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Ea Energy Analyses

Danish Energy Agency

Technology Data for the Indonesian Power Sector

Catalogue for Generation and Storage of Electricity

2024

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FOREWORD

This technology catalogue is a revised and updated version of the previous Indonesian technology catalogue of 2021. The new version of the catalogue has been prepared during 2023 by the Directorate General of Electricity in collaboration with the Danish Energy Agency and the Danish Embassy in Indonesia – supported closely by Ea Energy Analyses.

The technology trends within generation capacity of recent years have shown how continued technological improvements pave the way towards lower prices and even new technologies into the spectrum of the focus for this report. Because of the rapid development for many of the existing and emerging technologies, this updated version of the technology catalogue comes at a vital time, securing updated data and information. The update is key to provide and establish a good understanding of technologies in terms of price and performance ensuring up-to-date and well-informed energy planning.

Via multi-stakeholder involvement in the data collection process, the technology catalogue contains data that has been scrutinised and discussed by a broad range of relevant stakeholders including but not limited to: DG Electricity of MEMR, PLN, and NEC. The broad participation is essential as one of the main objectives is letting the technology catalogue become well anchored amongst all stakeholders. With a common reference point, future energy planning and scenarios become more transparent. In this report all stakeholders have agreed that the published data are the best estimate based on current available knowledge.

The technology catalogue will assist the long-term energy modelling in Indonesia and support government institutions, private energy companies, think tanks and others in developing relevant policies and business strategies to achieve the government's long-term renewable energy targets and the overall power sector decarbonisation efforts in Indonesia.

Jisman P. Hutajulu
Director General of Electricity
Ministry of Energy and Mineral Resources

Kristoffer Böttzauw
Director General
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Kata pengantar (BAHASA)

Katalog teknologi ini merupakan versi revisi dan pemutakhiran dari katalog teknologi Indonesia yang sebelumnya diterbitkan pada tahun 2021. Katalog versi baru ini telah disusun selama tahun 2023 oleh Direktorat Jenderal Ketenagalistrikan, Kementerian Energi dan Sumber Daya Mineral bersama-sama dengan *Danish Energy Agency* Kedutaan Besar Denmark dan– didukung oleh Ea Energy Analyses.

Tren teknologi kapasitas pembangkitan dalam beberapa tahun terakhir telah menunjukan bagaimana kemajuan teknologi yang berkelanjutan membuka jalan untuk tren harga yang lebih rendah bahkan untuk teknologi baru hingga menjadi fokus dari laporan ini. Karena pesatnya perkembangan teknologi yang sudah dan yang sedang berkembang, versi terbaru dari katalog teknologi ini hadir pada saat yang sangat penting, mengamankan data dan informasi terkini. Pembaruan ini merupakan kunci untuk memberikan dan membangun pemahaman yang baik tentang teknologi dalam perihal harga dan kinerja untuk memastikan perencanaan energi yang terkini dan terinfokan dengan baik.

Melalui keterlibatan multi-pihak dalam proses pengumpulan data, katalog teknologi berisi data yang telah diteliti dan dibahas oleh berbagai pemangku kepentingan terkait termasuk namun tidak terbatas pada: Ditjen Ketenagalistrikan Kementerian ESDM, PLN, dan Setjen DEN. Partisipasi luas sangat penting karena salah satu tujuan utama dari penyusunan dokumen ini adalah menjadikan katalog teknologi tertanam dengan baik di antara semua pemangku kepentingan. Dengan adanya titik acuan yang sama, perencanaan dan skenario energi masa depan menjadi lebih transparan. Dalam laporan ini seluruh pemangku kepentingan telah sepakat bahwa data yang dipublikasikan adalah perkiraan terbaik berdasarkan pengetahuan yang tersedia saat ini.

Katalog teknologi ini akan membantu pemodelan energi jangka panjang di Indonesia dan mendukung institusi pemerintah, perusahaan energi swasta, lembaga think-tank, dan lainnya dalam mengembangkan kebijakan dan strategi bisnis yang relevan untuk mencapai target energi terbarukan jangka panjang pemerintah dan upaya dekarbonisasi sektor ketenagalistrikan secara keseluruhan di Indonesia.

