Energy Plan

In 2017, the government of Indonesia released its national energy plan, known as Rencana Umum Energi Nasional (RUEN) (Rencana Umum Energi Nasional, 2017). The document, which is a strategic implementation of Kebijakan Energi Nasional (KEN) PP No. 79/2014, has been providing guidelines for the government at national and regional levels to achieve energy independence and security to support the country's development. The document highly emphasises the direction of future energy usage, from solely being exported commodities to capital for the development of the nation. Due to its prominent stature, RUEN has been referred in deriving sector-specific energy and electricity plans, such as electricity supply business plan, known as Rencana Umum Penyediaan Tenaga Listrik (RUPTL), produced by the PLN and national electricity plan, known as Rencana Umum Ketenagalistrikan Nasional (RUKN), issued by the Ministry of Energy and Mineral Resources (MEMR).

The planning considered in RUEN spans from 2015 to 2050. With all the assumptions made in 2015, the modelling in RUEN shows that cross-sectoral fossil fuels usage is still dominating Indonesia's primary energy supply. By 2025 renewables will make up to 23% of the energy mix, followed by oil at 25%, natural gas at 22% and coal at 30%. The power generation sub-sector will have the renewables generation capacity portion up to 33.3%, whilst the fossil-based generations cover the remaining ~67%. Further outlook in 2050 reveals that the renewables will only increase by 8% to 31%. Reduction is observed for the oil and coal, each down to 19.5% and 25.3%, respectively. The natural gas, however, increases by 2% to 24%. In 2050, renewables will only increase by ~5% to 37.8% in their contribution to the national generation capacity. The fossil-based ones, sure enough, will decrease by ~5% to 62.2%. Yet, they are still dominating the generation capacity mix.

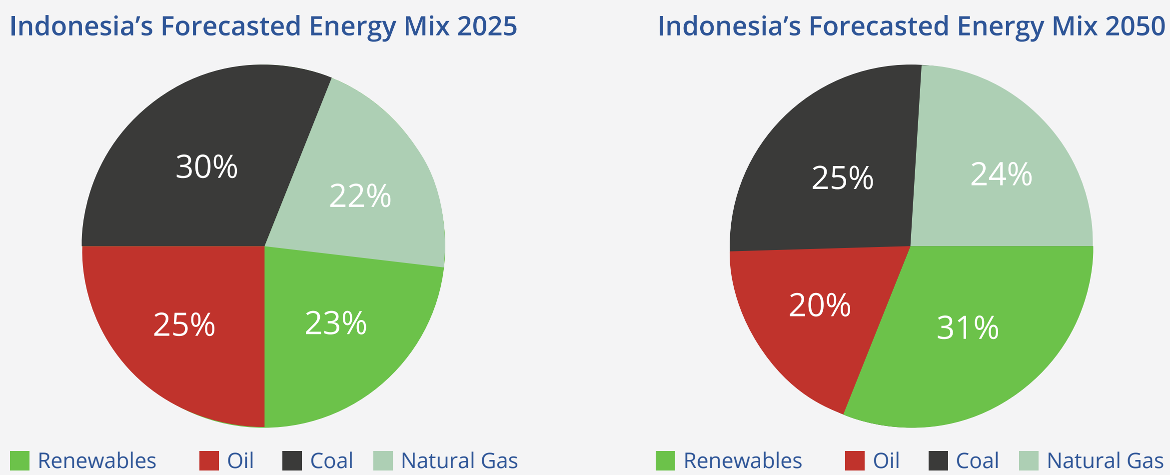


Figure 4. Indonesia's projected primary energy supply in 2025 and 2050 (Rencana Umum Energi Nasional, 2017)

Sustained fossil fuels dependence in the country's primary energy supply consequently results in the increase of GHG emission level. In 2025, it is estimated that the GHG emission level will hit 893 MTon CO_2eq. It then increases to ~1,950 MTon CO_2eq by 2050. Power generation sub-sector stands the largest source of emissions, followed by industry, transportation, residential and commercial sub-sectors. Nevertheless, the RUEN's modelling emission trend is indeed lower than the Business as Usual (BAU) scenario presented in the plan. In 2025, the reduction is rated at 35% and by 2030 it reaches 41%. At the end of the considered timespan, the reduction hits 58%. These planned reductions are acclaimed to be in line with Indonesia's updated NDC. Yet, as mentioned earlier, the NDC itself is still deemed too far from being an ambitious national target, let alone to meet the 1.5°C Paris Agreement target.

2.3. Global Coal to Clean Power

During the last UN Climate Change Conference 2021 in Glasgow, a statement pledging to a global transition from coal to clean power was jointly undersigned by over 40 countries and subnational representatives, as well as a number of company's CEOs (UNCC, 2021). There are four clauses committed by the statement signees to get the transition on the move, namely:

- Rapid scale-up of clean power generation and energy efficiency deployment
- Rapid scale-up of technologies and policies to shift away from unabated coal power generation[4] by 2030s for major economies and by 2040s globally
- Ceasing issuance of new permits for new unabated CFPP projects[5], ceasing new construction of unabated CFPP projects and ending new direct government support for unabated international CFPP
- Strengthening domestic and international efforts in the preparation of a just and inclusive transition framework for affected workers, sectors and communities as the result from shifting away from unabated coal power

Indonesia is amongst the signees, despite not endorsing the third clause of the statement. Nevertheless, as part of its commitment to reach net zero by 2060, Indonesia is still considering accelerating coal phase out by 2040s. These timelines are conditional and could potentially be sooner provided that international assistance, financially and technically, is available.

2.4. Key Takeaways

It is quite unfortunate that these important policy documents do not really address the urgency of climate change, albeit partially committing to the Global Coal to Clear Power Transition statement. Both the NDC and RUEN documents need to be further updated in order to be able to catch up with changing trends that are in favour of renewables. The economy of scale from renewables has been displayed in many electric generation procurement around the globe, causing the continuous fall of the electric generation.

Despite the lack of ambitious targets and plans within the documents, the government has actually developed a supporting regulatory framework to encourage the increase of renewable share in the energy mix, an initiative worthy of appreciation. With the latest revision of the Minister of Energy Regulation regarding Commercial Solar PV Rooftop, MEMR Regulation 26/2021, of course, it will be a cornerstone for the substantial growth of Indonesia's renewable energy for the upcoming years. With the growing share of renewables, the grid is required to be less rigid than it used to due to the intermittency nature of the renewables, particularly the variable ones. Due to its current dominance in the generation mix, the fossil-based generations could actually play a role in the energy transition by transforming themselves into a load-follower power plant. In other words, these power plants, especially the CFPPs, will have to operate flexibly.

[4] Unabated coal power generation refers to the application of CFPP without mitigation measures to reduce CO_2 emissions, e.g. Carbon Capture Utilisation and Storage (CCUS)
[5] These are projects that have not yet reached financial close

3

FACTORS DETERMINING THE FLEXIBLE OPERATION IN A THERMAL POWER PLANT

Initially, a CFPP is designed to provide constant and stable load[6] to the grid, hence suitable for a base load generation. Part of its stability comes from the working principle of the power plant itself, which is based on the Rankine cycle. It is a closed loop system involving a working fluid, in this case water, that undergoes different changes in its state, i.e. liquid and steam. The change from liquid to steam happens in a boiler, where coal and air mixture is combusted, generating flame with high heat intensity. The heat is then transferred to the water through a heat exchanger, turning the water into steam. Both the combustion and heat transfer processes require some amount of time, limiting the ability of the power plant to be operated cyclically. Being in a state of high pressure and temperature, the steam thus contains a high level of energy, by which the energy is extracted through an expansion process, rotating steam turbines that are coupled to a generator, producing electricity. The expanded steam with low pressure and temperature then flows to the condenser to be cooled down, turning it back to water. Figure 5 illustrates the explained process in a simple manner.

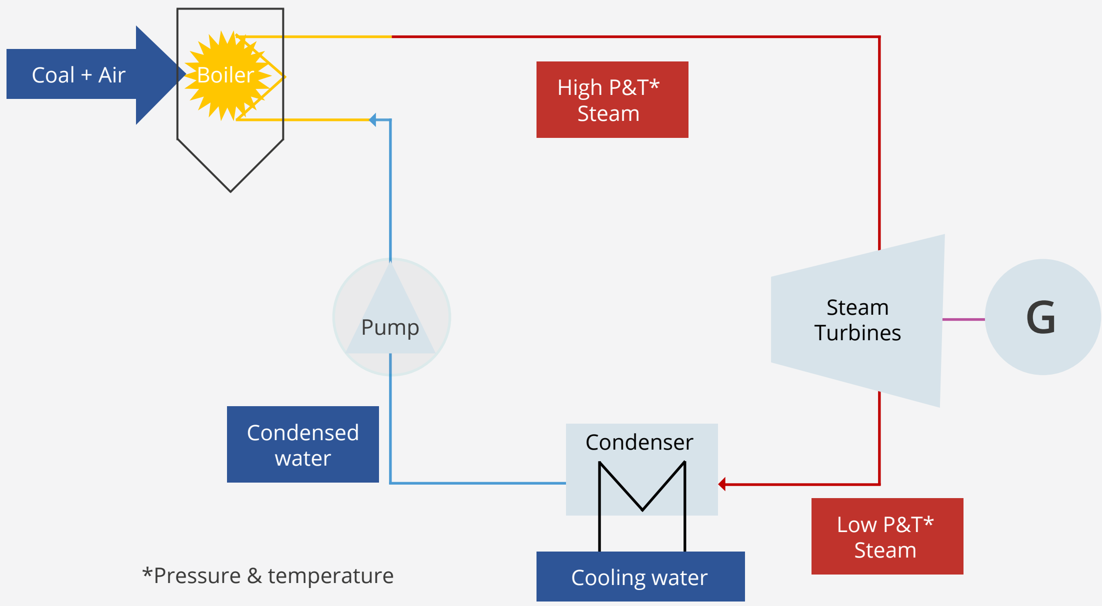


Figure 5. Simple illustration of a CFPP working principle

To be able to operate flexibly, some changes are needed. These changes are exemplified in countries that are already or planning to operate their CFPP fleet flexibly. Prior to that, however, it is important to understand the yardsticks of flexible operation in a power plant. Hentschel et al. (Hentschel et al., 2016) listed three factors determining the flexibility of a power plant; these are minimum load, load change rates or ramp rates, and start-up time (and/or costs).

[6] Electricity demand fluctuates from day to day. It may reach a peaking point during the period of high demand. However, when it drops, it never goes across a certain load threshold. The threshold is better known as base load.

3.1. Minimum Load

One of the factors that determine an operational flexibility is minimum load operation. The term can be defined as the lowest safe and reliable operating point, generally in % of nominal load (Pnom), that can be performed without auxiliary firing. The term also means compliance with applicable environmental regulations. With the latter scoping, the minimum turndown is sometimes regarded as minimum environmental load (MEL), with particular use in a gas turbine (Abudu et al., 2020).

When it is set at the lowest level, the minimum load would promote at least three benefits, as suggested by Bistline (J. E. Bistline, 2019):

- Mitigating short-run costs of startup and shutdown, hence minimising financial losses
- Enabling a unit to respond to quick residual load[7] changes, providing grid services, and receiving revenues in ancillary service markets
- Reducing long-run costs from cycling-induced wear-and-tear, e.g. fatigue damage, due to frequent startup and shutdown

Despite these value prospects from the minimum load, it should be noted that further assessments against higher heat rates, emissions, and marginal production cost have to be taken into consideration. Globally, the average CFPPs, both with hard coal and lignite, minimum load stands at a range between 25-60% (IRENA, 2019). The lowest end comes from the hard coal-based CFPPs. Table 1 presents CFPP minimum load according to the state-of-the-art, average use and post-retrofit in typical hard coal and lignite-fired power plants.

CFPP (based on fuel type)	Minimum Load		
	Stage-of-the-art[8]	Average use[9]	Post-retrofit[10]
Hard coal/Anthracite	25-40%	25-40%	10-20%
Lignite	35-50%	50-60%	10-40%

Table 1. CFPP minimum load of hard coal and lignite-fired power plants

Specifically for Indonesia, its CFPP units are fired up using either lignite, sub-bituminous, bituminous or even a blend between these coal-types. Suralaya, for instance, consumes the sub-bituminous for its power generation (Suprapto, 2009). The power plant consists of 8 units with a total generating capacity of 4,025 MW, placing the power plant as one of the largest in the country. As indicated in one published literature, the unit 1-7 have a range of average use minimum load range between 67.5-80% (Murti et al., 2020). The higher end of the range comes from the power plant's unit 1-4 due to these units' age that are already over 33 years old. Another sub-bituminous-fired power plant unit, 710 MW Tanjung Jati B unit 2, has the average use minimum load at 59% (Bono & Wahyono, 2017). Some power plants are also run on blended coal-types between high coal rank (e.g. anthracite and bituminous), medium coal rank (e.g. sub-bituminous) and low coal rank (e.g. lignite), namely Indramayu and Pacitan. Such an approach is intended to cut down the power plant cost of generation due to lignite being the cheapest amongst other coal ranks (Suprapto, 2009; Wibowo & Windarta, 2020). The blending with higher coal rank comes with an expectation to improve the quality of the fuel for the power plants. The 3x330 MW Indramayu power plant, for instance, runs on a blended fuel between sub-bituminous and lignite. The power plant average use minimum load is rated at 53% (Dhamayanthie & Desasi, 2019). Similar blending approach is also applied in the 300 MW Pacitan power plant that has the average use minimum load at 55% (Rasgianti et al., 2021).

[7] A parameter obtained from subtracting the renewables hourly generation from hourly electricity demand
[8] Source: (Agora Energiewiende, 2017)
[9] Sources: (Agora Energiewiende, 2017; IRENA, 2019)
[10] Source: (Henderson, 2014)

3.2. Ramp Rate

Ramp rate determines the power plant's ability to adjust its net load, ΔPnet, over a span of time, Δt. The ramp rate is generally expressed in unit load, either MW or % of Pnom, per minute, i.e. MW/min or %/min. It is considered as an important factor as a large share of the renewables would result in larger load variations in the residual load than variations in the demand. In practice, the ramp rate would determine how fast a power plant can reach its maximum output from its initial operating point, for instance at minimum turndown load. Today's average CFPPs ramp rate stands at a range of 1% - 4% (IRENA, 2019), with the lowest end coming from the lignite-based CFPPs. More details are presented in Table 2. As indicated in the public domain literature, the Indonesian CFPPs are indicated at the lowest end of the aforementioned range. Suralaya, Tanjung Jati, and Paiton power plants, all of which run on sub-bituminous coal-type, have an average use ramp rate at 1%/min (Fathurrodli, 2014).

CFPP (based on fuel type)	Ramp Rate		
	Stage-of-the-art[11]	Average use[12]	Post-retrofit[13]
Hardcoal/Anthracite	3-6%	1.5-4%	3-6%
Lignite	2-6%	1-2%	2-6%

Table 2. CFPP ramp rate of hard coal and lignite-fired power plants

3.3. Start-up Time

There are times that necessitate temporary shutting down of a power plant, usually when a situation is deemed economically beneficial. At times where the power plant's generation is later required in the system, start-up time is a crucial factor that determines the flexibility of the CFPPs. The start-up time can be defined as the period from starting the plant firing operation until reaching minimum load (Agora Energiewiende, 2017). Depending on the period of out of operation, there are three types of start-up time, according to Gostling (Gostling, 2002):

- Hot start-up time: out of operation for 8 hours
- Warm start-up time: out of operation between 8 and 48 hours
- Cold start-up time: out of operation for more than 48 hours

Table 3 presents typical start-up time for hard coal and lignite-fired power plants. For the hot start-up time, today's average CFPPs requires a period of 2.5 to 6 hours. The fastest hot start-up time is usually observed at hard coal-based power plants. The cold start-up time, on the other hand, ranges between 5 - 10 hours, with the hard coal-based power plants being the fastest. The accolade of the hard coal in the start-up time is mainly due to its larger energy density, ranges between 25-35 MJ/kg, and lower water content than the lignite (Agora Energiewiende, 2017). These features are, therefore, making the coal preparation process to be relatively faster than in the lignite-fired power plant. Indonesian CFPPs start-up time is generally within the ranges indicated in Table 3.

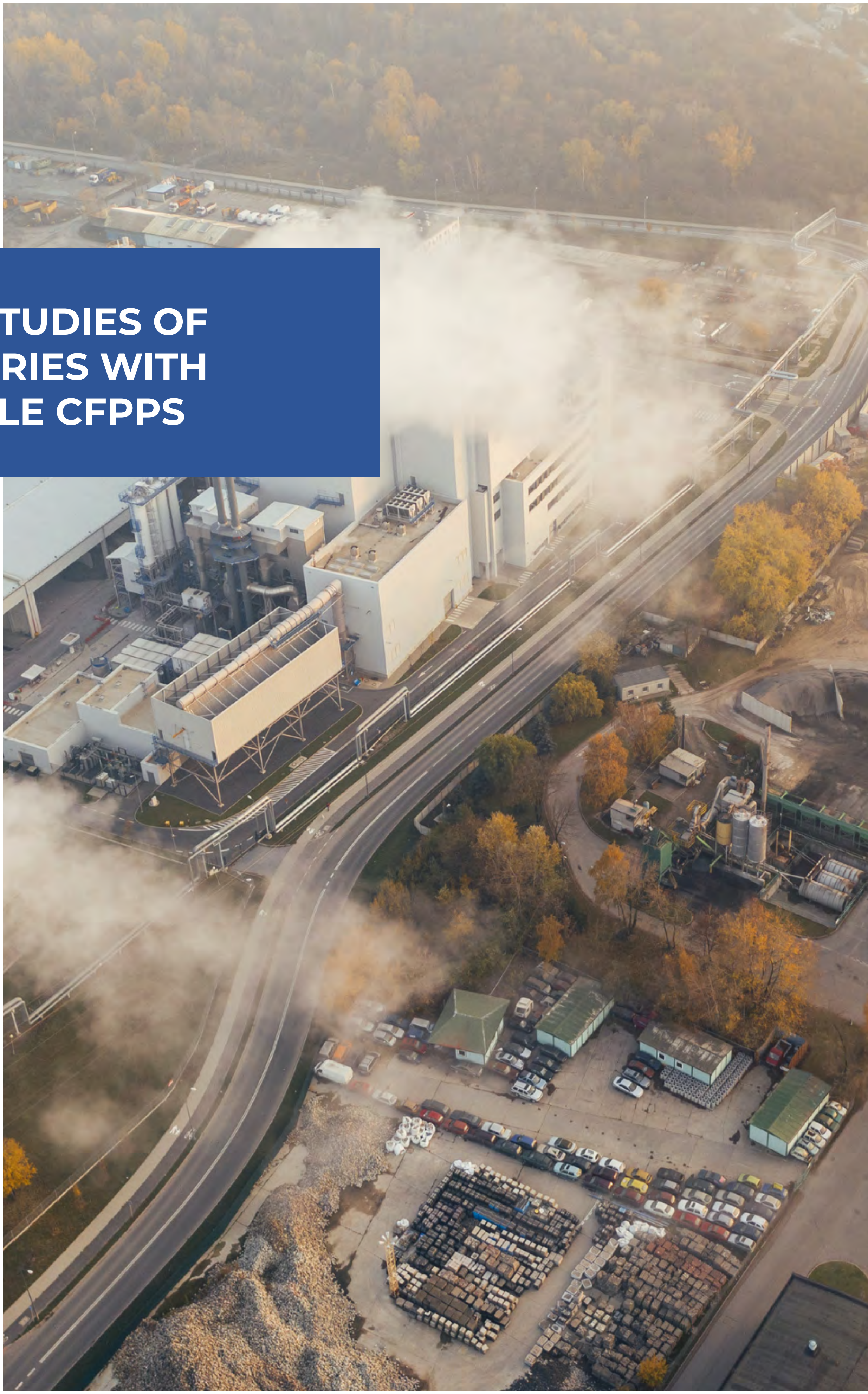
CFPP (based on fuel type)	Start-up Time (The Range Covers Both Hot and Cold Start-up Times)		
	Stage-of-the-art[14]	Average use[15]	Post-retrofit[16]
Hard coal/Anthracite	80 mins-6 hours	2-10 hours	80 mins-6 hours
Lignite	85 mins-8 hours	4-10 hours	75 mins-8 hours

Table 3. CFPP start-up time of hard coal and lignite-fired power plants

[11] Source: (Agora Energiewiende, 2017)
[12] Source: (Agora Energiewiende, 2017)
[13] Sources: (Agora Energiewiende, 2017; Feldmuller, 2017)
[14] Source: (Agora Energiewiende, 2017)
[15] Source: (Agora Energiewiende, 2017)
[16] Sources: (Agora Energiewiende, 2017; Feldmuller, 2017)

4

CASE STUDIES OF COUNTRIES WITH FLEXIBLE CFPPS



Current state and future growth of the REs have been largely optimistic. Hydropower still occupies a lion share of installed capacity within the global renewable energy mix at 1,332 GW in 2020 (IRENA, 2021). Within the same year, the global installed capacity of solar PV and wind energy, however, is actually catching up with a remarkable growth, each with additional installations of 127 GW and 111 GW, respectively. Hence, as per 2021, the installed capacity of these energies has reached 713 GW and 733 GW respectively. Under IRENA's moderate scenario, the generation capacity of these variable REs (VREs) is expected to rise from, respectively, 582 GW and 624 GW in 2019 to 2037 GW and 1455 GW in 2030 (IRENA, 2020).

Unlike the hydropower and geothermal, the VREs' outputs, as the name implies, are variable and by virtue of nature. Meaning, VRE-based power plants produce electricity when the wind blows or the sun shines. These kinds of power plants are also insensitive to changes in demand for electricity (Agora Energiewiende, 2017). This is in contrast to the CFPPs which can be essentially characterised by their base load capacity. The design of these power plants suited the electricity demand pattern of relatively low variability. Hence, these power plants can run at, or close to, their maximum capacity for more than 80% of the year, in the absence of VREs (Agora Energiewiende, 2017). However, in a power system where the VREs are taking over a large share of its electricity generation, the CFPPs are prevented from running at their base load capacity and must be run with much greater flexibility. In doing so, the curtailment of VREs, which could lead to the increase in the cost of generation, can then be avoided. Having said that, there will clearly be a role readjustment of the CFPPs, from previously being a prime electric generator to solely a dispatchable backup.

Germany and India are countries with quite a high share of VREs within their power systems. In Germany, wind and solar account for a total of 63.83 GW and 55.3 GW, respectively. The case is the same for India, with 39.25 GW for wind and 40.1 GW for solar power. The change in the generation mix due to high VRE penetration over the years has led both countries to pursue the flexibility of coal-fired power plants as a way to maintain grid stability. Germany, being the global cornerstone and leading example of flexible operation of a coal-fired power plant, while India is relatively new but serious about shifting the operating nature of its CFPP fleet into a flexible one. Despite the difference, both case studies showcased below should serve their purposes as a bridge that connects best practices from the early to the latest phase of the flexibility of CFPPs operation.

4.1. Lessons Learned from Flexible CFPPs in Germany and India

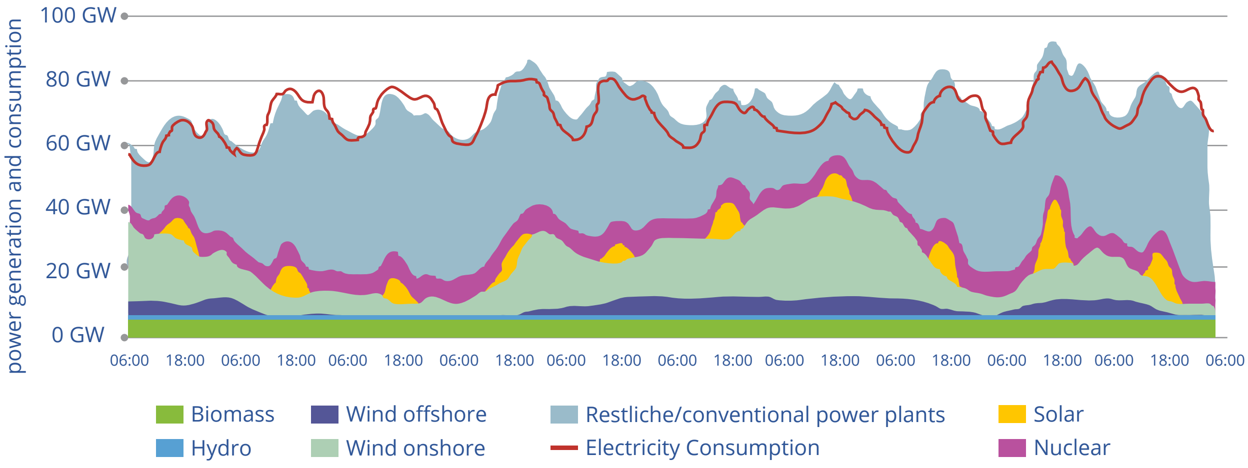
4.1.1. Germany

Recent Electricity Supply and Demand Profiles

In 2021, 17.98% of Germany's installed capacity came from CFPP, consisting of hard coal and lignite (Fraunhofer ISES, n.d.). During the same year, renewables contributed to a staggering 61.96% of the installed capacity mix with 55.49% out of this figure coming from VREs, namely offshore wind, onshore wind and solar. Having dominated by the VREs, Germany has on average 31% of its power demand fulfilled by the VREs within the first 10 days of November 2021, as shown in Figure 5. Lowest VREs generation mix is observed on 3 November, contributing only at 11% in the generation. Almost half of the generation, ~42.5%, was generated by CFPP. However, the situation flipped around on 7 November with the VREs dominating the generation mix at 59%. In response, the CFPP generation share was reduced to 15%.

As observed from the figure, the electricity consumption in Germany is relatively stable. The high feed-in from the VREs can be observed in the early hours of 1st, 5th, 6th and 7th November. Within the last two dates, the VREs continuously supplied the grid, with the generation mix of more than 40% on each date. The conventional power plants, as can be seen in the lower profile of Figure 5, immediately reacted to the power surge from the

VREs by adjusting their output within the same time window. As the VREs generation significantly falls in the following days, the conventional power plants ramp up their output to meet the demand, which is rapidly increasing on 8th November. The conventional power plants continued to supply the grid until 10 November. As clearly observed from the figure, these power plants, including the CFPP, are already operating flexibly in correspondence to the generation of renewables.



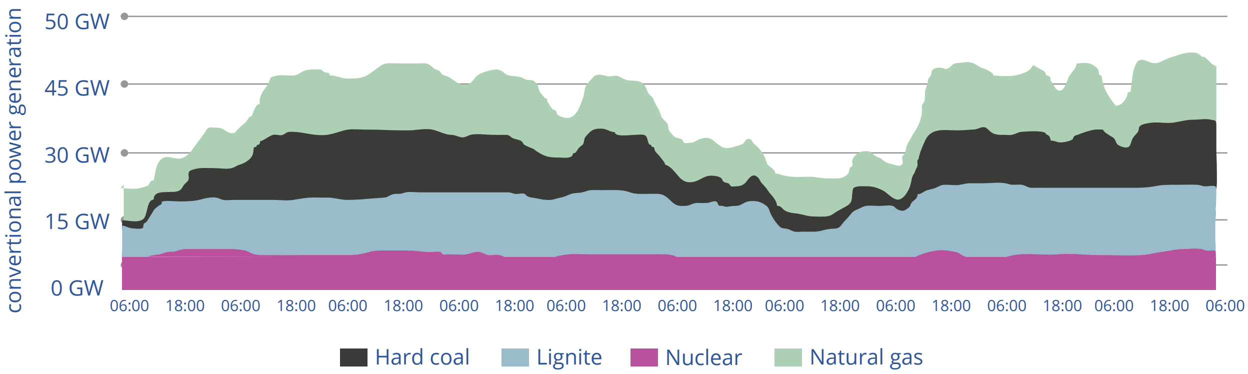


Figure 5. Upper power generation of all power plants (including the renewables) and consumption profiles in Germany during 10 days in November 2021; **Lower** breakdown on the conventional power plants generation within the same period of time (Agora Energiewiende, n.d.)

Germany Flexible Operation Recipes at Different CFPPs

As reflected in Figure 5, operational flexibility is apparently quite mature in Germany's conventional power plants, particularly the CFPPs. Within subsequent passages, practical examples of different retrofitting options for flexible CFPPs in Germany are presented. The examples showcase a number of Germany power plants that have been in operation for more than 25 years. Hence, the majority of the retrofitting options are either a package of plant modernisation, replacement and/or upgrade of existing subsystems, or a feedwater repowering using other forms of generation (e.g. gas turbines). Each option may improve all or some flexibility criteria mentioned in the previous section. The plant modernisation, for instance, has in fact reduced the power plant's minimum load and start-up time by 39% and 1 hour, respectively, and increased the ramp-rate by 243%. Another option, such as the upgrade of existing subsystems, addressed a different set of flexibility criteria. In one power plant, the option has successfully reduced the minimum load by 28%. There are, however, examples of operational change to make a power plant flexible. By operating with a single mill burner, a power plant has managed to reduce its minimum load by 64%.

Neurath Block E - The country has been working on flexing CFPP operation when it first did a retrofit work on 600 MW Neurath Block E subcritical coal-fired power plant in 2011 (Von Markus, 2011). A total of €70 million was invested in retrofitting the power plant. The power plant itself was already 35 years old at the time of the retrofitting work in 2011, extending the power plant lifetime to another 10 years. The power plant control technology was renewed to the latest one. In addition, some of the power plant subsystems were also rejuvenated with the construction of a new steam cycle, including an addition of a new condenser and upgraded cooling tower. As a result of this 2.5 months work, the efficiency of the power plant increased by 0.6%, which translated to 100,000 tonnes/year of CO_2 reduction. In terms of its flexibility, the minimum load was reduced to 42.9% from 69.8%, ramp rates were increased to 2.38%/min from 0.7%/min, and start-up time was shortened to just 3 hours 15 mins from 4 hours 15 mins.

Weisweiler Unit G and H - Another form of retrofitting to make a CFPP flexible is through feedwater repowering. Figure 6 illustrates the repowering cycle integration with the CFPP water-steam cycle. It involves a gas turbine being placed upstream of the water-steam cycle within the CFPP. Heat from the gas turbine exhaust warms the feedwater via a heat exchanger or recovery preheater as indicated in the figure. Whilst this happens, the gas turbine, at the same time, can provide power to the grid served by the CFPP through its own generator, marked as 'G' in the repowering cycle presented on the figure. This, in turn, reduces the CFPP start-up time, as well as increases the CFPP ramp rates. In the case of Weisweiler Unit G and H, the gas turbines are only in operation during the period of peak demand and the electricity prices are favourable (RWE, n.d.).

The retrofit was carried out at unit G & H of Weisweiler subcritical power plant in 2006 and 2007, respectively, and resumed operation in 2007 and 2008 (Agora Energiewiende, 2017; RWE, n.d.). These units have been in operation for 32 years at the time of the retrofitting and have a generating capacity of 600 MW for each unit. Two gas turbines with 190 MW of net power each were installed in each unit. Pre-heating the feed water with gas turbine exhaust increased the net power of the CFPP by 80 MW (+6.6% of nominal load). The operator also claimed an increase in the overall efficiency and reduction in the CO_2 emission by ~11% (RWE, n.d.; Umwelt Bundesamt, n.d.). In terms of investment, the gas turbines and their auxiliary components for the integration cost around €150 million.

The very same power plant has another example of making the CFPP flexible, this time, through improving the control system (Agora Energiewiende, 2017). Digital control system was implanted in the power plant. This enabled reduction of the minimum load by 170 MW in unit G by 110 MW in unit H. Not only that, the retrofit, along with upgrades in the plant engineering, has also contributed to the increase in the ramp rates, particularly in unit G, by 10 MW/min or 1.67%/min. The approximate cost of the retrofit ranged from €60 to €65 millions.

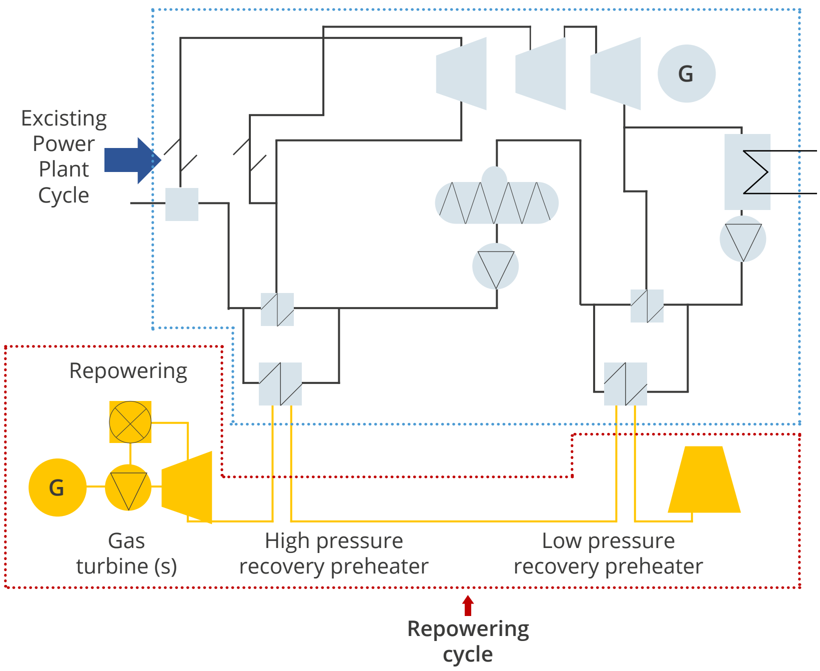


Figure 6. Diagram of repowering cycle in CFPP (Agora Energiewiende, 2017)

Zolling Unit 5 - Operation optimization is also an option to make a CFFP flexible. One example of this is the implementation of the BoilerMax control system by ABB, which was integrated into 450 MW unit 5 Zolling supercritical coal-fired power plant and was utilised for the online optimization of the power plant start-ups. Such a control system uses dynamic optimization, which beats the performance of conventional one that, by default, complies with design limits. BoilerMax, on the other hand, was developed to allow exploitation of the design limits (ABB Group, 2014). The principle mechanism of the control system is illustrated in Figure 7.

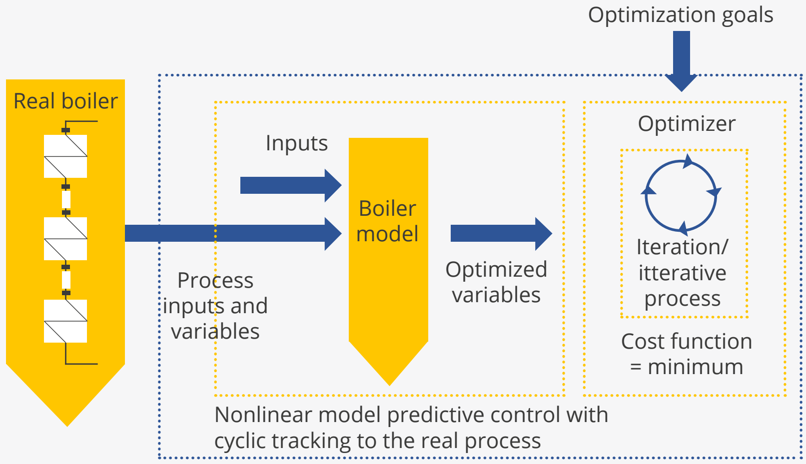


Figure 7. Principle mechanism of BoilerMax (ABB Group, 2014)

One of the key features of BoilerMax is the ability to shorten start-up time. The start-up time is shortened by 33%, as can be seen in Figure 8. The reduction resulted in an 11% decrease in the start-up cost since demand for auxiliary power, i.e. light oil and electrical auxiliary power, is lower (Ruediger & Weidmann, 2007). The CFPP also received a new steam turbine, which would see an increase in the efficiency by 1%, from ~41% to 42.3% (Merkur, 2011). The output, as a follow up, also increased by 12 MW. The increase in the efficiency has resulted in the reduction in CO_2 emission by ~12% (Umwelt Bundesamt, n.d.). The process control system of the power plant was also replaced with ABB's 800xA that worked well along with BoilerMax. The new process control system itself cost around €2.5 million (INP, n.d.). In total, all these retrofittings in unit 5 Zolling power plant cost around €80 million, with a completion time of 3 months. The power plant itself was 25 years old, when the improvement works took place in 2011.

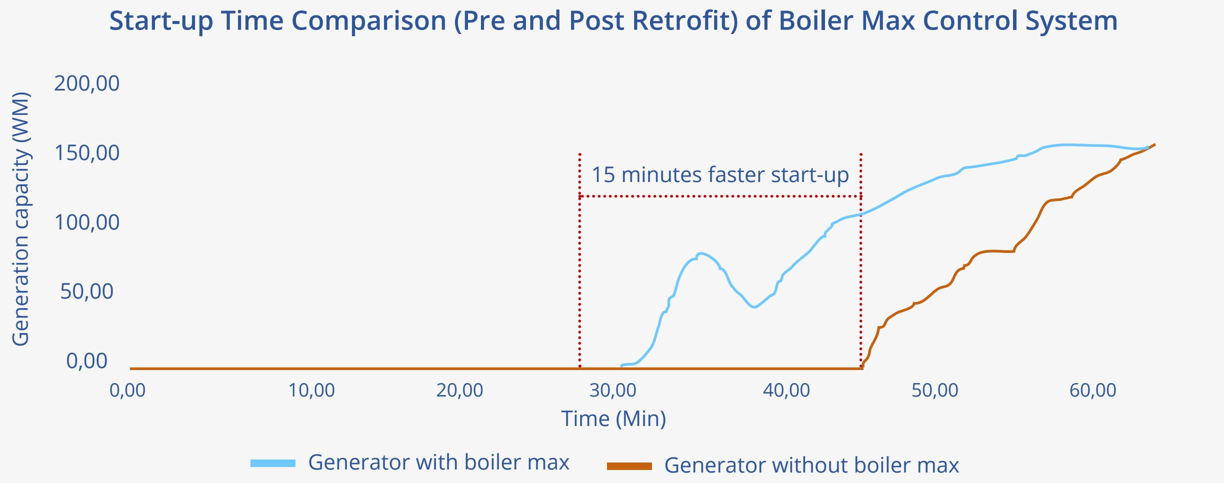


Figure 8. Improvement in the start-up time using BoilerMax (Agora Energiewiende, 2017)

Bexbach - The subcritical coal-fired power plant has a generating capacity of 721 MW and was built in 1983. With a single mill operation[17], the power plant operator was able to reduce the power plant's minimum load to 90 MW from 250 MW. The former minimum load was carried out with two mills in operation. Heinzel et al. (Heinzel et al., 2012) found out that the flame during the single mill operation is even more stable than the two mills in a trial run in May 2011. In the single mill operation, the burner and the mill are allowed to operate close to their design point, hence the flame stability. In support of this operation, additional flame controllers were added to the boiler to improve flame monitoring. Despite the flame stability, the operation, however, is constrained by the water-steam cycle, particularly in maintaining its appropriate pressure level (Agora Energiewiende, 2017). Figure 9 presents the operational parameters to attain the new low load in Bexbach power plant. Since September 2011, the power plant low load operation has been commercially and frequently requested, resulting in a daily load profile as presented in Figure 10.

Heilbronn Unit 7 - The same single mill operation in Bexbach power plant was also tried at the 800 MW coal-fired power plant in May 2011. Heilbronn unit 7 was operating commercially in 1985. Prior to the trial, the minimum load was previously rated at 200 MW, achieved by operating the boiler with two mills. With the single operation, the power plant could be operated until 100 MW. During the trial, the flame intensity was also measured to see whether such an operation affected its stability. The result is presented in Figure 11.

Apart from the success in running with single mill, the power plant also received a modernization package for its steam turbine stages in 2009 (Stamatelopoulos, 2011). New blade technology, at that time, was installed in the power plant's high pressure (HP), intermediate pressure (IP), and low pressure (LP) steam turbines. In addition, the inner casings, shafts and sealing system were rejuvenated and replaced. As a result, the power plant saw an increase in its efficiency by 1.1%, which translates to a 2.8% reduction in CO_2 emissions, giving the new figure at 830 gr CO_2/kWh.

[17] Coal Mills are used to pulverize and dry coal before it is blown into the power plant furnace. At a certain net power output, it is feasible to shut down some of the mills and have the remaining mills operate closer to their design point.