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METHODOLOGY

Introduction to methodology

The technologies described in this catalogue cover both very mature technologies and technologies which are expected to improve significantly over the coming decades, both with respect to performance and cost. This implies that the price and performance of some technologies may be estimated with a rather high level of certainty whereas in the case of other technologies, both cost and performance today as well as in the future are associated with a high level of uncertainty. All technologies have been grouped within one of four categories of technological development (described in the section about Research and Development) indicating their technological progress, their future development perspectives and the uncertainty related to the projection of cost and performance data.

The boundary for both cost and performance data is the generation assets plus the infrastructure required to deliver the energy to the main grid. For electricity, this is the nearest land-based substation of the transmission grid. This implies that a MW of electricity represents the net electricity delivered, i.e. the gross generation minus the auxiliary electricity consumed at the plant. Hence, efficiencies are also net efficiencies.

Unless otherwise stated, the thermal technologies in the catalogue are assumed to be designed and operating for approx. 6000 full-load hours of generation annually (capacity factor of 70%). Some of the exceptions are municipal solid waste generation facilities and geothermal power plants, which are designed for continuous operation, i.e. approximately 8000 full-load hours annually (capacity factor of 90%).

Each technology is described by a separate technology sheet, following the format explained below. For the storage technologies and the CCS technologies, there are differences for some of the items in the qualitative and quantitative descriptions these are described in annex A and B.

Qualitative description

The qualitative description describes the key characteristics of the technology as concisely as possible. The following paragraphs are included if found relevant to the technology.

Technology description
Brief description for non-engineers of how the technology works and for which purpose, which makes it possible to understand the overall principles of the technology.

Input
The main raw materials, primarily fuels, consumed by the technology.

Output
The output of the technologies in the catalogue is electricity. Other outputs such as process heat are mentioned here.

Typical capacities
The stated capacities are for a single ‘engine’ (e.g. a single wind turbine or a single gas turbine), as well as for the total power plant consisting of a multitude of ‘engines’ such as a wind farm. The total power plant capacity should be that of a typical installation in Indonesia.

Ramping configurations and other power system services
Brief description of ramping configurations for electricity generating technologies, i.e. what are the part-load characteristics, how fast can they start up, and how quickly are they able to respond to demand changes (ramping).

Advantages/disadvantages
Specific advantages and disadvantages relative to equivalent technologies. Generic advantages are ignored; for example, renewable energy technologies mitigate climate risk and enhance the security of supply.

Environment
Particular environmental characteristics are mentioned, e.g. special emissions or the main ecological footprints.

Employment
Description of the employment requirements of the technology in the manufacturing and installation process as well as during operation. This will be done both by examples and by listing the requirements in the legal regulation for local content (from Minister Decree or Order No. 54/M-IND/PER/3/2012 and No. 05/M-IND/PER/2/2017). It is compulsory for projects owned or funded by the government or government-owned companies to follow these regulations.

Research and development
The section lists the most important challenges from a research and development perspective. Particularly Indonesian research and development perspectives are highlighted if relevant.

The section also describes how mature the technology is.

The first year of the projection is 2023 (base year). In this catalogue, it is expected that cost reductions and improvements in performance will be realized in the future.

This section accounts for the assumptions underlying the improvements assumed in the datasheet for the years 2030 and 2050.