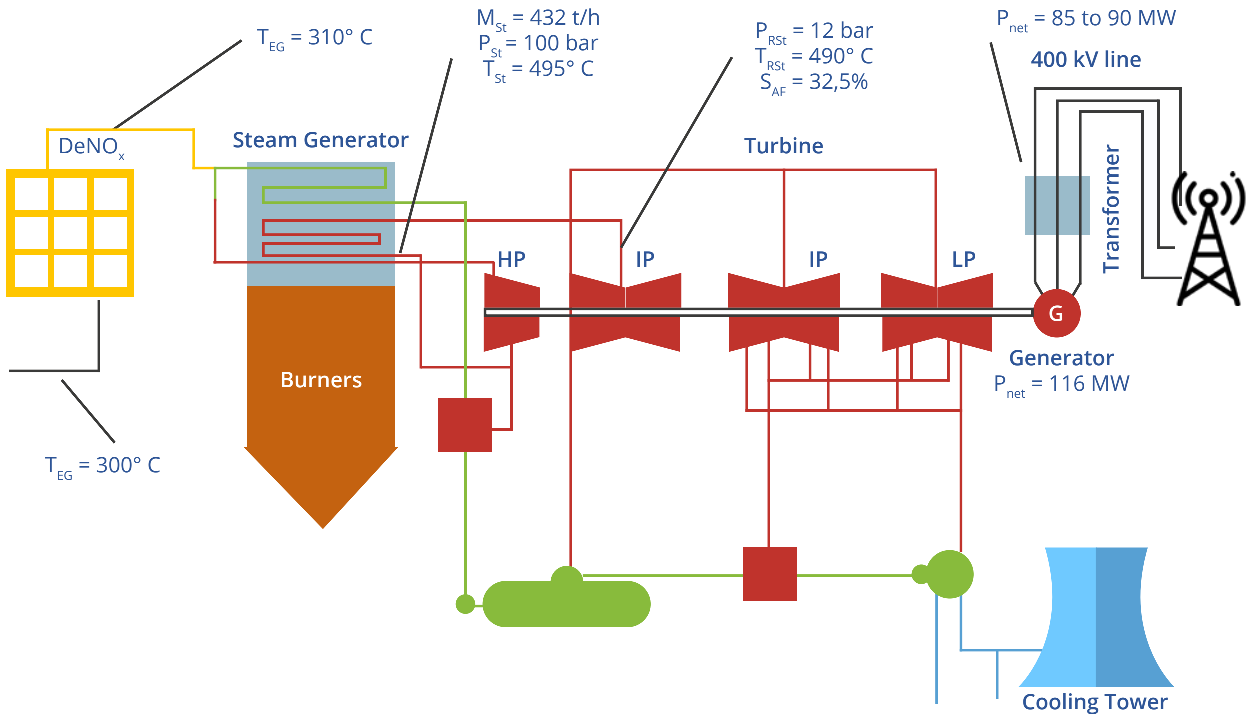


Figure 9. Operational parameters for the new load load operation in Bexbach power plant (Heinzel et al., 2012)

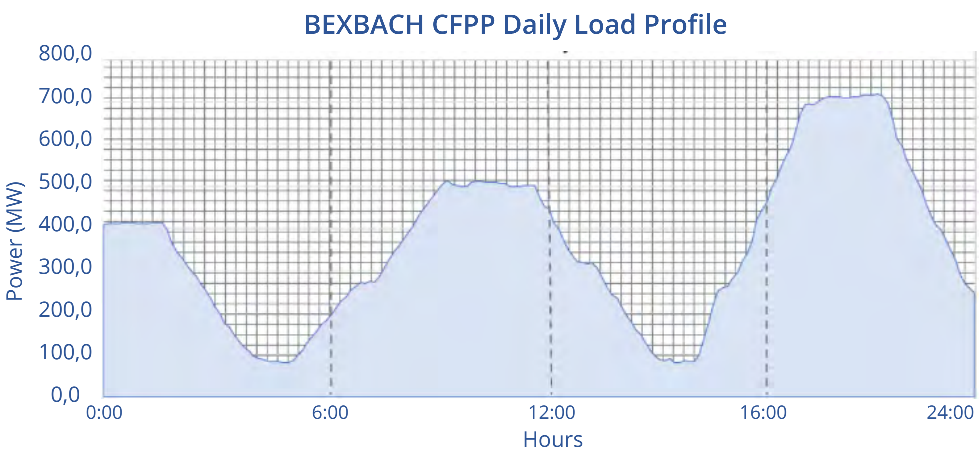


Figure 10. Typical daily load profiles operating at full and minimum loads (Heinzel et al., 2012)

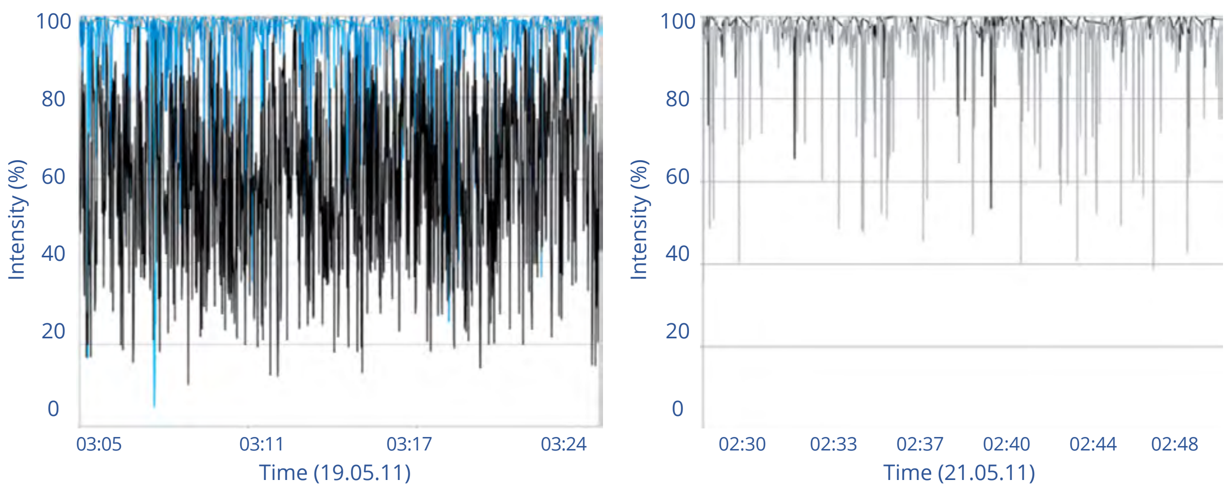


Figure 11. Comparison of the two mills (left) and single mil (right) l operation in Heilbronn unit 7 trial run

Market Structure that Indirectly Incentivises Flexible CFPPs Operation

The following part covers German electricity market design, including the mechanisms and financial reimbursement in balancing generation and load from power plant units. The majority of information presented here can be found in detail in (Enrst & Weiwei, 2020).

Market design for balancing mechanism - Keeping the load and generation balanced define one of the essential tasks of Transmission System Operators (TSOs). In Germany, part of the task can actually be carried out by market participants, known as the Balancing Responsible Party (BRP). BRP can be in the form of a consumer or a group of consumers, consisting of residential or small commercial customers pooled together by local council or utility company. Each BRP is allowed to perform its own load forecasting and search for a generator on the market that suits their energy needs. Once found, all energy transactions, including planned schedule for energy deliveries, between the two must be provided to TSOs. TSOs will check whether the proposition is a match and the power system itself is balanced or not. If met, then the plan is a go. Figure 12 illustrates flow of the process.

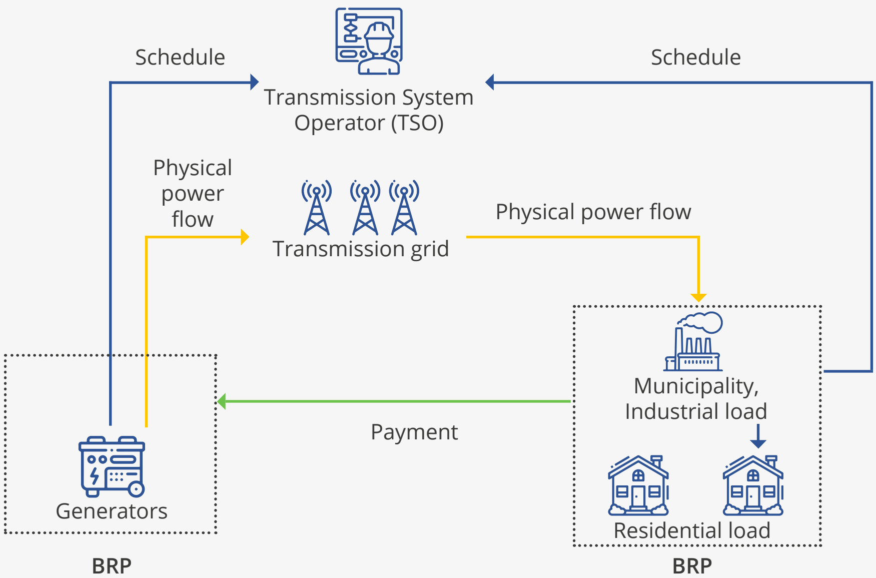


Figure 12. Illustration of the balancing mechanism in Germany (Enrst, 2015)

Germany's balancing mechanism is done through a specific market design, known as reserve market. The market itself recognises two prices, namely capacity and energy prices. The capacity price is specifically designed to remunerate suppliers for reserving positive or negative balancing capacity during a certain amount of time (Bundesnetzagentur, n.d.). The energy price[18], on the other hand, is paid out once at the time of previously reserved balancing capacity is activated.

There are three types of reserves recognised within Germany's reserves market, namely Primary Control Reserve (PCR), Secondary Control Reserve (SCR) and Tertiary Control Reserve (TCR). The difference between these types of reserve is on the ramp rates or activation time during their deployment. Figure 13 exemplifies a situation where a frequency drop is detected within the power system. In the first instance, the PCR is deployed due to the sudden drop. The reserves are characterised by fast-response reserve type. The task is then carried

[18] The energy price in the reserves market is designed to be higher in the reserves market than in the wholesale electricity market, providing a strong incentive for the supplier to operate its power plants flexibly.

out next automatically by the SCR to further restore the frequency. The TCR, which is usually a slow-response reserve type, is finally deployed to complete the frequency restoring process. The activation is done manually. Being a tertiary, this type of reserve can be activated depending on the length of the imbalance. For a long one, e.g. power plant failure, TCR is obliged for deployment. However, for a short one, e.g. imbalance due to change of delivery schedule at the full hour, TCR may be left inactive. Details on the three types of reserves are summarised in Table 4.

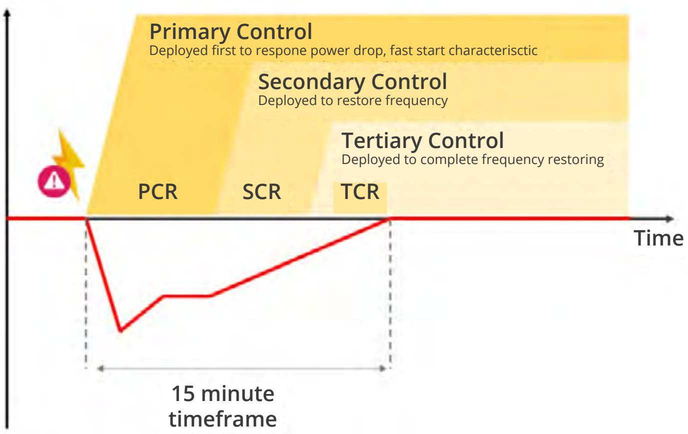


Figure 13. The use of different reserves type in Germany reserves market (Enrst & Weiwei, 2020)

Indicator	PCR	SCR	TCR
Time to response	30s	5 mins	15 mins
Reaction time	5s	30s	15 mins
Price components	Capacity	Capacity and Energy	
Offer made	One offer for positive and negative PCR	One offer for positive and negative SCR/TCR	
Minimum offer	1 MW	5 MW, minimum 1 MW under certain condition	
Tendering process	Weekly basis, bid submitted only for the capacity price[19]	Daily, bid submitted for both the capacity and energy prices	

Table 4. Further characteristics of different types of reserves in Germany (Enrst & Weiwei, 2020; Yanan et al., 2020)

The reserve market has only a single participant, namely the TSOs. The TSOs act as buyers, as well as ones that set the rules and facilitate the market. The rules are supervised by Germany's federal network agency, Bundesnetzagentur. The transaction within the market is done through a tendering mechanism pay-as-bid, which means suppliers of reserves will receive the price they offered. The tendering includes a prequalification step to assess technical suitability in providing one or more types of reserves. Figure 13 provides an example of Germany prequalified capacity reserves for the market tendering process from suppliers with various primary energy sources, including hard coal and lignite, in 2019. Once qualified, these suppliers are asked to send their bids to TSOs tendering process. Upon the outcome of the tendering process, the selected supplier is obliged to stay available with its capacity.

[19] With the PCR, the capacity price acts as an incentive for the losses that may incur from letting the reserves stay available until the TSOs call for activation. This also applies to SCR and TCR.

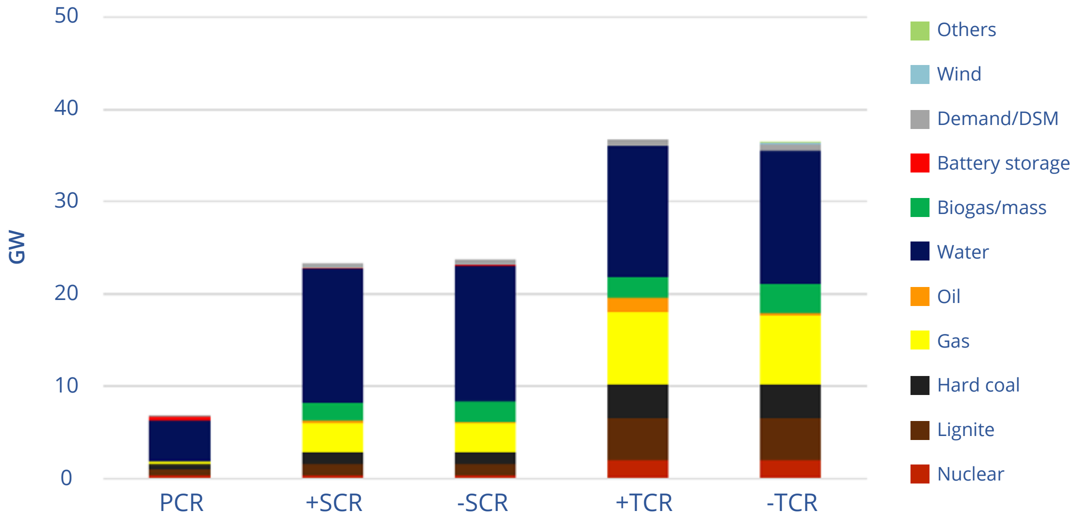


Figure 14. Prequalified balancing capacity (in GW) in Germany from various primary energy source (Consentec, 2020)

In Germany, capacity for the reserves can be served from both the supply-side and demand-side of the power system. The latter is done through controllable load. This usually comes from industries, such as aluminium smelters and/or electrolysers in the German case. When needed, their large electricity consumption can be reduced or interrupted on short notice for a certain period of time, resulting in them having a positive reserve capacity. Most power generation and storage systems fall into the supply-side category. This includes gas and coal. Whilst these power plants are in operation, they can provide the reserve capacity. As an illustrative example, consider a CFPP with a generating capacity of 600 MW and minimum load capacity of 300 MW. If the power plant is operated at a capacity of 550 MW, the remaining 50 MW capacity is available as positive reserve. Therefore, when the left over is required by the TSOs, the power plant ramps its output capacity to 600 MW. The operator will then be paid with the energy price. The pricing itself is actually in the reserves market, hence incentivising the power plant to operate flexibly, in this case by ramping up its output to meet the demand.

4.1.2. India

Recent Electricity Supply and Demand Profiles in India

In 2021, India's CFPP installed capacity amounts up to 203.2 GW out of 393.4 GW. As for the renewables, they account for 38.3% of installed capacity mix, with the VREs holding up to 22.4% (Ministry of Power, n.d.; MNRE, n.d.). However, the considerable share of installed capacity is not reflected in the actual generation mix. For the first 10 days of November 2021, the highest contribution from the VREs in the generation mix stopped at 8.91% that took place on the 6th November. Nevertheless, the CFPPs are still in the forefront of meeting India's electricity demand, covering 71-75.3% of the generation mix in that period of time. This is clearly reflected in Figure 15. The demand is observed to be its lowest on the 5th November. Coincidentally, the CFPP generation mix is also at its lowest. The VREs, on the other hand, began the increasing trend until reaching its peak the next day. Despite being largely driven by the CFPP, the VREs does slightly nudge the supply, as particularly observed on the 6th November. Despite the current generation mix presented here, India has actually devised a plan on how to allow further integration of renewables into the power system through shifting the CFPP operation towards flexibility. CEA has even suggested that each CFPP should be operated with at least 1%/min ramp rates (CEA, 2019).

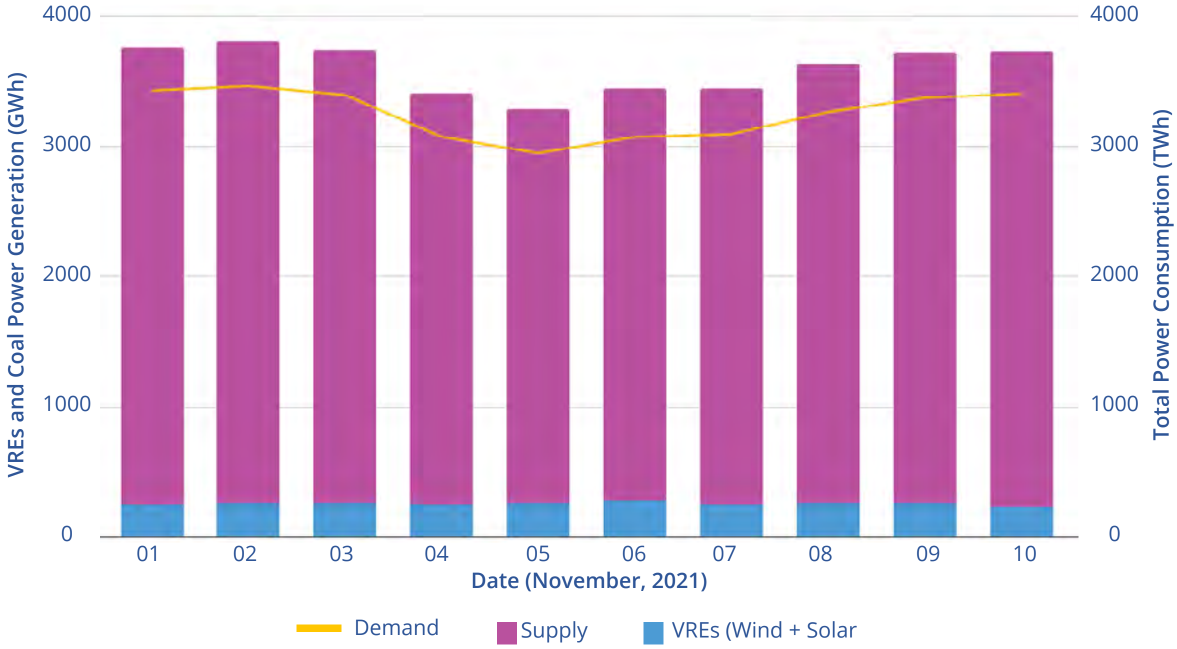


Figure 15. Profiles of VREs and coal generation mix, as well as the demand, in India from 1st to 10th November 2021

India Trial Runs on Flexible CFPPs

Unlike Germany, India is relatively new in operating a CFPP flexibly. A number of trial runs have been carried out in India. These trial runs were expected to define the power plants baseline capability, which would then be analysed to give recommended measures, outlining specific areas of change in operational practises and retrofits/upgrades for flexible operations. Prior to these trial runs, Indo-German Energy Forum (IGEF), through its subgroup on "Flexibilisation of Thermal Power Plants", has initially laid out the foundation by forming a task force that has produced flexibility toolbox and reference book, held a series of workshop and training in the concepts of flexibility, and provided suggestions in optimising India's regulatory framework to adapt to the needs for flexible power plants (IGEF, n.d.). Furthermore, India, with the assistance of USAID through Greening The Grid-Renewables Integration and Sustainable Energy (GTG-RISE) initiative, has identified 302 CFPPs with a total generating capacity of ~82 GW nationwide that are required to operate flexibly (USAID & Ministry of Power, India, 2020). A quarter of these units are expected to be retrofitted to be able to run flexibly. A panel headed by India's Central of Electricity Authority (CEA) has already identified a change needed in India's tariff system to aid the flexible operation of these CFPPs (Sengupta, 2019). Through the change, the panel also hinted at the requirement to incentivise the procurement of all necessary equipment to retrofit these CFPPs. Figure 16 shows distribution of flexibility potential in each state in India.

Dadri Block 6 - The country has just begun its trial on flexible operation of CFPP in June 2018. The trial aimed at lowering the minimum load down to 40% at NTPC Dadri subcritical coal-fired power plant block 6 operated since 2010 with a generation capacity of 500 MW (Indo-German Energy Forum, n.d.). The trial was deemed a success as they were able to sustain a lowered minimum load operation at 200 MW for four to five hours. The team also managed to drive load ramps of 5 MW/min (1%/min) and 15 MW/min (3%/min) within the 200 MW and 500 MW range. Upon the success of the trial, the team, consisting of EEC and VGB, was preparing an implementation plan to ensure safe and reliable operation at 40% load. From the preliminary study on flexibilisation of thermal power plants in India, the cost implication of such an operation in the Dadri Block 6 will range between US$ 1.2 - 2.7 million per unit (IGEF, 2017). The cost covers the implementation condition monitoring equipment, start-up optimization procedures, flame detection sensor, and further analysis using Finite Element Method (FEM).

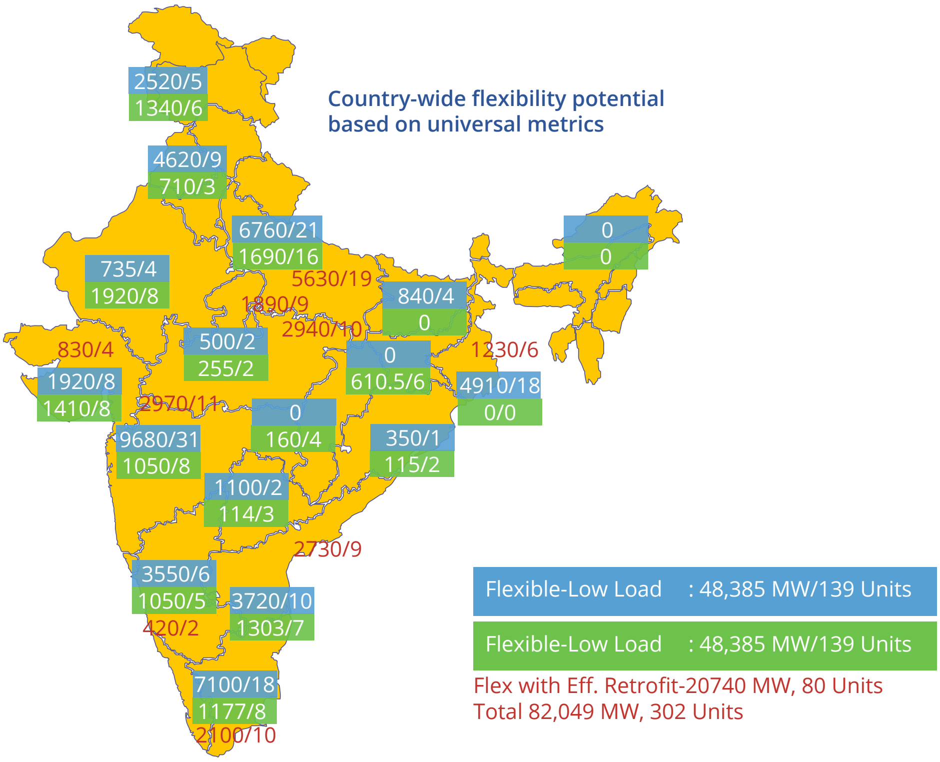


Figure 16. Planned flexible CFPPs in India; categorised into flexible to run on low load (Flexible-Low load), flexible to run with frequent daily start (Flexible-Daily Start), and flexible to run with efficient retrofit (Flex with Eff. Retrofit) (USAID & Ministry of Power, India, 2020)

The test run also produced a few recommendations to ensure stable operation at 40% load as listed below, addressing improvements that should be made on different CFPP subsystems (Eck, 2018).

1. Optimization of existing controls
   - Automatic Mill Operation (Mill Scheduler)
   - Main Steam Temperature Control
   - Reheat Steam Temperature Control
   - Automated Start of Fans and Pumps
   - Flue Gas Temperature Control

2. Transparency about process conditions
   - Thermal feasibility study
   - FEM analysis
   - Condition monitoring

3. Installation of a modulating mechanism type recirculation valve across the boiler feed pump to enhance the controllability of the process

Mouda Unit 2 - The supercritical coal-fired power plant has a generating capacity of 500 MW and started commercially in 2013. The trial was conducted by NTPC with the assistance from GTG-RISE, a USAID-funded program, experts and Bharat Heavy Electricals Limited (BHEL) in September 2019. Therefore, at the time of the trial, the power plant had already been operating for 6 years. The team successfully ran the power plant with a minimum load of 40%, down from 55% (USAID & Ministry of Power, India, 2020). No added equipment was implemented in support of the trial run. The lowering of the minimum load was achieved by adjusting the operational procedures, following the ones developed by GTG-RISE and BHEL.

Ukai Unit 6 - In March 2020, GSECL, another power plant operator in India, successfully conducted a trial run on its 500 MW Ukai subcritical power plants for 3%/min ramp rates, as well as low load operation at 40% (CEA, 2021; USAID & Ministry of Power, India, 2020). GSECL received its assistance in the trial run, also, from GTG-RISE experts and BHEL. The power plant was only 7 years old at the time of the trial run. No changes or additions in the power plant subsystems were made. The improvements were achieved by solely changing the operational procedures, similar step-by-step changes as outlined in the GTG-RISE and BHEL documentation.

Sagardighi Unit 3 - The trial run was conducted in June 2019 (CEA, 2021). The subcritical coal-fired power plant itself has a generating capacity of 500 MW and was commercially produced electricity in 2015. Hence, the power plant was just 4 years old during the trail run. BHEL was appointed to carry out the trial run, witnessed by representatives from Thermal Power Renovation and Modernisation (TPRM) division of CEA. The trial has successfully performed a minimum load test at 40%. The trial also performed tests on two ramp rate regimes to reach the new minimum load level, namely 1%/min and 3%/min. The 3%/min ramp rates were not performing as expected. During the trial, the ramp-up is rated at 1.6%/min and the ramp-down is rated at 2.6%/min. The 1%/min ramp rates, however, did partially perform well in the trial, by achieving the ramp-up at 1.1%/min and the ramp-down at 0.67%/min.

Evolving Electricity Market Design to Adopt Flexible CFPPs in India

Since the amendment of the Electricity Act 2003, electricity prices in India have been guided by the market of supply and demand (Kulkarni et al., 2016). The following will elaborate further on the market design in India that may encourage CFPP flexible operation, particularly on the balancing market.

Real-time balancing market mechanisms - In India, electricity is traded in the wholesale market between its participants, consisting of generators, traders, load despatch centres, and distribution companies (discom). Figure 17 illustrates the interactions amongst the participants. At the heart of the market is the load despatch centres, which are tasked to maintain the balance between the supply and demand through coordination with stakeholders in real time. Similar to the power system in Germany, a balancing mechanism and its market venue are also available in India's power market. The real-time balancing in India is met through a few market mechanisms. These are Deviation Settlement Mechanism (DSM), intra-day market and rescheduling, and Ancillary Services (AS) mechanism (CEF, 2020).

DSM was first implemented in 2014 by India's electricity regulator, CERC. It is essentially a frequency-linked mechanism that would penalise or incentivize generators for over drawl/injection or under drawl/injection of electricity from the agreed schedule (J. Satre & S. Deshmukh, 2018). During its first implementation, the mechanism imposed several salient features, including frequency band between 49.90 - 50.05 Hz and volume of deviation from scheduled to actual injection/drawal that is limited to 150 MW or of 12% of the schedule, whichever is low. More details of the features can be found in CERC (2018).

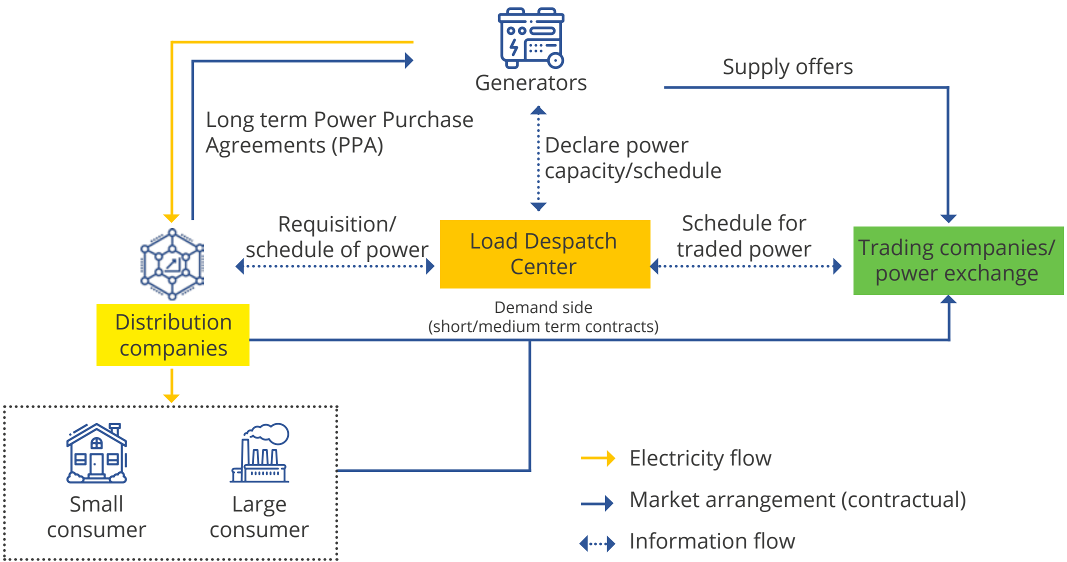


Figure 17. Illustration on wholesale market interaction in India (CEF, 2019)

The intra-day market serves as platforms for contingency transactions and power exchange. Unlike in the day-ahead market, the contingency transactions in the intra-day market happen bilaterally between discoms and generators. The intra-day power exchange, on the other hand, trades power to match the supply and demand in real time for a period of 15 minutes from 00.15 to 19.30 (IEX, 2020). The delivery itself is expected within the next 3.5 hours after the trading closure time. The last mechanism in real-time balancing is the rescheduling. Both the discoms and the generators can revise the agreed schedule within an hour of the actual delivery. The provision for the right to recall is designed to allow flexibility to the generators to vary their output and the discoms to meet their last-minute demand closer in real time (Staff of CERC, 2018).

Ancillary Services (AS) mechanism was introduced for the first time in 2016. The AS mechanism, otherwise known in regulatory terms as Reserve Regulation Ancillary Services (RRAS) (S. K. Soonee et al., 2016), enables load dispatch centres to pool together un-dispatched surplus from the CERC regulated generators in merit order and use them as reserves to maintain frequency stability in real time (Staff of CERC, 2018). These generators are paid for their fixed and variable cost along with a mark-up of INR 0.50/kWh. Source of funds for the payment comes from the DSM surplus pool. CERC has recently announced a draft that would include energy storage and demand response resources to be part of the AS and procured by means of market-based bidding mechanism. Three reserve types, as in the Germany reserves market, would be introduced through the drafted regulation (CERC, 2021; Colthorpe, 2021). However, there are two reserve types that are regulated in the document, namely Secondary Reserve Ancillary Services (SRAS) and Tertiary Reserve Ancillary Services (TRAS). Table 5 presents the proposed indicators for the draft regulation of these reserve types. It is expected that along with the successful trial run on the flexible operation the drafted regulation could allow the CFPPs to participate in the AS market and provide real time balancing power, whilst also getting incentivised from providing such an operation.

Indicator	SRAS	TRAS
Time to response	15-30 mins	15-60 mins
Reaction time	30s	15 mins
Minimum offer	1 MW	>100 MW
Tendering process	Day-ahead and real-time	

Table 5. Proposed indicators for the SRAS and TRAS (CERC, 2021)

Compensation for flexible operation in CFPP - Still in line with above, India, through the CERC, made changes to the grid code to reduce the minimum operating output of power plants from 70% to 55% of installed capacity as of 2018 (Powerline, 2018). The regulation, known as Sub-Regulation 6.3B of the Indian Electricity Grid Code (IEGC), also provides a compensation mechanism for plants that operate at part-load and with multiple start-ups (Approval of the Detailed Procedure for Taking Unit(s) under Reserve Shut Down and Mechanism for Compensation for Degradation of Heat Rate, Aux Compensation and Secondary Fuel Consumption, Due to Part Load Operation and Multiple Start/Stop of Units, 2017). These kinds of operations will result in the degradation of Station Heat Rate (SHR), Auxiliary Energy Consumption (AEC) and potential increase in the secondary fuel oil consumption. Table 2 provides the variables considered in the compensation calculation for each condition. The compensation is evaluated monthly, billed along the monthly bill, and submitted to the State Load Despatch Centre (SLDC) who will then issue the adjusted compensation statement to be paid by regional distribution utility company.

Compensation Variables	SHR & AEC	Secondary Fuel Oil Consumption
Operation applicable for compensation	Part-load; average unit loading (AUL) <85%	Multiple start-ups; number of start-ups > 7
Important parameters in the compensation calculation	Energy charge rate (ECR), which weights on % degradation in heat rate and % degradation in auxiliary energy consumption	- Number of start-ups - Volume of consumed secondary fuel oil in kL - Average landed price of secondary fuel oil for the year

Table 6. Compensation mechanisms as stipulated in the detailed operating procedure of Sub-Regulation 6.3B IEGC

Madhya Pradesh Electricity Regulatory Commission (MPERC) provided a case of a power plant unit with generating capacity of 200 MW to illustrate the calculation on the compensation mechanism[20]. The power plant operates under part-load and provides its electricity output to several beneficiaries, namely A, B, C and D. Beneficiary D is considered a pseudo-beneficiary, i.e. an IPP being in the beneficiary role. The simulated calculation for the compensation of SHR & AEC is summarised in Table A1 within the Appendix.

4.2. Key Takeaways

Key features and indicators of CFPPs flexibilisation from Germany and India sums up in table 7. The two countries provide staggering differences in the power plants' age range. As reflected from the table, the retrofit needs and costs correlate quite clearly with the power plants age. Germany has started such an operation earlier than India through retrofitting its ageing CFPPs. The cost ranges from €70 million to €215 million, depending on the retrofitting packages. Some are intended to rejuvenate or modernise the power plant, the rest are targeted for different improvements on the flexibility criterion. Plant modernization in Germany's CFPPs, e.g. in Neurath Block E, Zolling Unit 5 and Heilbronn Unit 7, has increased the plant performance, in terms of efficiency and CO2 emissions. In addition, it also improves the flexibility criterion. However, it should be realised that this kind of retrofitting package does come with a large sum of cost.

On the other hand, it is interesting to see that all flexibilisation in India is still pilot projects at young power plants, ranging between 4 and 8 years old. As mentioned earlier, these power plants were successfully operated at a minimum load of 40% and improved ramp rates between 1%/min and 3%/min. During the trial runs, only adjustment to the operational procedures was carried out without additional equipment added to the power plants subsystems. The India's way in flexing its CFPPs operation can be an alternative for countries with young CFPPs, which in the context of this paper fit into Indonesia's CFPP characteristic.

In terms of market design, both countries agree on a market design that accommodates real-time balancing and provides incentives for ancillary services. Such a market would help and encourage generators to willingly provide their power output as requested, as the financial mechanism in the market incentivises flexible operation in conventional power plants, including the CFPPs. Furthermore, India's regulation adds further compensation mechanisms to generators that can operate flexibly, in this case to run with lower minimum load and multiple start-stop operation. Calculation on the compensation is based on the degradation of power plant heat rates, increased auxiliary energy consumption and secondary fuel oil consumption.

Encouraging markets and supportive regulatory framework are indeed what Indonesia requires in order to enable CFPP flexible operation, a topic to be discussed in the following section.

[20] This is clearly detailed in Approval of the Detailed Operating Procedure for taking unit(s) under Reserve Shut Down and Mechanism for Compensation for Degradation of Heat Rate, Aux Energy Consumption and Secondary Fuel Oil Consumption, due to Part Load Operation and Multiple Start/Stop of Units under Reserved Shut Down (RSD) (2020)

Country	Power Plants	Age (at the time of retrofit or trial runs)	Gen. Capacity	Retrofitting Cost (Year)	Retrofit & Operation Modification	Improved flexibility criterion (post-retrofit or post-trial runs)			Performance Indicators		
						Min. load	Ramp-rates	Start-up Time	Power Output	Efficiency	CO_2 Emissions
Germany	Neurath Block E	37 years	600 MW	€70 million (2011)	Plant modernization	43% (↓39%)	2.38%/min (↑243%)	3hrs 15 mins (↓1 hours)	n.a.	(↑0.6%)	(↓100 kilo tons/year)
	Weisweiler Unit G	32 years		€215 million (2006 to 2007)	· Additional gas turbine units (€150 million) · Digital control system and plant engineering in Unit G (€65	(↓170MW)	(↑1.67%/min)	n.a.	(↑6.6%)	(↑)[21]	(↓11%)
	Weisweiller Unit H	32 years				48% (↓28%)	n.a.				
	Zolling Unit 5	25 years	450 MW	€80 million (2011)	· Digital control system (€2.5 million) · Start-up optimisation algorithm using BoilerMax · New steam turbine stages	n.a.	n.a.	(↓15 mins)	(↑12 MW)	42.3% (↑1%)	(↓12%)
	Bexbach	28 years	721 MW	Not required	Single mill burner operation	12.5% (↓64%)	n.a.	n.a.	n.a.	n.a.	n.a.
	Heilbronn Unit 7	26 years	800 MW	n.a.	· Single mill burner operation · New steam turbine stages	12.5% (↓50%)	n.a.	n.a.	n.a.	(↑1.1%)	830 gr/kWh (↓2.8%)
India	Dadri Block 6	8 years	500 MW	Trial runs	Operational procedures adjustment without retrofit	40%	1%/min & 3%/min	n.a.	n.a.		
	Mouda Unit 2	6 years				40% (↓15%)	n.a.	n.a.			
	Ukai Unit 6	7 years				40%	3%/min	n.a.			
	Sagardighi Unit 3	4 years				40%	1.1%/min & 2.6%/min	n.a.			

Table 7. Summary of the lesson learned from countries with flexible CFPPs operation

[21] The report only indicates the increase qualitatively, without mentioning any number.

5

ENABLING CFPP FLEXIBLE OPERATION IN INDONESIA

The following section will specifically address coal-fired power plants (CFPPs) and how to enable flexible operation within the power plants. This is a relevant topic to Indonesia's power sector that is still dominated by CFPPs and has a goal in increasing the renewables' share in the generation mix. The outcome of this section would then serve as a preliminary study that shows the feasibility of operating Indonesia's CFPP flexibly.

5.1. CFPP Main Characteristics in Indonesia

In the early 90s, Indonesia has been solely relying on oil-based power plants, as presented in Figure 19. This has changed from 1995 onwards. Having first relied on natural gas, the electric consumption was further supported largely by coal for almost 20 years. Steep increase in the electric generation from coal is observed from 2010. There are at least three government programmes that have accelerated coal-based generation, namely 10,000 MW Fast Track Programme 1 (FTP-1) commenced in 2006, 17,428 MW FTP-2[22] commenced in 2010 and 35,000 MW programme[23] commenced in 2015. As presented in Figure 18, the consumption is increasing quite significantly, 71,220 GWh increment between 2000 and 2010 to 110,780 GWh increment between 2010 and 2020. Within the same period, coal-based generation continues to dominate Indonesia's generation mix. The matching trend between the consumption and coal-based generation indicates an undoubtedly strong dependence of Indonesia's power sector on the unsustainable source of energy.

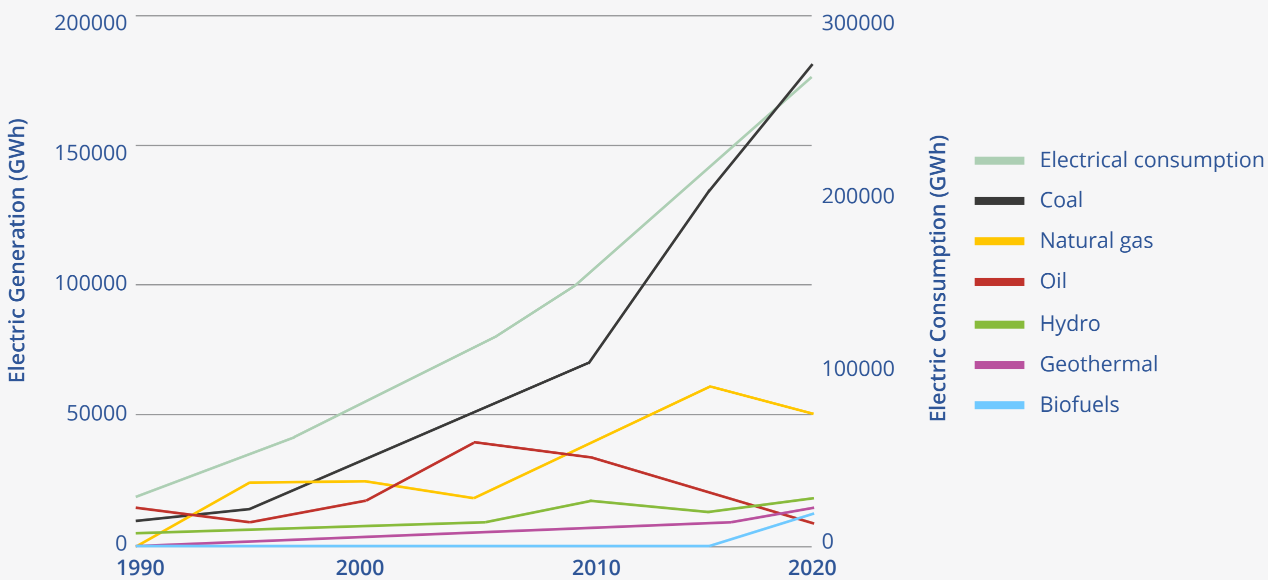


Figure 18. Electric generation mix of different sources and consumption in Indonesia between 1990 and 2020 (IEA, n.d.)

As an emerging economy, Indonesia's CFPP units are about 9 years old on average. This is plainly depicted in Figure 19, which provides an overview of 225 CFPP units age distribution[24] for each power range. The figure indicates an increasing trend of coal-based generation from the mid 90s and continues until today. The oldest CFPP in Indonesia is Suralaya Unit 1 & 2, situated at the far northwest tip of Java in Cilegon, Banten. Each unit has a generating capacity of 400 MW[25] and was built in 1984 and 1985, respectively. As can be seen from the figure, most CFPP units are below 15 years old, with the majority of these plants having a generating capacity between 15 MW and 300 MW. There is, however, a considerable number of CFPP units within the 21-25 age group.

[22] 10,520 MW (60%) comes from the coal-based generation
[23] 19,813 MW (55,61%) comes from the coal-based generation
[24] The distribution in this and subsequent figures include power plants owned by PLN, IPP and PPU. Apart from the ownership, other CFPPs electricity end-users, such as mining, cement, and pulp and paper industries, are also included in the distribution
[25] These units have actually undergone Renovation and Modernisation (R&M) between 2010 and 2012, increasing the capacity by 40 MW to 440 MW, each (Source: (CEA, 2013))

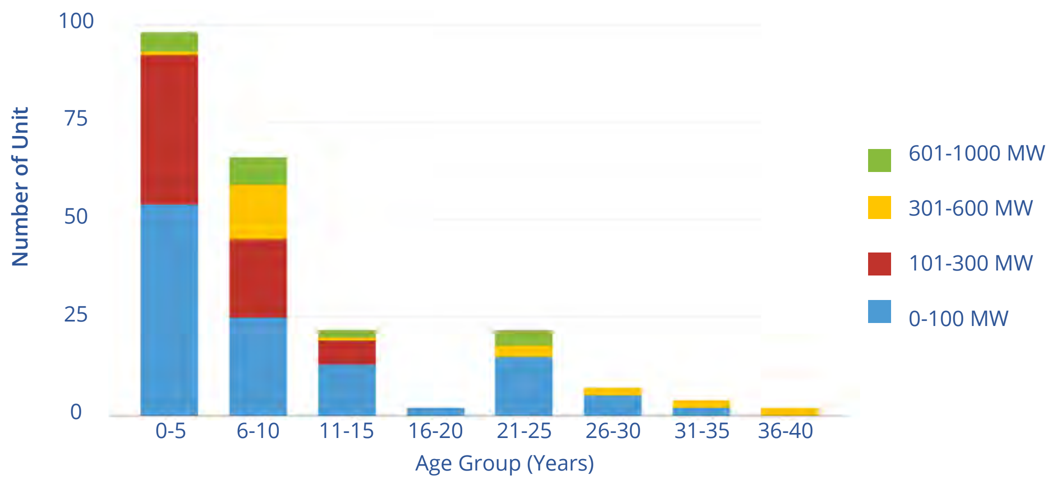


Figure 19. Current CFFP age distribution in Indonesia per age group (Years) and power class (MW)

In terms of boiler technology, most CFPP units in Indonesia are still using the subcritical, as presented in Figure 20. Included in the distribution depicted from the figure are three boiler technologies, namely subcritical (including the circulating fluidized bed, CFB), supercritical and ultra supercritical. The supercritical and ultra supercritical technologies have just been incorporated into Indonesia's power system since 2001. Both technologies only contribute 3,465 MW and 2,982 MW to the total capacity generation, respectively. With regards to the generating efficiency, the subcritical CFPP has a typical efficiency of 34.3%, whilst the more advanced ones, i.e. the supercritical and ultra supercritical, each has a typical efficiency of 38.5% and 43.3% (MIT, 2007), respectively.