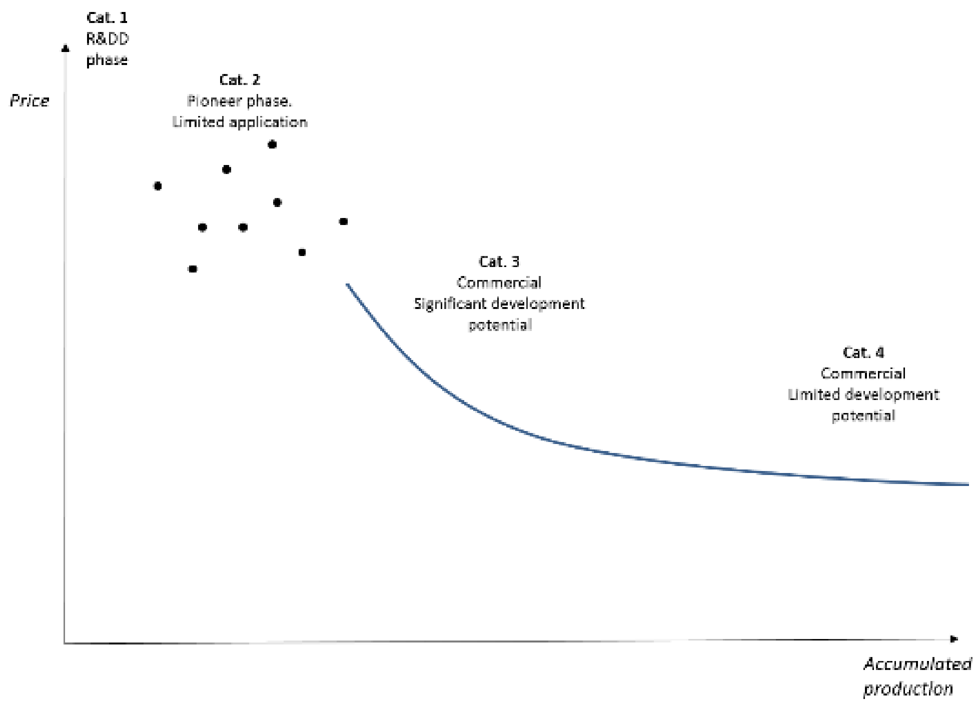
The potential for improving technologies is linked to the level of technological maturity. Therefore, this section also includes a description of the commercial and technological progress of the technology. The technologies are categorized within one of the following four levels of technological maturity.

<u>Category 1</u>. Technologies that are still in the *research and development phase*. The uncertainty related to price and performance today and in the future is very significant.

<u>Category 2</u>. Technologies in the *pioneer phase*. Through demonstration facilities or semi-commercial plants, it has been proven that the technology works. Due to the limited application, the price and performance are still attached with high uncertainty, since development and customization are still needed (e.g. gasification of biomass).

<u>Category 3</u>. *Commercial technologies with moderate deployment* so far. The price and performance of the technology today are well known. These technologies are deemed to have a significant development potential and therefore there is a considerable level of uncertainty related to future price and performance (e.g. offshore wind turbines)

<u>Category 4</u>. *Commercial technologies, with large deployment* so far. The price and performance of the technology today are well known, and normally only incremental improvements would be expected. Therefore, the future price and performance may also be projected with a fairly high level of certainty (e.g. coal power, gas turbine).



Technological development phases. Correlation between accumulated production volume (MW) and price.

Investment cost estimation

In this section *investment cost* projections from different sources are compared, when relevant. If available, local projects are included along with international projections from accredited sources (e.g. IEA, IRENA). On the top of the table, the recommended cost figures are highlighted. Local investment cost figures are reported directly when available, otherwise, they are derived from the result of PPAs, auctions and/or support mechanisms.

Cost projections for the new catalogue are added at the bottom of the table to show cost trends. Future cost developments are assessed individually for each technology based on provided references and input from stakeholders. The single technology is given a normalized cost of 100% in 2023 (base year); values smaller than 100% for 2030 and 2050 represent the technological learning, thus the relative cost reduction against the base year. An example of the table is shown below.

Investment costs [MUSD$_{2022}$/MW]		**2020**	**2023**	**2030**	**2050**
Catalogues	**New Catalogue (2023)**				
	Existing Catalogue (2020/21)				
Indonesia data	Local data I				
	Local data II				
International data (examples)	Danish technology catalogue				
	IRENA				
	IEA WEO				
Projection	Development – cost trend [%] compared to 2023.				

Examples of current projects
Recent technological innovations in full-scale commercial operations are mentioned, preferably with references and links to further information. This is not necessarily a Best Available Technology (BAT), but more of an indication of the standard that is currently being commissioned.

References
All descriptions shall have a reference, which is listed and emphasized in the qualitative description.

Quantitative description

To enable comparative analyses between different technologies data must be actually comparable and the report aims to standardise the data to the extent possible by setting certain definitions for the various technology parameters as described in the following sections. As an example, economic data is stated at the same price level and value-added taxes (VAT) or other taxes are excluded. In this context, taxes do not represent an actual cost but rather a transfer of capital between Indonesian stakeholders, the project developer and the government. The year 2023 is the base for the present status of the technologies and projcted future values are provided for 2030 and 2050. This generally refers to the year of commissioning, i.e. the first year of commercial operation of the plant.

Below is a typical datasheet, containing all parameters used to describe the specific technologies. The datasheet consists of a generic part, which is identical for groups of similar technologies (thermal power plants, non-thermal power plants and heat generation technologies) and a technology-specific part, containing information, that is only relevant for the specific technology. The generic technology part is made to allow for an easy comparison of technologies.