Further details on the CFPPs characteristics on each major island in Indonesia are presented in the Appendices (Figure B1 - B3). From these figures, it can be observed that most of the young power plants are located outside Java-Madura-Bali (Jamali) and Sumatra islands. Around 55% of CFPPs at the age of between 0 - 20 years old are found outside Jamali and Sumatra. For the age group of above 20 years old, the situation is flipped, with ~66% of CFPPs in this group found in Jamali and Sumatra. As explained in the previous section, the age of the power plants could be a factor to be considered in the retrofitting packages for flexible operation. Furthermore, from Germany and India's experience, it can be learned the implications of the age to the cost of investment to make CFPPs flexible. As indicated earlier, retrofitting an ageing power plant will cost more, in terms of investment, than the young ones as the latter only require far cheaper interventions, or even no interventions at all, to make it flexible. Therefore, mapping out power plants in Indonesia's power systems according to the age group might be valuable in setting up flexible operation plans.

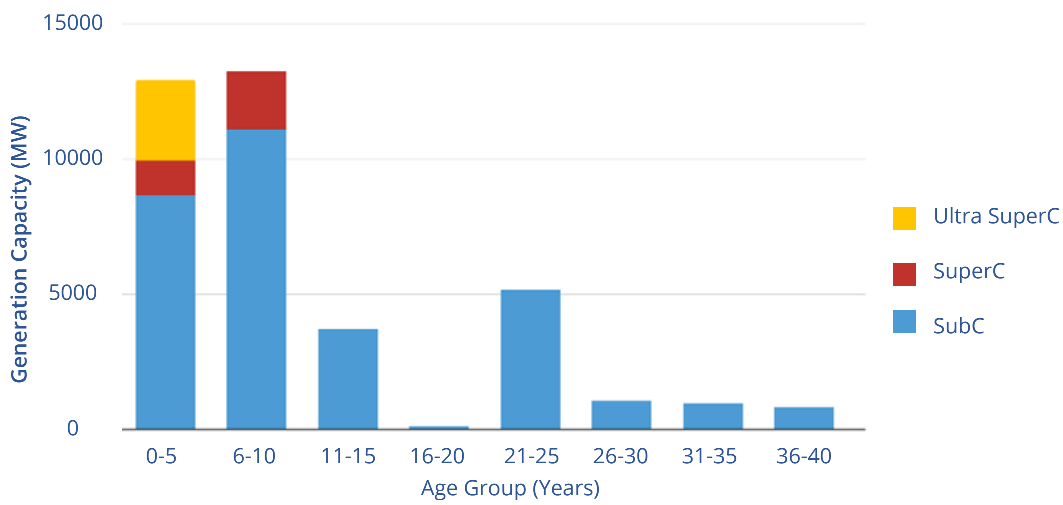


Figure 20. Steam cycle technology utilised in Indonesia's CFPP unit

Another consideration that can be factored in the decision to operate CFPPs flexibly is electricity oversupply. According to the latest PLN RUPTL, the ideal reserve margin for the Jamali system ranges between 35% (PLN, 2021). Outside the system, the reserve margin is relaxed to 40% due to the scarcity of power generation units. Indonesia currently faces electricity oversupply due to low demand during the COVID-19 pandemic. The Jamali system reserve margin has already exceeded its ideal level, rated at 46.8%. In the Sumatra system, the reserve margin is even higher at 55%. It is anticipated that the electricity surplus will continue until 2028 (Yanwardhana, 2021). The Jamali and Sumatra systems are forecasted with 40-60% and 30-56% reserve margins, respectively (Hamdi & Adhiguna, 2021). This is partly compounded by upcoming completion of new large-capacity power plants that amount up to 12,998 MW in terms of generating capacity until 2026. Hence, the oversupply in the Jamali system is projected to increase to 61% by 2026 (Mudassir, 2021).

5.2. Case Studies of Indonesia Typical CFPPs

5.2.1. Flexible Operation Implications on CFPPs Performance and Emissions

As elaborated in the previous section, there are several yardsticks for a CFPP to operate flexibly, namely minimum load, ramp rate and start-up time. Table 8 presents the performance data of a typical 100 and 600 MW CFPP. These numbers represent the landscape of Indonesia's typical CFPP. This will serve as a baseline for a rough comparison with expected performance output from a retrofitted CFPP.

Plant Specifications	Unit A	Unit B	Unit C
Nominal Capacity (MW)	100	600	100
Age group (Years)	21-25	21-25	0-5
Steam cycle technology	Subcritical	Subcritical	Subcritical
Minimum load (%)	55	79	38
Ramp rates (%/min)	1	0.58[26]	1
Net generation efficiency at full load (%)	23	36.55	30.76
Estimated net generation efficiency at minimum load (%)	21.73	35.83	25.44
Fuel supply specific CO_2 emissions ($gramCO_2/kWh_{th}$)[27]	316.88	332.21	326.51[28]

Table 8. Indonesia's typical 100 and 600 MW performance data

Of all the flexible criteria, lowering the minimum load poses a clear influence on the performance of the CFPP, negatively impacting the power plant efficiency. On the other hand, reducing the start-up time does not influence the CFPP performance. This also applies to increasing the ramp rates. Some measures discussed in previous sections, in fact, improve the CFPP performance, as in the case of repowering at the Weisweiler power plant, Germany. Figure 21 illustrates the effect of reducing the minimum load to the power plant efficiency. As estimated by Fichtner (Agora Energiewiende, 2017), reducing a CFPP minimum load by 20% points through retrofit would cause a decrease in the efficiency by 2% to 5%. A decrease in the efficiency means an increase in the Net Plant Heat Rate (NPHR). As a consequence of that, CO_2 emissions will increase as the electric generation (kWh) requires more heat input (kcal) into the system, obtained from burning more coals. A reduction of 1% in the NPHR causes 1% reduction in the CO_2 emissions, as explained in (Hansel, 2014). Therefore, 1% increase in the NPHR would result in the opposite outcome.

[26] Historically, the plant was once operating with a ramp-rate of 1.67%/min (10 MW/min). However, during the course of such operation, it resulted in a number of damages to the plant's subsystems, such as pipe leakage etc. To avoid further damage, the plant has been operating with a ramp-rate of 0.58%/min (3.5 MW/min).
[27] The plant specification is calculated from the proximate and ultimate analyses of the coal supplied to each unit, extracted from a report written by BCRC-SEA (2017).
[28] The number is obtained from averaging the fuel specific CO2 emissions calculated from different CFPP units with the same coal supplier and, of course, source.

Scenarios Considered: IESR Projection in 2030

IESR recent study on the capacity expansion and power flow analysis of high share of VREs, i.e. wind and solar energies, within Indonesia's four major power systems, i.e. Java-Bali, Sumatra, Kalimantan and Sulawesi, is possible to be actually implemented. Part of the study was looking specifically at 2030, in which the renewables contribution to the national generation mix already hit 33%, with the VREs contributing to around 24% of the mix. The renewables contribution projected in the study is ~10% higher than what has been indicated in PLN's electricity supply business plan, RUPTL 2021-2030. The high share of renewables in the system signifies the need to operate CFPPs flexibly.

One of the assumptions included in the study was the retrofit program that would enable the CFPPs to operate flexibly. A schedule for the retrofit program for all CFPPs has also been produced in the study, with a timespan between 2021 and 2030. One flexible operation criterion considered was the reduction of CFPP minimum load, from 50% to 30%[29] of the P_{nom}. This assumption was applied to all CFPP units within the systems considered. The selection of such a criterion was based on the fact that CFPP operation under lower minimum load would help the power plant to avoid expensive and CO_2 intensive shutdowns and start-ups (Agora Energiewiende, 2017). This is further compounded by the disadvantages of frequent shutdowns and start-ups that may strain the power plant's components and, therefore, reduce their lifetime. An analysis that discusses scenarios whereby these typical power plants undergo different flexible operational modes within limited time is presented next.

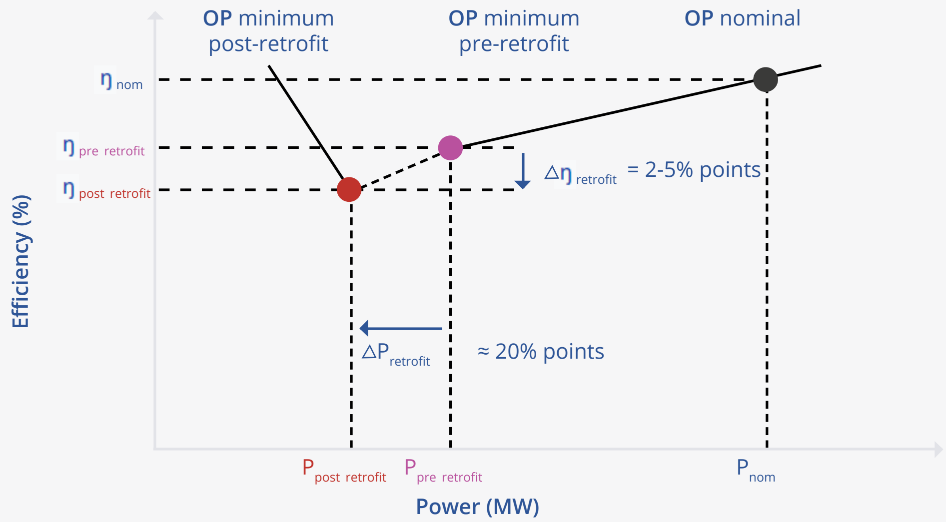


Figure 21. Reduction in the efficiency as the result of lowering CFPP minimum load (Agora Energiewiende, 2017)

Sumatra system - The island of Sumatra is blessed with a reasonable amount of renewable energy and the diversity of its sources, such as solar, hydro and geothermal, providing enough generation to meet the island's system future electricity demand. The generation share of renewables is projected to reach 39.5% by 2030. Geothermal holds the highest generation share amongst other renewables, rated at 12.41%. The hydro and solar PV plants within the system are predicted to be 6.78% and 9.05%, respectively. The proportion of these renewables can be observed from Figure 22 and 23, which depict the prediction of electric generation mix, including coal, gas and renewables, and consumption profiles of the Sumatra system during the two days operating

[29] Our study does not look into the lowest minimum load that a CFPP could achieve, while assessing the implication to the power system. Hence, the lowest minimum load was fixed at 30%. The number could actually be lower than that, reaching as low as 20%.

period for high and low solar irradiations. During the inception of solar PV generation, observed between 05.00 and 17.00, its output is shown to be the one completing the remaining generation to meet the demand. However, even with such inception from the solar PV plants, the majority of the demand is still being shouldered with the generation from burning the coal. The generation profiles of the power plant in both figures are observed to be relatively stable, with little hourly fluctuations. This is clearly a sign that the majority of CFPP units in the Sumatra system are still projected to be base load.

In this study, a 100 MW CFPP unit is taken into consideration, designated as unit A. The rationale behind the selection of the capacity is based on the fact that the majority of the CFPP units developed in Sumatra are below 300 MW, as mentioned earlier. In addition, it would be also interesting to observe how small CFPP reacts to the system generation landscape that has a noticeable proportion of renewables, e.g. solar, hydro and geothermal. Figure 24 displays the unit load operation during high and low solar irradiations, i.e. High SI and Low SI. In both cases, the unit can be observed to operate at 30% load only for less than 2 hours. More rampings happen during the high solar irradiation, compared to a single ramping observed during the low solar irradiation. This is a reasonable response, particularly in the latter case where the solar PV is expected to be low in the generation.

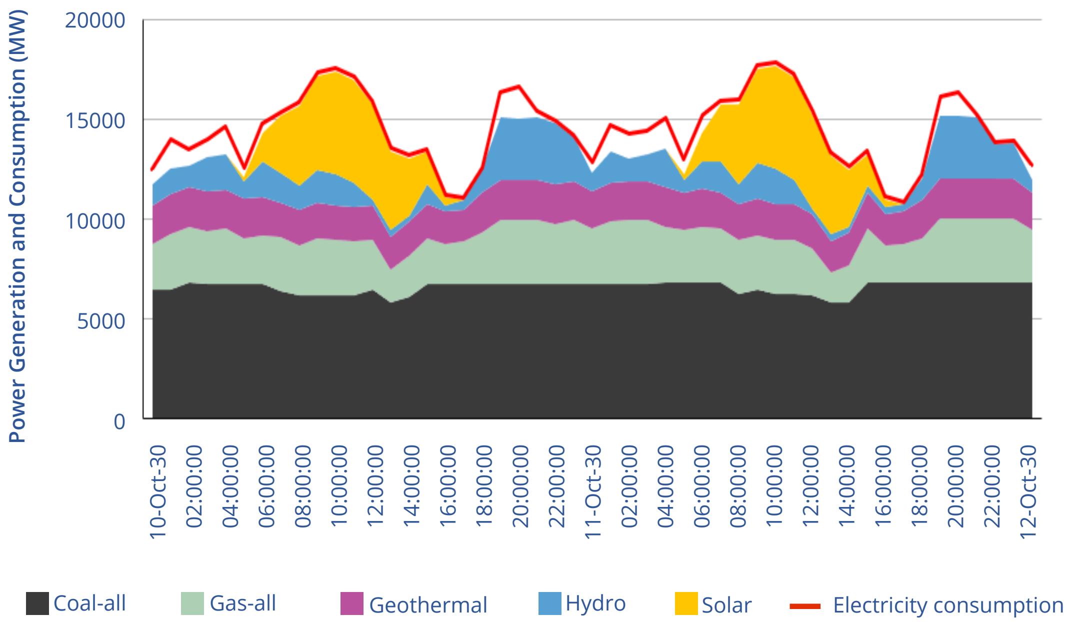


Figure 22. Power generation from CFPPs, GFPPs and renewable plants (solar PV, hydro and geothermal) and consumption within Sumatra system during high solar irradiation in 2030

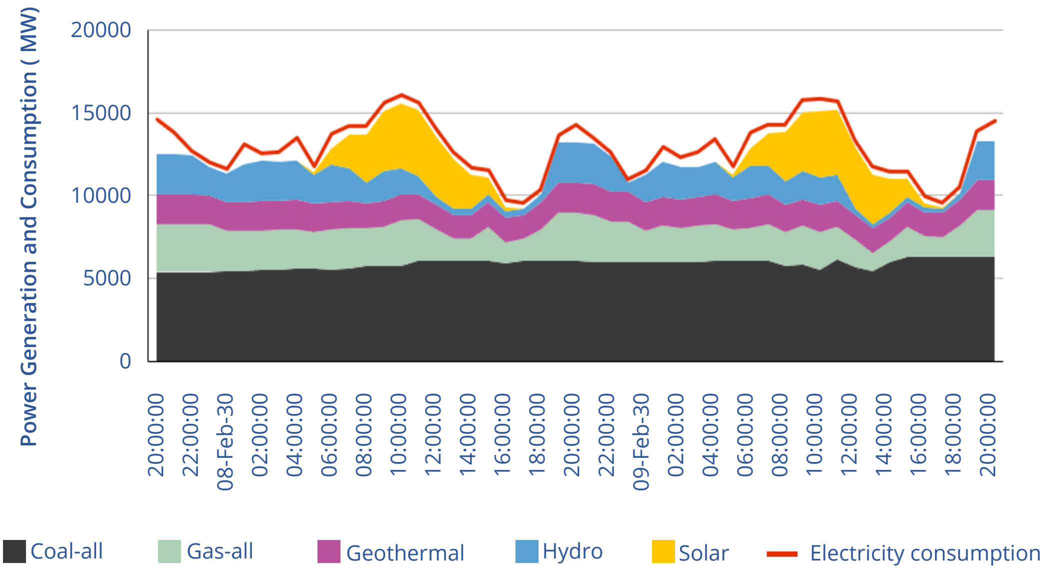


Figure 23. Power generation from CFPPs, GFPPs and renewable plants (solar PV, hydro and geothermal) and consumption within Sumatra system during low solar irradiation in 2030

Java-Bali system - Solar energy is projected to be at forefront in meeting Indonesia's future electricity demand, solely due to its vast technical potential and competitive price. Within the Java-Bali system alone, the potential capacity and yearly potential generation have been estimated to be, respectively, over 2,700 GWp and 3,700 TWh/year (IESR, 2021). Figure 25 presents the predicted operation profiles of all CFPP units and added solar PV plants within the system. The generation share of renewables is projected to reach 31.91%, whilst the solar PV plants generation is predicted to be 25.55%. It was predicted that during this time of the year solar irradiation is at its highest. Hence, it can be clearly observed that during the high inception of solar PV plants production between 05:00 and 17:00 each day, all CFPP units, as well as all Gas-fired Power Plant (GFPP) units, are backed down and cumulatively operating with low load at 65.2%.

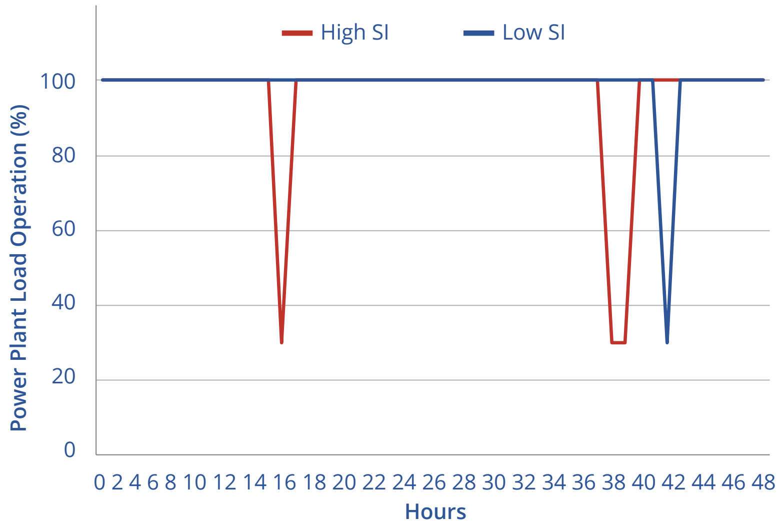


Figure 24. Typical 100 MW CFPP load operation in Sumatra system during high (High SI) and low (Low SI) solar irradiances

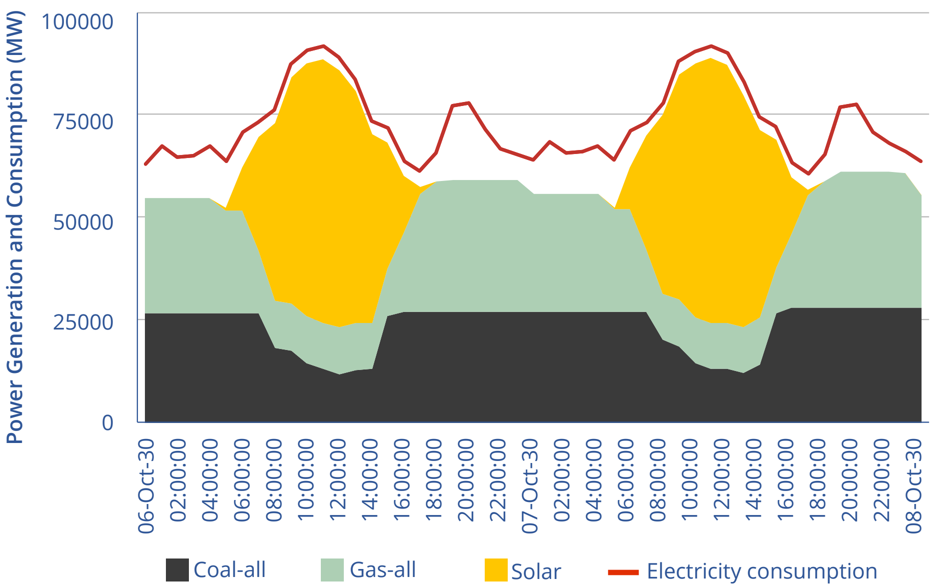


Figure 25. Power generation from CFPPs, GFPPs and solar PV plants and consumption within Java-Bali system during high solar irradiation in 2030

Another case presented in Figure 26 shows a different prediction on the solar PV power generation. As observed, the peak of the solar PV plants power generation is projected to be ~18 GW lower than the one in the high solar irradiation period. This consequently affects the operation of all CFPP units within the system. Unlike in the first case, the generation for these units is observed with little hourly variation, even during the high generation from the solar PV, between 05:00 to 17:00 each day. During that period of time, the dip in the coal-based generation is not as deep as in the first case, shown in Figure 25. On the contrary, all GFPP units are observed to be shifting their operation to the low load, albeit with relatively shallow dip compared to the first case. Hence, it seems that only the GFPP units are still affected by the inception of solar PV power generation. This is perhaps due to the lower electricity consumption than in the first case, prompting the system to choose turning down the load from the GFPP units that are relatively easier to perform than the CFPP units.

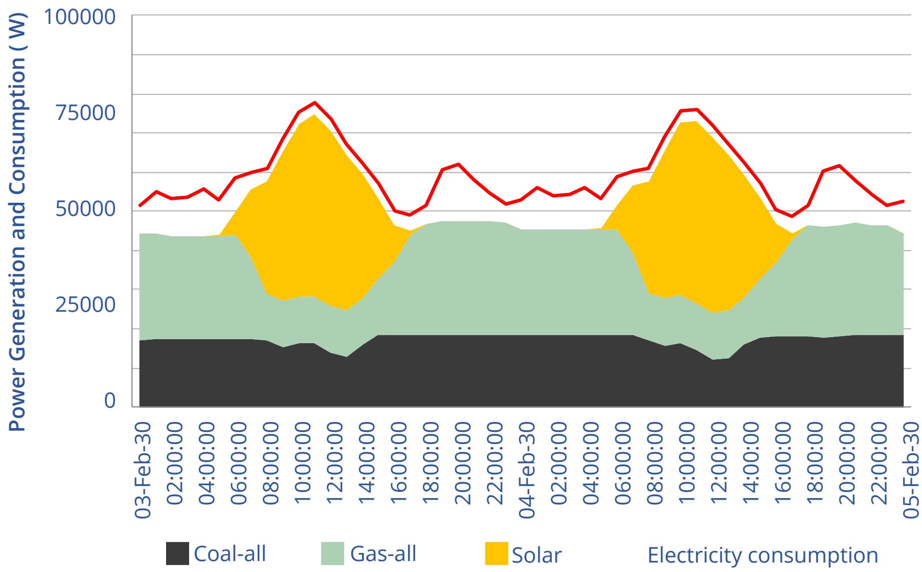


Figure 26. Power generation from CFPPs, GFPPs and solar PV plants and consumption within Java-Bali system during low solar irradiation in 2030

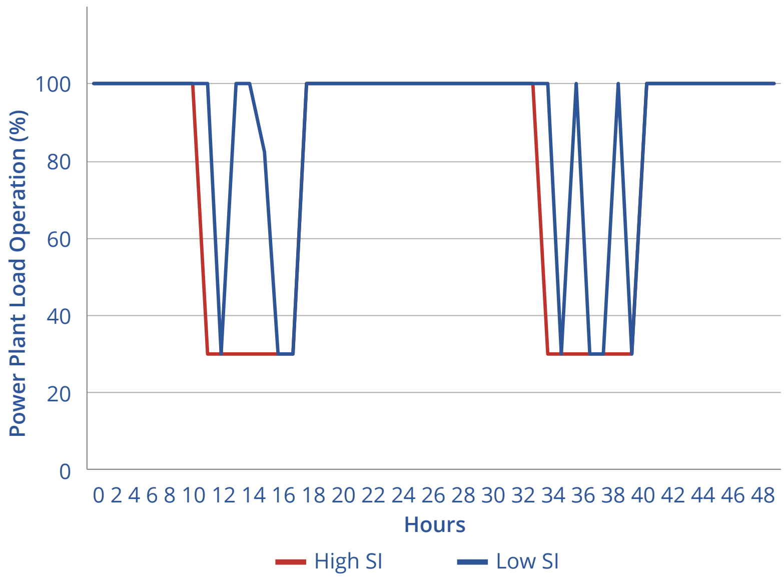


Figure 27. Typical 600 MW CFPP load operation in Java-Bali system during high (High SI) and low (Low SI) solar irradiances

Comparison of a typical 600 MW CFPP unit, unit B, operating within these solar irradiation conditions is presented in Figure 27. During the high solar irradiation, the unit could maintain its extended low-load operation, at 30%, for 6 hours before ramping back up to its full-load. The same holds for the next day's operation. On the other side, more rampings of the unit during the low solar irradiation can be observed from Figure 27. The unit stays at 30% load for only an hour within the peaking periods of solar PV power generation. The frequent rampings seen from the graph could have been due to the selection made by the simulated model, considering the age, the emission intensity of the power plant, and the load balancing within the system.

Sulawesi system - Similar to Sumatra, Sulawesi also has a variety of renewable sources, including solar, hydro, geothermal and wind, each with enough potential energy to serve the island's electricity needs. By 2030, 51.2% of generation is projected to be coming from tapping these renewable resources, followed by coal at 42.4% and gas at 6.4%. Furthermore, more than half of the renewable generation, ~61%, will come from the contribution of the variable ones, in which solar PV is still holding the majority share. Second to solar PV is hydro, contributing to 27.7% in the generation from renewable. Figure 28 and 29 reflects these proportions of share in the system generation mix during two solar irradiance scenarios. Regardless of the scenario, the solar PV generation reaches its peak generation between 05:00 and 17:00 each day. As presented in these figures, the peak demand is rightfully served by the inception of the solar PV generation, with the other generations reacting differently depending on the solar irradiance scenario. In the high solar irradiance scenario, Figure 28, other generations cumulatively ramp down their generation every time the solar PV generation is at its peak. The gas and coal are observed to be ramping down their cumulative load to be as low as ~17% and ~41%, respectively. While this is true for the high solar irradiance, the same trend is not observed in the low solar irradiance, Figure 29. Despite the inception of solar PV generation, other generations are relatively unaffected by it. In particular, coal is acting as base load, with almost no cycle of load rampings observed within 48 hours of operation. This, in turn, affects the operational behaviour of each CFPP unit within the system, particularly one that is considered in the analysis in this paper.

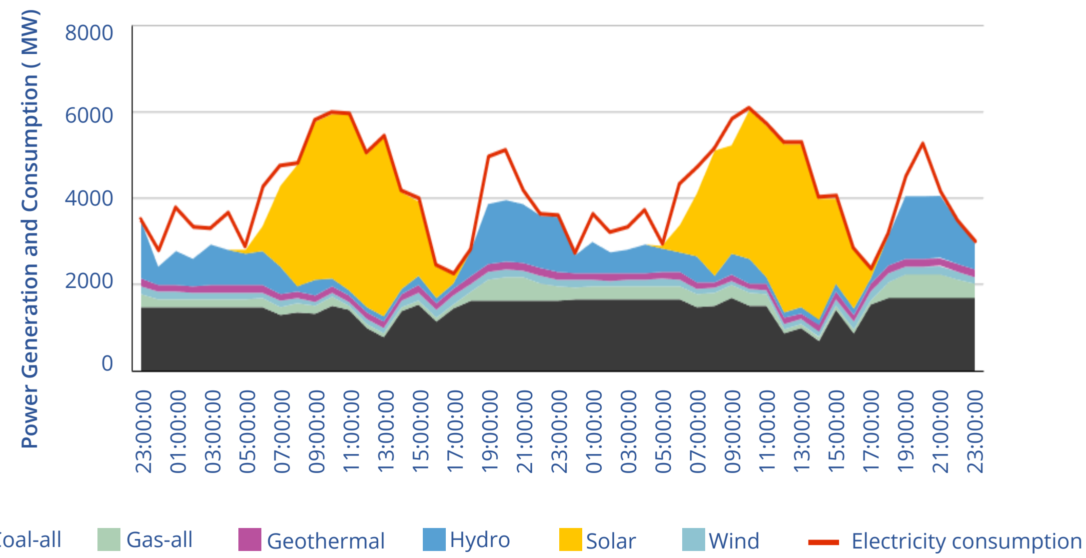


Figure 28. Power generation from CFPPs, GFPPs and solar PV plants and consumption within Sulawesi system during high solar irradiation in 2030

A typical CFPP unit with a capacity of 100 MW is acquired in the analysis of this paper, marked as unit C. It is a representable capacity, as the CFPP units within the Sulawesi system are predominantly below 300 MW, similar to the situation within the Sumatra system. Figure 30 depicts the unit plant load profile during two days operation. It can be seen that the unit is experiencing frequent rampings with a few hours spent at its minimum load, in this case 30%. These rampings coincide with the peaking period of solar PV generation, a response expected from a flexible CFPP. Notice that from the figure only one load profile is present, which in this case represents the high solar irradiation scenario (High SI). In the model, the unit does not operate during the low solar irradiation scenario as, timewise, it coincidentally falls within the period of the unit's scheduled retrofitting work. The work itself is assumed to take place in the first semester of 2030 with a duration of 6 months.

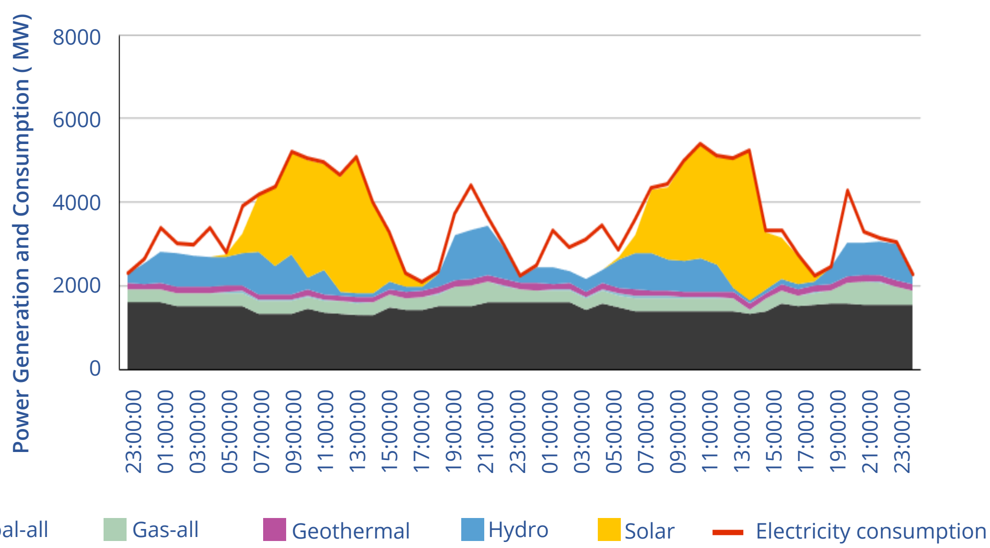


Figure 29. Power generation from CFPPs, GFPPs and solar PV plants and consumption within Sulawesi system during low solar irradiation in 2030

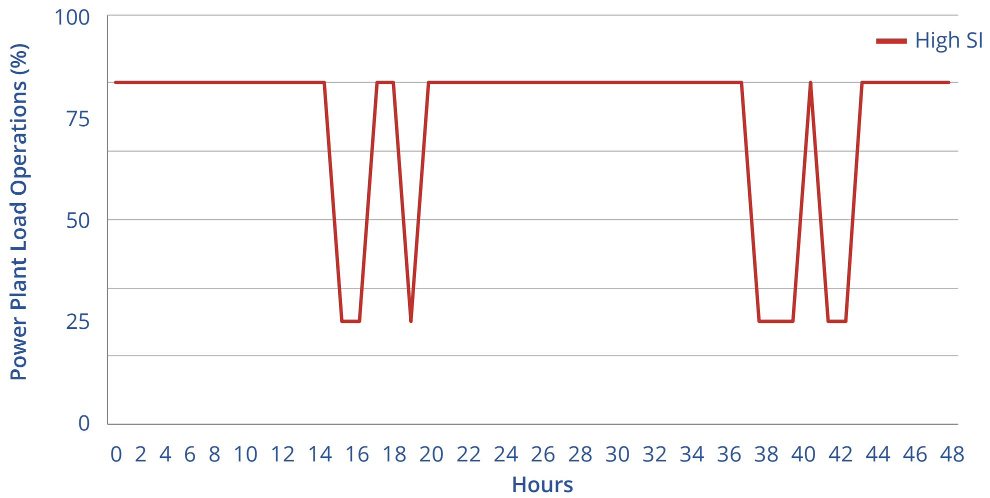


Figure 30. Typical 100 MW CFPP load operation in Sulawesi system at high (High SI) solar irradiance

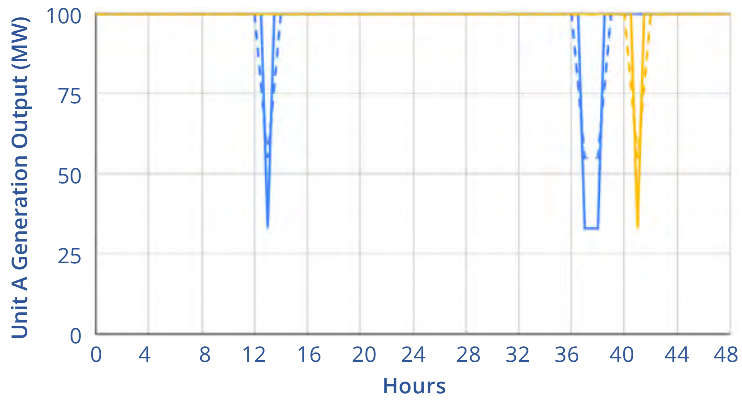


Figure 31. Unit A flexible scenarios

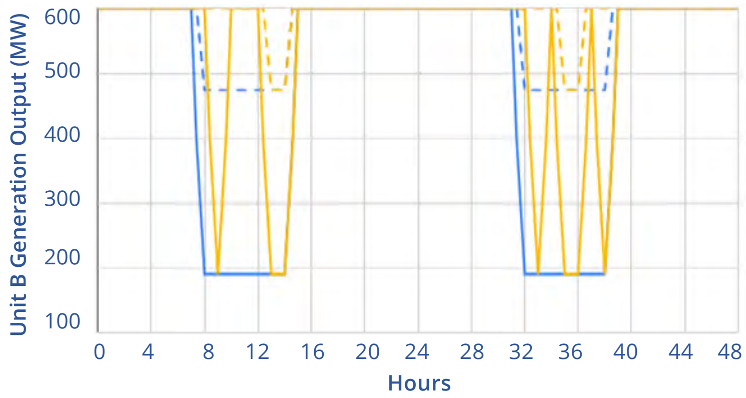


Figure 32. Unit B flexible scenarios

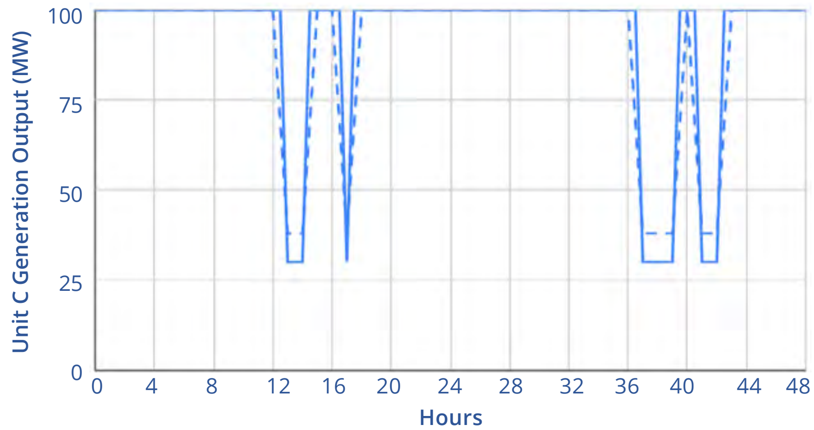


Figure 33. Unit C flexible scenarios

Hi_Post-retrofit   Hi_Pre-retrofit   Lo_Post-retrofit   Lo_Pre-retrofit

The generation profiles shown in Figure 24, 27 and 30 were employed in this study as the scenarios to assess the implications of flexible operation of CFPP. However, the minimum load used in this study will be close to 30% load, as this will be presented next.

Estimated Performance and Emissions of Flexible CFPP

Two solar irradiation cases were considered in the analysis of CFPP unit A and B, and a single case for unit C. These are all respectively presented in Figure 31-33.

The variations in the mode of flexible operation are subjected to each CFPP study case location and generation landscape within the Java-Bali, Sumatra and Sulawesi systems. Within each case depicted in these figures, the pre-retrofitted CFPP is also assumed to undergo the operational patterns: ramping up/down to its pre-retrofitted minimum load level (dashed line). Hence, the pre-retrofitted minimum load level is higher than the retrofitted one (solid line). Estimated performance and emissions of each CFPP study case are calculated based on these scenarios. Table 9 shows the reduced minimum load, i.e. close to 30% from previously 55% for unit A, 79% for unit B and 38% for unit C (see Table 8), as indicated in load operation profiles in Figure 24, 27 and 30, and its estimated net generation efficiency of each CFPP study case. The reduced efficiencies come from gradually deducting the former minimum load's efficiency presented in Table 8, namely 21.73% for unit A, 35.83% for unit B and 25.44% for unit C, with the estimated efficiency reduction range, i.e. 2-5% for every 20% point reduction of the load (see Figure 22), until the associated minimum load gets closer to 30%. Therefore, unit A, B and C's efficiencies are reduced by 4-10%, 6-15% and 2-5%, respectively, to get to their new minimum loads, as seen in Table 9. The lower end of the efficiency reduction range can be considered as the most optimistic outcome, whilst the higher end is considered to be the opposite. With regards to the ramping rate, this study assumed that the retrofitting package increases the rate by two-folds, hence cutting down the ramping up or down time in each CFPP study case by half.

Parameters	Unit A	Unit B	Unit C
Minimum load reduction (%)	22	48	8
Minimum load after retrofit (%)	33	31.6	29.82
Minimum load after retrofit (MW)	33	189.6	30.2
Ramp rates (%/min)	2	1.14	2
Estimated net generation efficiency at minimum load after retrofit (%)	11.73 - 17.73	20.83 - 29.83	20.44 - 23.44

Table 9. CFPP study cases minimum load and ramp rates after retrofit and its respecting net generation efficiency

Finally, the results of these scenarios on each CFPP unit are presented in Table 10 and 11. In Table 10, the CO_2 emission per generation (gramCO_2/kWhel) changes of each CFPP unit during high and low solar irradiation are presented in percentages. The positive sign seen in the table indicates that the new retrofitted CFPP emissions level is higher than the pre-retrofitted CFPP. Meanwhile, the negative sign indicates the opposite effect on the emission change. The results are also presented in range due to the assumed efficiency reduction range mentioned earlier.

The results presented in Table 10 are clearly indicating that the retrofitted CFPPs produce higher emissions than the pre-retrofitted ones, despite operating flexibly at lower minimum load, except for unit C. At its most optimistic efficiency reduction, i.e. 23.44%, the unit sees lower emissions than its pre-retrofitted condition during the high solar irradiation case, hence the -0.19%. Even at the unit's worst efficiency reduction, i.e. 20.44%, the emissions change is still relatively better than other units within the same situation, i.e. +0.73% compared to +1.15% for unit A and +7.51% for unit B. Sure enough, the post-retrofitted unit B displays the highest emission change during both solar irradiation cases, occuring at the unit worst reduced minimum load efficiency, i.e. 20.83%. At its most optimistic efficiency reduction, i.e. 29.83%, the emission change is better by being only slightly higher than the pre-retrofitted unit, 1.23% during the high solar irradiation and 0.85% for the low one. Under a different flexible scenario, unit A's emission change is observed to be lower than unit B. The unit has undergone a number of rampings, particularly during the high solar irradiation, and, yet, the operation impacts the emission change by only a few percentages, rated at 0.21% for the most optimistic efficiency. Lower emission change is observed from the unit during the low solar irradiation, as it experiences only a single cycle of ramping. The positive changes in the CO_2 emissions exhibited by unit A and B boils down to the already low net efficiency at full load, namely unit A at 23% and unit B at 36.55%. Hence, improving the units' efficiency at full load may cause a domino effect on the efficiency at lower loads, which in turn reduces the CO_2 emission, as demonstrated by unit C.

CO_2 Emissions Change	Unit A	Unit B	Unit C
High solar irradiation	(+0.21%) - (+1.15%)	(+1.54%) - (+7.85%)	(-0.19%) - (+0.73%)
Low solar irradiation	(+0.04%) - (+0.26%)	(+1.08%) - (+3.45%)	-

Table 10. Estimated emissions change from the considered scenarios at Unit A, B and C

As can also be observed from Table 10, emissions change during the low solar irradiation are generally lower than during the high one, despite the higher electric generation and emissions as the CFPPs are deployed to fill in the gap created by lower solar PV-based electricity generation. The situation is particularly observed in unit A and B, as unit C is not in operation during the low solar irradiation. Close examination on these units' mode of operation reveals that the lower emission changes may have been caused by the period of time spent by each unit at its respecting lower minimum load, i.e. 33% for unit A and 31.60% for unit B. As depicted in Figure 31 and 32, each unit is operated at its minimum load for less than 3 hours during the low solar irradiation. During the high solar irradiation, in which the demand can be met with the electricity generated from solar PV plants, and other renewables in the case of the Sumatra system, each unit spent more operating hours at its minimum load. Therefore, the increased amount of time a unit spent operating within its minimum load could lead to an increase in the emissions level.

In Table 11, the absolute values of the emissions from the retrofitted units are actually lower than the pre-retrofitted ones, particularly in unit B. This is not the case with unit A and C as the flexible operation adopts a different scenario, which may have caused the generation to be slightly higher in the post-retrofitted than in the pre-retrofitted. Apart from lowering the minimum load, the retrofit is assumed to improve the ramping rates, allowing these units to operate at their full load slightly longer than the units' pre-retrofitted operation. Consequently, the CO_2 for the retrofitted unit is a few degrees higher than the pre-retrofitted one. In terms of the CO_2 emissions per generation, unit B is observed to be the lowest amongst the considered units, albeit the 600 MW capacity. Other units, i.e. unit A and C, are observed to be higher than unit B, with unit A to be the highest, ranging between 1,378.68 and 1,383.54 gramCO_2/kWhel. From here, it can be understood that large capacity CFPP, in this case 600 MW, with high efficiency, i.e. >36%, will indeed produce low emissions compared to its 100 MW peer, which generally possesses lower efficiency, in a typical range of 23%-30%. Nevertheless, unit B's low absolute value of the metric is not reverberated in the change of the metric itself, where the retrofitted unit is presented to be higher than pre-retrofitted one, which also holds true for unit A, as presented in Table 10.

Unlike in unit C, despite the higher CO_2 emissions per generation than in unit B, the change is towards the negative side, meaning the retrofitting has reduced the unit's CO_2 emissions per generation, i.e. from 1,077.14 to 1075.09 gramCO_2/kWhel. The positive change in the metric presented by unit A and B indicates that the unit consumes more coal to generate electricity at its lower minimum load, again due to the poor net efficiency at the associated load. The poor performance could be associated with the ages of these units that are close to the end of their operational lifetime. Clearly, unit A and B are both within the 21-25 age group, whilst unit C is within the 0-5 age group (see Table 8). As the ageing units, i.e. unit A and B, are approaching their limits, the components of each unit's subsystems may have been degraded. Operating them flexibly is shown to just worsen the performance of the units, an important point of consideration in shortlisting CFPP units for flexibilisation.