Each cell in the datasheet should only contain one number, which is the central estimate for the specific technology, i.e., no range indications. Uncertainties related to the figures should be stated in the columns called *uncertainty*. To keep the data sheet simple, the level of uncertainty is only specified for the years 2023 and 2050 and selected techno-economic parameters (financial data, key performance data). The uncertainty is related to the ‘market standard’ technology; in other words, the uncertainty interval does not represent the product range (for example a product with lower efficiency at a lower price or vice versa). For certain technologies, the catalogue covers a product range, this is for example the case for coal power, where both sub-critical, super-critical and ultra-super critical power plants are represented with individual sets.

The uncertainty is related to the specific parameters and cannot be read vertically in the table, meaning that the lower/upper bounds of one parameter are not related to the same lower/upper bound of another parameter (such as efficiency and financial data).

Most data in the datasheets are referenced to a number in the utmost right column (Ref), referring to sources specified below the table.

Before using the data, please note that essential information may be found in the notes below the table. If the data are based on specific cases, it is stated in the notes.

Appendix A and B includes descriptions of how and on which parameters the data sheets for storage and CCS differ from the one for power generating technologies.

The generic parts of the datasheets for thermal power plants, non-thermal power plants and heat generation technologies are presented in the table below:

Technology

Technology	Technology Name and Specifications								
	2023	2030	2050	Uncertainty (2023)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)									
Generating capacity for total power plant (MWe)									
Electricity efficiency, net (%), name plate									
Electricity efficiency, net (%), annual average									
Forced outage (%)									
Planned outage (weeks per year)									
Technical lifetime (years)									
Construction time (years)									
Space requirement (1000 m^2/MWe)									
Additional data for non thermal plants									
Capacity factor (%), theoretical									
Capacity factor (%), incl. outages									
Ramping configurations									
Ramping (% per minute)									
Minimum load (% of full load)									
Warm start-up time (hours)									
Cold start-up time (hours)									
Environment									
PM 2.5 (gram per Nm^3)									
SO_2 (degree of desulphuring, %)									
NO_X (g per GJ fuel)									
CH_4 (g per GJ fuel)									
N_2O (g per GJ fuel)									
Financial data									
Nominal investment (M\$/MWe)									
- of which equipment									
- of which installation									
Fixed O&M (\$/MWe/year)									
Variable O&M (\$/MWh)									
Start-up costs (\$/MWe/start-up)									
Technology specific data (examples)									
Exploration costs (M\$/MWe)									
Confirmation costs (M\$/MWe)									

References:

1

2

3

Notes:

A

B

C

Energy/technical data

Generating capacity
The capacity is stated for both a single unit, e.g. a single wind turbine or gas engine, and the total power plant, e.g. a wind farm or gas-fired power plant consisting of multiple gas engines. Unit and total power plant sizes represent typical power plants. Factors for scaling data in the catalogue to other plant sizes than those stated are presented later in this methodology section.

The capacity is given as net generation capacity in continuous operation, i.e. gross capacity (output from the generator) minus own consumption (house load), equal to the capacity available to the grid.

The unit MW_e is used for electric generation capacity (kW for small plants), and MW_h for heat generation, whereas the unit MJ/s is used for fuel consumption.

This describes the relevant product range in capacity (MW), for example, 200-1000 MW for a new coal-fired power plant. As mentioned above a single value is inserted in the cell in the data sheet, and the capacity range is described in a note. It should be stressed that data in the sheet is based on the typical capacity, for example, 600 MW for a coal-fired power plant. When deviations from the typical capacity range are made, the scale of economy effects need to be considered (see the section about investment cost).

Energy efficiencies
Efficiencies for all thermal plants are expressed in percentage at lower calorific heat value (lower heating value or net heating value) at ambient conditions in Indonesia, considering an average air temperature of approximately 28 °C.

The electric efficiency of thermal power plants equals the total delivery of electricity to the grid divided by the fuel consumption. Two efficiencies are stated: the nameplate efficiency as stated by the supplier and the expected typical annual efficiency.

Often, the electricity efficiency decreases slightly during the operating life of a thermal power plant. This degradation is not reflected in the stated data. As a rule of thumb, you may deduct 2.5 – 3.5%-points during the lifetime (e.g. from 40% to 37%).