Parameters	Solar Irradiation	Unit A		Unit B		Unit C	
		Pre	Post	Pre	Post	Pre	Post
Efficiency (%)	-	0.2173	0.1773	0.3583	0.2983	0.2544	0.2344
Electric generation (MWh_{el})	High	4,665	4,666	27,074	23,054	4,304	4,380
	Low	4,755	4,767	28,271	25,722	-	-
CO_2 emissions (tonnes)	High	6,440	6,456	23,797	20,577	4,636	4,709
	Low	6,556	6,574	24,546	22,573	-	-
CO_2 emissions per generation ($gramCO_2/kWh_{el}$)	High	1380.59	1383.54	878.98	892.55	1,077.14	1,075.09
	Low	1378.68	1379.16	868.24	877.59	-	-

Table 11. Performance and emissions from the considered scenarios at Unit A and B before (pre) and after (post) retrofit for the most optimistic efficiency reduction

5.2.2. Cost and Benefit Analyses

Cost to Retrofit CFPP

In this part of the paper, the cost to retrofit a CFPP is calculated with reference to Germany and India experience. The retrofit investment cost per unit of generating capacity (MW) is presented in Table 12. A stark difference in the cost is clearly observed from the table. It should be noted that most of the power plants in Germany, as mentioned earlier, have their ages ranged between 25 to 37 years old. Therefore, the retrofit type that is mostly implemented there is plant modernization. In India, the flexibilisation pilot project so far only included young power plants. This, in turn, affects the retrofit type, which is more on enhancing, or rather pushing close to the design limits, the power plants capability through optimization procedure and minor addition in the condition monitoring.

Country	CFPPs Age Range	Retrofit Package	Retrofit Period	Investment Cost
Germany	25 - 37 years	Plant rejuvenation and modernization	2.5 to 12 months	$132k - $405k/MW
India	4 - 8 years	Start-up optimization and condition monitoring equipments	4 to 12 months	$2,400 - $5,400/MW

Table 12. Investment cost to retrofit a CFPP unit based on Germany and India experiences, as indicated in Table 7

The units considered in this study, which are classified within the 21-25 years age group, could be opted for the first retrofit package, hence Germany's experience. With the information in Table 8, the retrofitting of the units will cost $13.2 million - $40.5 million for unit A and $79.2 million - $243 million for unit B, respectively. As laid out in Table 7, the large sum of investments is the results of adding auxiliary power plants for repowering purposes, e.g. gas turbines as in the case of Weisweiler power plant, and replacement of ageing components, e.g. steam turbine stages as in the case of Zolling power plant. These retrofitting options may not be necessary for unit A and B. In this analysis, the cost estimation is solely based on the age of the power plant, whereas there are actually a number of considerations to arrive at a plant-by-plant retrofit investment cost. These include the plant status and its level of automation, the availability of incentives and business models that reward flexible operation, and the power plant contractual obligations (VGB, 2018).

As shown previously, Indonesia's CFPP units (PLN, IPP-owned, and PPU combined) are dominated by young power plants. As presented in Figure 19, Indonesian CFPP units are observed to be under 16 years old. Within this range, the 100 MW capacity class comes first, followed by the 101 - 300 MW and 301 MW and 600 MW capacity classes. In this case, India's experience could give a reasonable estimation for the retrofit investment cost. Ignoring the age group and laser-focusing on the capacity of unit A and C, the cost would be $240,000 - $540,000 for the 100 MW and $1.44 million - $3.24 million for the 600 MW. In its report, VGB, an international technical association for the generation and storage of electricity and heat based in Germany, provided an estimated cost of investment to lower CFPP's minimum load down to a range between 20% and 40% of nominal capacity (Pnom)(VGB, 2018), which is around $5,000 - $15,000/MW. Hence, using the same estimate for unit A and B, which in this study has been estimated to run at the minimum load of 33% and 31.60%, respectively, gives $500,000 - $1.5 million for unit A and $3 million - $9 million for unit B. Table 13 summarises the estimates indicated within this section.

References for retrofit cost of investment	Unit A & C	Unit B	Note
Germany experience	$13.2 mil. - $40.5 mil.	$79.2 mil. - $243 mil.	The estimate comes for the country experiences in rejuvenating and modernising its old and ageing power plants; the cost covers the replacement of critical components, such as steam turbine blades and plant control system
India experience-1	$240,000 - $540,000	$1.44 mil. - $3.24 mil.	The estimation is based on a preliminary study that identifies the requirement to make a CFPP flexible; the study was carried out prior to the start of the pilot projects
India experience-2	n/a	n/a	During the trial run, the units were operated flexible simply by changing its operational procedure; Despite the null requirement for investment cost, there may, however, be fees for consultant and retraining operators, which could cost lower than the previous experience
VGB estimate	$500,000 - $1.5 mil.	$3 mil. - $9 mil.	The cost to achieve minimum load between 20% and 40%

Table 13. Cost estimates for CFPP flexibilisation in Indonesia

Additional Cost to Run Flexible Operation on CFPP

Apart from the investment cost, running flexible operation on CFPP would also incur additional costs in the operational expenditure. As the power plant undergoes cyclic operation, i.e. with more frequent ramp-up/down from its minimum load and/or shutdown/startup, the cost must cover the risk of component failure and shorten lifetime, which in the perspective of power plant operation considered as losses.

Table 14 shows the estimated running cost of CFPP flexible operation in India for two typical capacity classes, namely 200/210 MW and 500 MW. Indeed, the capacity classes are different from the units considered in this study. However, the dataset is the only data available in the public domain and, therefore, the outcomes presented here will be treated as the highest and lowest estimates of unit A and C, respectively. The table also included the estimated cycling cost[30] components for unit A and C before and after the retrofit. There are three components to be considered in such operations. The first component is associated with the cost due to heat rate degradation. As the load goes lower, the heat rate of the power plant is getting larger, as shown previously, thus impacting the efficiency which in turn increases the coal consumption. This is also applied to the start-up operation, depending on how frequent, whether it is daily or weekly. Another component is related to additional operation and maintenance (O&M) cost from operating beyond designed minimum

[30] It is defined as the cost incurred from changing the power out of a power plant by means of ramping to/from its minimum load and switching (starting up and shutting down)

load and with frequent start-up/shutdown. This is particularly incurred for an old CFPP unit with no previous history of R&M. The last component is specifically applied to the start-up/shutdown operation, namely start-up oil cost. The more frequent the start-up is carried out, the more the start-up oil, which is generally High Speed Diesel (HSD), is required. This eventually will cause an increase in the CFPP total cost, which is reflected in the table.

Load (%)	200/210 MW Unit				500 MW Unit			
	Add. cost due to increasing Heat Rate	Add. O&M Cost	Start-up oil cost	Total	Add. cost due to increasing Heat Rate	Add. O&M Cost	Start-up oil cost	Total
90	0	0	0	0	0.15	0	0	0.15
80	0	0	0	0	0.45	0	0	0.45
79*	-				0.46	0.94	0	1.4
70	0.27	0.44	0	0.71	0.89	0.94	0	1.83
60	0.99	0.44	0	1.43	1.7	0.94	0	2.64
55*	1.46	0.44	0	1.9	-			
50	2	0.44	0	2.44	2.7	0.94	0	3.64
40	3.1	0.44	0	3.54	3.7	0.94	0	4.64
33**	4.17	0.44	0	4.61	-			
31.6**	-				4.78	0.94	0	5.72
30	4.6	0.44	0	5.04	5	0.94	0	5.94
Weekly start	3.1	8	2	13.1	3.7	9.2	1.4	14.3
Daily start	0.99	59	15	74.99	1.7	70	9.9	81.6

Table 14. Running cost, converted to $/MWh, of flexible operation in CFPP (India's experience) (Powerline, 2019)

With the same profiles shown in Figure 31-33, the cycling cost of these power plants for the period of time indicated in the figures can be estimated, presented in Table 15. The calculations are limited to the most optimistic efficiency reduction.

Cycling cost change	Unit A	Unit B	Unit C
High solar irradiation	21.64%	63.81%	-23.97%
Low solar irradiation	4.38%	575.47%	-

Table 15. Cycling cost changes of unit A and B relative to the pre-retrofitted condition

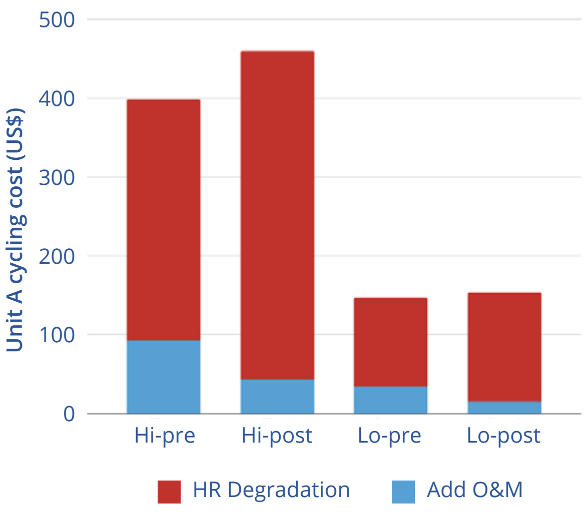


Figure 34. Unit A cycling cost breakdown

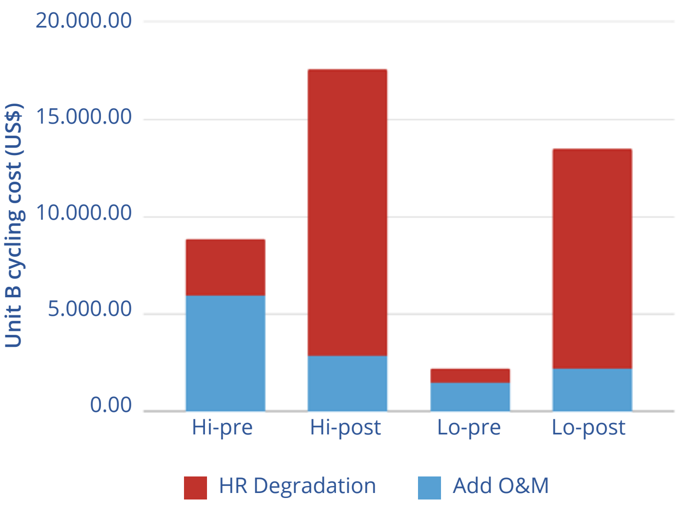


Figure 35. Unit B cycling cost breakdown

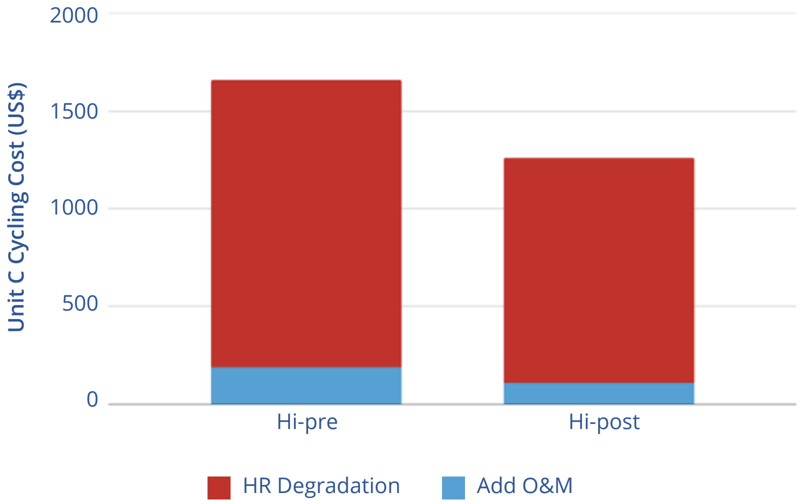


Figure 36. Unit C cycling cost breakdown

A breakdown cost before and after the retrofit for the two solar irradiation cases , a single solar irradiation case for unit C, are subsequently provided in Figure 34-36. The positive sign seen in Table 15 indicates the increasing cycling cost relative to the same metric prior to the retrofit. Weekly or daily starts are not considered in this analysis as the scenarios explained earlier do not include start-up/shutdown operations.

All cases are uniformly showing an increase in the cycling cost when operated at lower minimum load, except for unit C. As explained earlier, the retrofitting in unit C has resulted in the unit operating at full load longer than at its pre-retrofitted condition due to the unit's improved ramping rates, enabling the unit to have better load following capability. Operating more hours in the full load means the unit is operating more within the region where no cycling cost incurred, hence the lower cycling cost. On the contrary, the highest increase is observed for unit B during the low solar irradiation. This is understandably due to the frequent rampings as the solar PV generation may not be sufficient to meet the demand during that period of time, see Figure 32. Apart from lowering the minimum load, the retrofit is assumed to also increase the ramping rates of the unit. The unit previously required around 2 hours to ramp-down to/ramp-up from its designed minimum load at 79%. The retrofitting is then assumed to have increased the rate, halving the time required to go to and from lower minimum load at 31.60%. This in turn increased its capability to operate with more rampings as a response to the change in the grid, which happens within the same period of time as in the pre-retrofitted condition. Compared to unit B and C, unit A does not seem to have the cycling cost enormous jump for its pre-retrofitted operation. The main cause is of course due to the operational modes of the unit itself. Observing back Figure 31, it is clear that the unit operational mode still resembles a typical base load generation, with less ramping cycles and the amount of hours spent on the minimum load.

On the cost component-level, the cost due to HR increase could be observed to be driving the cycling cost for scenarios in all units. This is clearly observed from unit B, as the unit is experiencing the largest drop in its minimum load, from 79% to 31.60%, compared to unit A, which has gone down only from 55% to 33%, and unit C, which has gone down by 8% to 30% in addition to the lower cycling cost than its pre-retrofitted condition. Unit C, in particular, sees the unit's HR increase cost reduced due to less hours spent in ramping up and down, while at the same the cost component is still being the main driver in the unit's cycling cost. Nevertheless, the outcome here should be taken with caution as the estimated costs are limited to two days' operation. A complete projected operational profile should be further considered to have a yearly estimate of the cost. One thing for sure is that, along with the investment cost required to retrofit these units, the cycling cost may increase Levelised Cost of Electricity (LCOE) due to the units low utilisation.

Estimation on Flexible CFPP LCOE

In this part of cost analysis, the Levelised Cost of Electricity (LCOE) from the flexible CFPP units considered is estimated. Table 16 provides the main indicators used in the calculation. Indicators, such as investment and variable operating costs, efficiency, Capacity Factor (CF) and CO_2 emissions factor, have been adjusted relative to the typical subcritical CFPP unit to reflect the previous analyses on performance and prior discussions on investment and cycling costs of unit A, B and C, hence the low-high range in the flexible subcritical 100 MW and 600 MW. Included in the table is the Open Cycle Gas Turbine (OCGT) and Combined Cycle Gas Turbine (CCGT) indicators for the LCOE estimation.

Financial and Technical Indicators	OCGT	CCGT	Subcritical	Flexible Subcritical 100 MW		Flexible Subcritical 600 MW	
	Typical	Typical	Typical	Low	High	Low	High
Investment cost ($/kW)	770	690	1650	1652	2055	1652	2055
Fix operating cost ($/kW/year)	23.2	23.5	45.3				
Variable operating cost ($/MWh$_{el}$)	0.11	2.3	0.13	0.45	1.5	0.66	1.95
Fuel cost ($/MWh$_{therm}$)	23.9		9.53				
CO_2-Cost($/t$CO_2$)	10						
Technical lifetime of plant (years)	25	25	30				
Efficiency (%)	33	56	34	23	30.77	45	36.55
Capacity Factor (%)	35	35	7	74.59	46.5	75	60.98
CO_2 Emission factor (tCO_2/GWh$_{th}$)	540	404	1200	1379.16	1075.09	1200	892.55

Table 16. Main indicators for Gas Turbine (GT) power plants, subcritical CFPP and flexible subcritical CFPP LCOE estimation

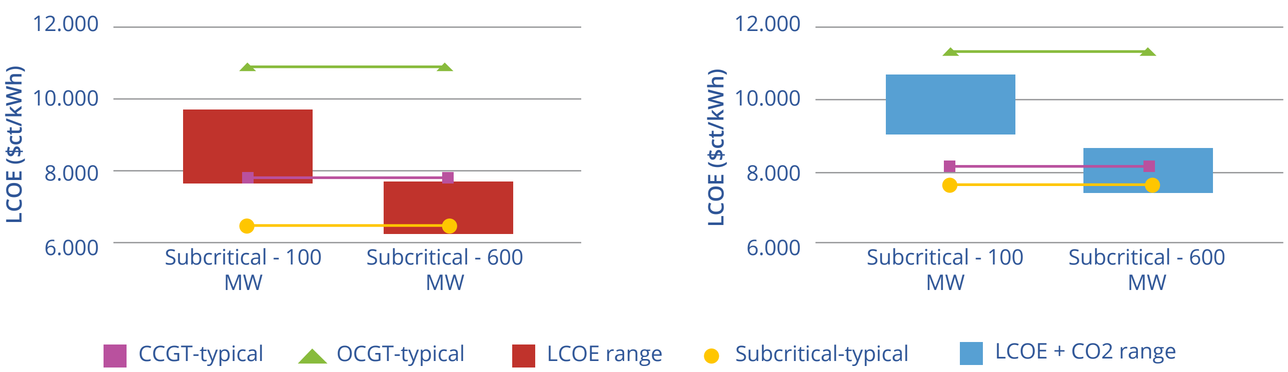


Figure 37. Flexible CFPP LCOE estimation for two subcritical units with different capacity class, i.e. 100 MW and 600 MW: **top** - LCOE, **bottom** - LCOE with CO_2 price

These power plants are known for their embedded flexible capabilities and, therefore, their estimated LCOE will be an on-par comparison against the flexible subcritical ones.

There are several approaches in estimating the LCOE. One that is considered quite simple and allows for quick recalculation and comparison of the sensitivity of different indicators to the outcomes is the Annuity Method (IESR, 2019). IESR has developed a LCOE estimation tool for power plants in Indonesia available for public use. The tool itself is based on a LCOE calculation model constructed by Agora Energiwiende. Using the tool, the LCOE of the flexible subcritical CFPP units are calculated and the outcomes are presented in Figure 37. The top figure is the estimation for the LCOE alone, whilst the bottom one includes the typical pricing for CO_2 emissions in Indonesia.

As clearly observed in Figure 37, the typical OCGT sets the highest bar of the LCOE amongst other power plants, even the CFPP ones. The condition remains the same even when the price of the CO_2 is included in the calculation. One obvious reason for this must be due to the price of the natural gas that is two-fold higher than the price of coal used in the typical CFPP. The flexible subcritical 100 MW CFPP unit comes second in both figures, consistently listed right after the typical OCGT. The highest end of the unit's range is highly influenced by the low CF and high variable operating and investment costs. The latter is a direct implication of retrofitting the CFPP unit, as well as operating it flexibly. The lowest range of the unit coincides with the LCOE of typical CCGT. This is true for the LCOE exclusive of the CO_2 price. When included, the lowest range of the CFPP unit is higher than the typical CCGT.

The LCOE of the other flexible subcritical CFPP unit, i.e. the 600 MW, has even lower range than the 100 MW CFPP unit, including one that accounts for the CO_2 price. Higher efficiencies and utilisation of the 600 MW unit has undoubtedly resulted in such circumstances. The LCOE of the unit is also comparable to the typical CCGT, with and without the CO_2 price included. From these observations, it can be concluded that the flexible CFPP units can serve as alternatives to the gas-based power plants as load follower in the system, with the 600 MW unit as a promising candidate for the role.

Benefits from CFPP Flexible Operation

Having discussed the cost of CFPP flexible operation, the benefits that may arise from such an operation are touched next. The benefits are weighed with regards to the power system, e.g. the renewables curtailment, and plant-level point of views. The discussion on the benefits below is not exhaustive and will only be carried out qualitatively based on available studies, either by external bodies or by IESR itself.

A study carried out by NREL under USAID Greening the Grid (GTG) programme in India stipulates that maintaining the CFPPs' minimum load at 70% during its operation would result in 3.7% renewables curtailment to ensure grid stability (USAID & Ministry of Power, India, 2021). Furthermore, the study also suggests that a curtailment reduction by 0.76% is obtained from operating the CFPPs at 40% minimum load. The renewables curtailment has been understood to increase generation cost. Therefore, reducing the curtailment will make renewables remain economically competitive compared to their thermal-based generation.

Within the Indonesia context, the Java-Bali system, particularly, will experience around 1.3 TWh of renewables curtailment in 2030, as reported in the recent IESR study (IESR, 2021). This is around 0.24% of the total generation from all operating power plants that year. Of the figure, 15 GWh comes from curtailing the solar PV plants. The Sumatra system also experiences renewables curtailment in 2030 at 1.05%, slightly higher than in the Java-Bali system. No curtailment is projected on the solar PV plants in the Sumatra system. Instead, the curtailment in the Sumatra system reduces the generation from the hydro and geothermal power plants. Each power plant is respectively being curtailed by 499 GWh and 849 GWh.

In terms of the total generation, the curtailment rate for each power plant is then estimated to be 0.35% for the hydro and 0.66% for the geothermal. With the renewables curtailment at 1.05%, the total curtailment rate from both power plants is clearly dominating the Sumatra system curtailment. The Sulawesi system is not any different than the other systems. Renewables are expected to be curtailed by 1.71% of the total generation in 2030, with solar PV, hydro and geothermal power plants topping the list of curtailed renewables. The solar PV is projected for being with least curtailment at 2 GWh, followed by the geothermal at 63 GWh. The largest curtailment is expected to happen on the hydro power plant, curtailed by 467 GWh or around 1.5% of the total generation in 2030. In retrospect, the curtailment rates projected for the systems considered in this study are still generally insignificant to cause an increase in the generation cost of the renewables themselves. Moreover, the small curtailment could have been made possible by the retrofitting programme for the 30% minimum load on all CFPPs within each system that has reached its completion by 2030.

Start-up cost	Unit A & C	Unit B
High	Rp 354,000,000	Rp 2,120,000,000
Low	Rp 265,000,000	Rp 1,590,000,000

Table 17. Start-up cost of unit A and B categorised according to the range of price for the industrial-type HSD

The majority of this study has been on the discussion of extending down the minimum load, as well as increasing the ramping rates. As touched earlier, enabling the CFPP to operate at low minimum load would avert the need to start-up/shutdown the CFPP. Therefore, at times when the renewables, particularly the solar, are at their peaks, the CFPPs can simply turn its load down. Furthermore, it is understood that not only the frequent start-up/shutdown may affect CFPP components lifetime, but it also causes a significant increase in the O&M cost, as reflected in Table 10. A typical 600 MW unit, such as unit B, may require an average of 150,000 litre of High Speed Diesel (HSD) during its start-up. A smaller unit, 100 MW of unit A for instance, would consume less fuel during its start-up, namely around 25,000 litre. Recent pricing for the industrial-type HSD ranges between IDR 10,600 and IDR 14,150 per litre (Megah Anugrah Energi, 2022).

Table 17 provides the estimated start-up cost for each unit. These large sums of money required are yet to be scaled up with the amount of start-up in a year of operation of the power plant. Even so, as reflected from Table 16, each start-up, be it due to forced or planned outage, will definitely result in the cost swelling of the O&M. Therefore, lowering CFPP minimum load may help the operator to make a saving on their O&M costs as it would effectively reduce the number of unnecessary start-up outside the forced or planned outage.

Another benefit from operating CFPP flexibly is regarding its potential contribution in reducing system cost. Kubik et al. (2015) were numerically assessing a variety of different flexible CFPP scenarios in Northern Ireland intended for wind curtailment reduction. They found out that by making the CFPP to run flexibly, in their case through operating the boiler on one mill assisted with continual oil fuel firing, there's a potential saving in the system cost of over £1 million, as well as CO_2 emissions and, most importantly, wind curtailment reduction. The system cost saving itself is largely coming from the reduced system curtailment cost which is a function of the System Marginal Price (SMP)[31] and the wind curtailment reduction. In another line of work, Garðarsdóttir et al. (2018) indicated that flexible CFPP is economically competitive against Natural Gas Combined Cycle (NGCC) in scenarios where the renewables generation share must strictly adhere to 65% of the mix and the CFPP has a high utilisation factor[32]. In that sense, the flexible CFPP is costing less, in terms of annual operating cost, than the NGCC for a relatively similar flexibility which in turn resulted in the system cost reduction.

The finding is also reverberated in the work by Ding et al. (2021) that evaluate the economic and environmental impact of flexibilisation of the CFPP in Jiangsu's power system. Through their modelling, they have identified at least three main causes of the flexible CFPP-incited system cost reduction. The first cause is due to less renewables curtailment that leads to their higher penetration into the system, enabled by operating the CFPP flexibly. This is a particularly similar finding as in the first reference cited earlier. The second cause comes from the cost avoidance of utilising other expensive forms of technology to enable flexibility in the system, including energy storage, e.g. battery, and natural gas-fired power plants.

Lastly, the cause of the reduction is specifically regarding the utilisation of different CFPP capacity classes. Through CFPP flexibilisation, large and efficient CFPP units are allowed to run at its full capacity, hence reducing the overall cost. Whilst a small CFPP unit operates more flexibly, it will then produce less electricity than the large CFPP unit.

[31] System Marginal Price is essentially electricity price determined by electricity demand from a pool of different power generation technologies arranged according to merit order scheme, i.e. starting from the technology with the lowest variable cost.
[32] The paper uses the term 'Full Load Hour' (FLH) to describe the level of plant utilisation.

5.3. Key Takeaways

The renewables will undoubtedly become the main sources to fulfil future energy demand, particularly in the power generation. The continued fall of the cost has driven many countries to allow further penetration of renewables in their power systems. Indonesia is no exception in this, having been blessed with abundant renewable resources, from geothermal to solar. The situation is worsen ultimately with the domination of the young units, aged below 10 years old, within the operating CFPPs fleet, built under the government-sponsored programmes to accelerate electricity infrastructure developments in the country. Forcing the renewable plants to be developed under such situations may lead to their curtailment, which in turn would increase the generation cost, making them less favourable economically. One way out of these situations is by making the CFPP units to operate flexibly that would shift their roles from a base load to simply a capacity reserve, hence allowing more renewables to be developed to supply the energy required in the systems instead.

The assumed retrofit considered in the analysis improves two criteria of flexible operation, namely minimum load and ramp-rates. With the retrofit, unit A, B and C are then assumed to be able to operate lower minimum load at 33%, 31.60% and 30%, respectively. The ramp rates for these units are also assumed to increase by two-folds. Imposing the new flexible criteria on the scenarios considered in the analysis has generally culminated in an increase in CO_2 emissions relative to the pre-retrofitted condition of each unit. Some findings from the analysis are:

- Reduction in efficiency due to lower minimum load is a major factor in increasing the emission.
- The poor efficiency at lower minimum load is tied up with the age of the units that are already close to their operational lifetime. As observed earlier, young power plants tend to be better in this sense.
- The period of time a CFPP unit spent on its new minimum load is shown to affect the emission level. Emission level is increasing if a CFPP unit spent long hours at the minimum load.

As with the cost, the flexibilisation of CFPP may require additional costs, as presented in the following:

- Capital cost to acquire necessary retrofit works ranges between $240,000 to $243 million. Nevertheless, there is a possibility of reducing the cost if the change is done only on the operational procedures, as demonstrated from India's experience.
- Additional O&M costs to run flexible operation, i.e. cycling cost, are generally increasing as each power plant operates at a lower minimum load. This is a compromise that must be weighed in while also considering the benefits from having a unit or group of units operating flexibly.
- The LCOE of flexible subcritical CFPP is higher than the typical subcritical CFPP. Nevertheless, the LCOE is still relatively below the OCGT and is actually comparable with the CCGT, making it a promising and cheaper candidate for load-follower role.

Operating a CFPP unit flexibly is not all doom and gloom. The following takeaways are some of the benefits that can be identified from having flexible CFFP:

- Flexible CFPP would provide more spaces for renewables to be utilised to the fullest, hence reducing their curtailment which would certainly increase the renewables cost of generation. Moreover, the low curtailment will maintain the generation cost of the renewables to remain competitive with other forms of generations, particularly the fossil-based ones.
- Another benefit is closely related to the CFPP operation itself. By lowering the minimum load, eventually frequent start-up/shutdown is no longer required at times of high generation from renewables. Apart from being emissions-intensed, frequent start-up/shutdown is also costly, due to the high pricing tag for industrial-type HSD in Indonesia.
- Flexibilisation of the existing CFPP fleet would reduce the system cost as the fleet serves as a cheaper alternative to other forms of storage and generation providing flexibility within the system, such as battery and the natural gas-fired power plants.

6

RECOMMENDATIONS

In a few years time, renewables are inevitably going to dominate the global power generation mix, spearheaded by solar and wind. Economies of scale have successfully driven the generation cost of solar and wind down, making them more competitive against conventional power plants, particularly CFPPs. Indonesia is no exception in this case. The generation cost of a newly built utility scale solar PV is expected to overtake newly built coal and gas-fired power plants by 2030. On the face of this exciting projection, Indonesia is faced with a situation in which almost 70% of its electric generation still comes from CFPP and most of the units are aged below 10 years. One way out of the conundrum is to operate some of the CFPP units flexibly, whilst at the same time ramping up the renewables capacity development.

Germany and India have already exemplified how a flexible operation can be carried out in a CFPP unit, exhaustively presented in Chapter 4. India, in particular, is actually still in its early phase of implementing it, a suitable example for Indonesia given its similar CFPP characteristics, especially on the age distribution. Apart from the technicality of flexible operation, these countries have shown suitable market structure and regulatory framework that incentivise operators to carry out such an operation. India has even prepared a compensation package for power plants, including CFPPs, that are operating below 55% load. As reflected from the analysis of Chapter 5, there are indeed compromises associated with emissions and cost in carrying out flexible operation in a CFPP unit. Particularly on the cost, be it the investment to retrofit or to cover the O&M of cyclic operation, a question arises on who will cover this and whether there is any change required to enable cost recovery from operating a CFPP unit flexibly within Indonesia's current regulation and market structure.

Based on the lesson learned and some findings from the analysis made in this paper, several recommendations are formulated below for relevant stakeholders to be considered. These recommendations are grouped in three categories, namely market, policy and contract, technicality and stakeholders engagement.

1. High Level Renewable Integration in The Power System Planning is a Requisite in The Energy Transition

Flexible operation in thermal power plants, particularly in CFPP, is merely a temporary measure to integrate more renewables in the system. This should not be taken as a way to sustain the use of CFPP in future power generations but as a transition measure of the power system to absorb variable renewables and energy storage. Going forward the CFPP will eventually be too costly to operate, either as base load or flexible generation, than renewables. Therefore, the flexibilisation must still adhere to the CFPP phasing out plan. Meaning that the flexible CFPP will be retired once the renewables supply can meet the demand and their intermittency can be mitigated by other flexible and clean alternatives, e.g. energy storage, hydrogen-powered gas turbine or demand response.

2. Market Design and Regulatory Framework

a. Regulation to Support Flexible Operation

A ministerial regulations and PLN directive order should be considered to allow existing and new power plants to run flexibly. The pilot phase must start with PLN's CFPP to avoid legal complexities with IPP contracts. In addition, Indonesia grid code, elaborated exhaustively in the Minister of MEMR regulation number 20/2020, needs to specify required flexible criteria, i.e. minimum load, ramp rates, start-up times. Rather than simply mentioning the requirement for ancillary services in a generic way, the grid code should include detailed information on some indicators for a variety of services, e.g. primary, secondary and tertiary.

The indicators particularly should include the time to response, reaction time and minimum offer on the capacity. How the service is procured and later paid for providing the service should also be regulated within the grid code.

b. Restructuring Power Purchasing Agreement (PPA) Contractual Terms to Shift CFPP Position from Being a Base Load Generation

On the contractual obligations, there needs to be a revision on Power Purchasing Agreement (PPA) that is currently still putting CFPP as base load. In the current PPA, the contract has a long tenor, generally 30 years, and a high degree of capacity factor (80% to 85%) stipulated in the take or pay clause. With increasing share of the renewables, the CFPP will eventually be shifted from its current position, resulting in lower operational utilisation. The PPA should then recognise, compensate and incentivise CFPP flexible operation, hence including a point on flexing the allowable heat rate, which corresponds to the lowest minimum load. With the current arrangement, there may be consequences, legally and financially, incurred from restructuring the PPA, particularly one that is related to the Take or Pay (ToP) scheme. Negotiation should consider lowering the scheme from 80% and encourage participants to enter ancillary services and capacity markets to cover the loss from lowered ToP scheme.

c. Market-based Mechanisms to Embrace High Share of Variable Renewables and Flexible Generation

As shown from the Germany and India experiences, to enable flexible operation for thermal-based power generation, particularly CFPPs, a less rigid one for Indonesia electricity market is required. This means moving away from the 'single buyer model' market to a wholesale market, with the market using day-ahead forecasting and/or real-time planning. This is especially important once the renewables, with particular the variable ones, share dominate the generation mix. It is also important to highlight that for the market to work the wholesale price should be determined through a bidding mechanism, in which all forms of power plant, including renewables, can participate. Hence, by doing so, the market will ensure each power plant is operated based on marginal costs and economic dispatch.

Considering the existing regulatory framework in Indonesia's electricity market, it might be difficult to move from its current form. Alternatively, there are certain markets that are encouraging CFPP to operate flexibly and could remain as a backdrop of the current market in Indonesia. These are capacity and ancillary services markets.

Despite the complexity of implementing the wholesale market, there is, however, a specific segment within the market dedicated to thermal power plants to compensate for their capacity availability to meet peak electricity demand. The market is specifically known as the capacity market. The income obtained from the market will guarantee basic income for the thermal power plants, including CFPP, as their revenues are reduced due to the reduced utilisation from high penetration of renewables.

Ancillary services market is another market framework that should be considered for implementation. This kind of market is expected to encourage power plant operators to willingly adjust their power as requested. As a consequence of this, CFPPs will be required to ramp-up/down accordingly. Financial mechanisms within the market will incentivise such an operation, as these power plants ensure the availability of positive reserves within the system.

In order for these markets to work, there should be an independent body formed to regulate newly-formed markets and their bidding mechanisms. This could be a government agency under the provision of MEMR, in the form of public sector undertaking. Another important prep for workable markets is the source of compensation for providing the capacity and ancillary service. One idea on this is to source the compensation for operators that are providing the services, i.e. capacity and/or ancillary services, by operating flexibly from other operators that are not providing the services. Say, an operator reduces its power plant load below a certain benchmark, e.g. 40%, for a fixed period of time. The cost borned from the operator from operating in such a circumstance is sold, in the form of credit, at a trading platform where other operators that are operating as base load generations will buy it. It can be thought of as a similar practice done in the currently trialled CO_2 emissions cap and trade for CFPP fleet in Indonesia.

3. Technicality

a. Identify CFPP Units in Indonesia for Flexible CFPP Pilot Projects

The government should identify CFPP units for pilot projects for several objectives. Based on the analyses laid out earlier, the pilot units should include units with:

i. Age <5 years old
ii. Subcritical technology
iii. Capacity between 100 MW and 600 MW
iv. As a starting point, units located in Sulawesi system

Following that, the next task is to suggest changes required to enable flexible CFPP. Moreover, it could also include recommendations for flexible operational procedures. Part of this could also be dedicated to the actual determination of these units' lowest minimum load. Next objective is to help the government and related stakeholders in the development compensation mechanism, as mentioned earlier. Lastly, plant-by-plant cost and benefit analysis would also be carried out in these pilot projects to determine the economic viability and identify initial capital investment and operational and maintenance expenses.

b. Consider Change in Operational Procedure in Operating CFPP Flexibly

Retrofitting a CFPP to operate flexibly, as in the experience from Germany, comes with several drawbacks. As reflected in the analysis, the investment cost is high and considering Indonesia's fiscal capacity, the approach seems unrealistic. Apart from that, the approach may result in prolonging CFPP lifetime and, hence utilisation, which would then contradict the initial intention in having flexible CFPP. Therefore, for Indonesia it is suggested that the approach to flexibilisation of the country's CFPP fleet is through operational procedure change, as in the experience from India with its trial run projects, combined with phase-down schedule as required to reach decarbonization/net-zero emission of the power sector.

4. Capacity Building for Policy Makers, Electricity Regulators and Operators to Run CFPP Flexibly

Capacity building with mentors from countries that are already implementing flexible operation in CFPP should also be considered. This can be in the form of a Focus Group Discussion (FGD). An example of such FGDs is the Indo-German Energy Forum (IGEF) in India. Some of the success stories of pilot projects for flexible CFPP were initiated from this form of partnership. The FGD will act as a platform for exchange experiences in flexible operation between stakeholders, as well as to identify further projects and training programmes in this context. Policy makers and electricity regulators participation are highly encouraged in such partnerships, hence providing the knowledge they needed for preparing market rules and, perhaps, reforming the existing power market. Another form of capacity building can be an exchange forum and short courses for operators.

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Appendices

A. Calculation Sample on India's Financial Compensation for Degraded SHR

Plant details	Unit Qty	Unit Size MCR	Plant Cap. (MW)		
	1	200	200		

Beneficiary details Name of beneficiary	A	B	C	D	Total
A - Contracted Capacity (%)	30	20	25	25	100
B - Contracted Capacity (MW) = A * plant capacity (MW)	60	40	50	50	200
C - Technical Minimum Load (MW) = 55% * B	33	22	27.5	27.5	110
D - Monthly Energy to meet 100% of their entitlement (MWh) = 720 hr (total amount of hours in a month) * B (MW)	43,200	28,800	36,000	36,000	144,000
E - Monthly Energy to meet 85% of their entitlement (MWh) = 85% * D	36,720	24,480	30,600	30,600	122,400
F - Requisitioned Energy in a Month (MWh), assumed	25,000	26,000	28,000	21,000	100,000
G - Un-requisitioned Energy below 85% of their entitlement (MWh) = E - F	11,720	-1,520	2,600	9,600	

Compensation charged to each beneficiary					
H - Monthly Effective Generation (MWh)	100,000				
I - Monthly Effective Capacity (MWh)	144,000				
J - Average Unit Loading (%) = H / I	69%				
K - Compensation amount (Rs), assumed	100,000				
L - Distribution Among Beneficiary (Rs) = K * (G/abs(GA+GC+GD))[33]	48,997	0	10,870	40,134	

Table A1. Simulation of the compensation mechanism for SHR & AE in a 200 MW power plant with multiple beneficiaries (Madhya Pradesh Electricity Regulatory Commission, 2020)

[33] Beneficiary B is excluded here due to the supplied energy is still above the admissible limit, i.e. defined by E

B. Further CFPP Units Characteristic in Indonesia

The following figures depict further CFPPs distribution, based on age group and generating capacity range, on each major island/region in Indonesia.

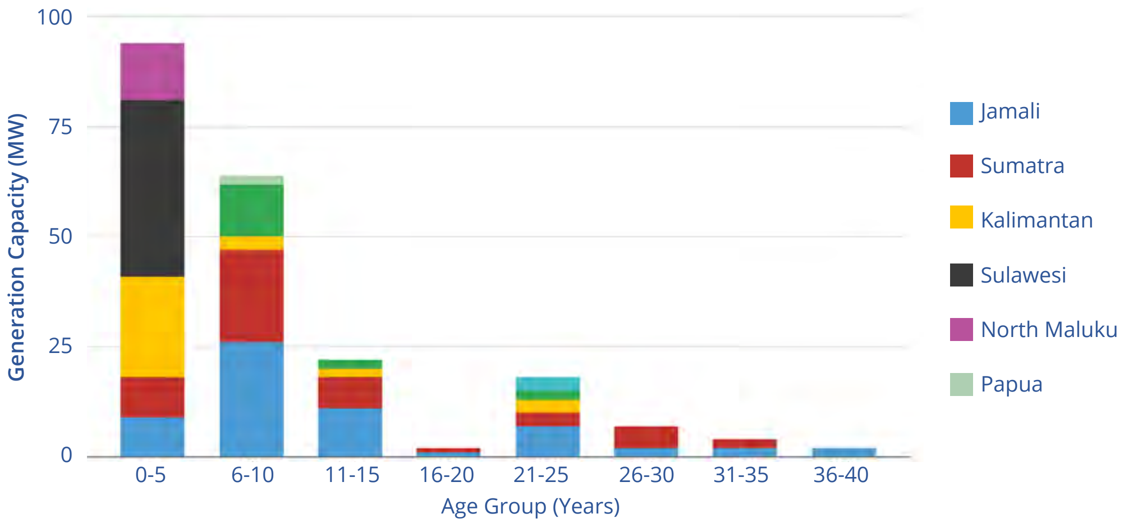

Figure A1. CFPPs distribution in major islands/regions, grouped according to age range

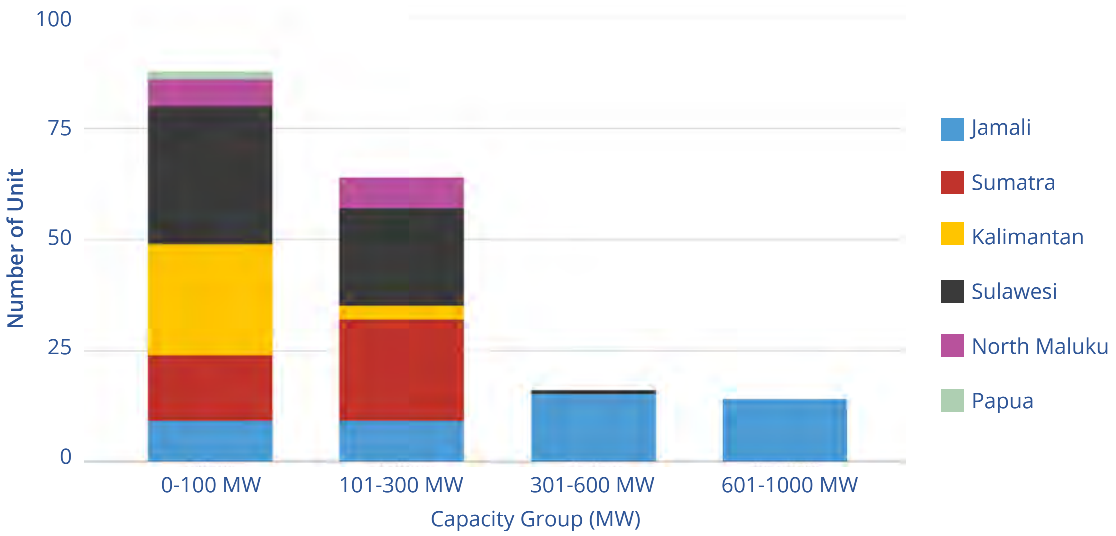

Figure A2. CFPPs distribution in major islands/regions, grouped according to generation capacity range

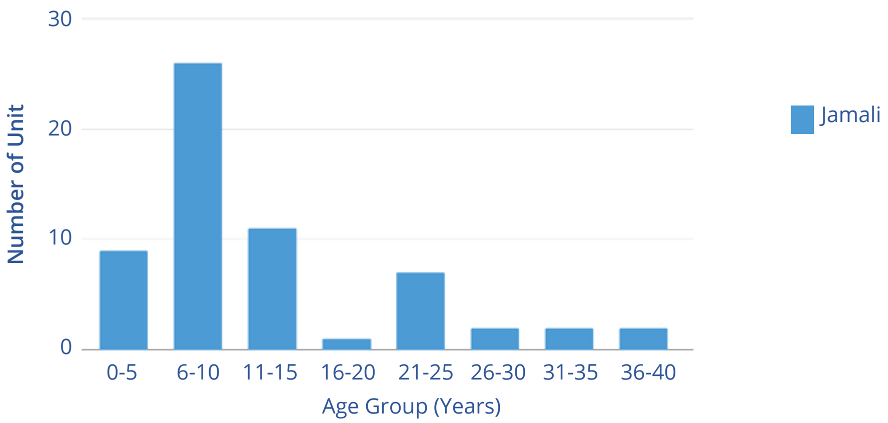

Figure A3. Number of CFPP units in Java-Madura-Bali (Jamali), grouped according to age range

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