Forced and planned outage
Forced outage is defined as a number of weighted forced outage hours divided by the sum of forced outage hours and operational hours. The weighted forced outage hours are the hours caused by unplanned outages, weighted according to how much capacity was out.

The forced outage is given in percent, while planned outage (for example due to renovations) is given in weeks per year.

Technical lifetime
The technical lifetime is the expected time for which an energy plant can be operated within, or acceptably close to, its original performance specifications, provided that normal operation and maintenance take place. During this lifetime, some performance parameters may degrade gradually but still stay within acceptable limits. For instance, power plant efficiencies often decrease slightly (a few percent) over the years, and operation and maintenance costs increase due to wear and degradation of components and systems. At the end of the technical lifetime, the frequency of unforeseen operational problems and risk of breakdowns is expected to lead to unacceptably low

availability and/or high operations and maintenance costs. At this time, the plant would be decommissioned or undergo a lifetime extension, implying a major renovation of components and systems as required to make the plant suitable for a new period of continued operation.

The technical lifetime stated in this catalogue is a theoretical value inherent to each technology, based on experience. In real life, specific plants of similar technology may operate for shorter or longer times. The strategy for operation and maintenance, e.g. the number of operation hours, start-ups, and the reinvestments made over the years, will largely influence the actual lifetime.

Construction time
Time from final investment decision (FID) until commissioning completed (start of commercial operation), expressed in years. Represents the time between when the financial closure is achieved, i.e. when financing is secured, and all permits are at hand, and the point of commissioning.

Space requirement
If relevant, space requirement is specified (1000 m^2 per MW). The space requirements may among other things be used to calculate the rent of land, which is not included in the financial data since the cost item depends on the specific location of the plant.

Average annual capacity factor
For non-thermal power generation technologies, a typical average annual capacity factor is presented. The average annual capacity factor represents the average annual net generation divided by the theoretical annual net generation, if the plant were operating at full capacity all year round. The equivalent full-load hours per year are determined by multiplying the capacity factor by 8760 hours, the total number of hours in a year.

The capacity factor for technologies like solar, wind and hydropower is very site-specific. In these cases, the typical capacity factor is supplemented with additional information, for example, maps or tables, explaining how the capacity will vary depending on the geographic location of the power plant. This information is normally integrated into the brief technology description.

The theoretical capacity factor represents the production realised, assuming no planned or forced outages. The realised full-loads consider planned and forced outages.

Ramping configuration

The electricity ramping configuration of the technologies is described by four parameters:

A. Ramping (% of nominal plant capacity per minute)
B. Minimum load (% of full load)
C. Warm start-up time (hours)
D. Cold start-up time (hours)

For several technologies, these parameters are not relevant, e.g. if the technology can ramp to full load instantly in on/off mode.

Parameter A defines the quality of a spinning reserve, that is the ability to ramp up or down to meet load requirements and frequency fluctuations.

Parameter B is the minimum load at which the plant can operate, which is typically set by stability reasons in the boilers and/or combustion chambers.

Parameter C refers to a power plant's ability to start up when the components' temperatures (boilers, turbines, etc.) are above ambient conditions. This condition is met when a thermal power plant has been idle for a limited amount of time, typically in the order of hours.

Parameter D refers to a power plant's ability to start up when the components' temperatures (boilers, turbines, etc.) are at ambient conditions. This condition is met when a power plant has been idle for a relatively long time, e.g. one day or more.

Environment

The plants should be designed to comply with the regulations that are currently in place in Indonesia. The latest regulation for environmental matters dates back to 2019 (*Peraturan Menteri Lingkungan Hidup dan Kehutanan Nomor P.15).* The regulation states values for the maximum allowed emission of Sulfur and Nitrogen Oxides, Particulate Matter (PM) and Mercury. These are reported in the table below.

NO	Parameter	Maximum Grade		
		Coal (mg / Nm 3)	Diesel oil (mg / Nm 3)	Gas (mg / Nm 3)
1	Sulfur Dioxide (SO_2)	200	350	25
2	Nitrogen Oxide (NO_x)	200	250	100
3	Particulate (PM)	50	30	10
4	Mercury (Hg)	0.03	-	-

CO_2 emission values are not stated in this catalogue, but these may be calculated by the reader by combining fuel data with technology efficiency data.

Where relevant, for example for gas turbines, emissions of methane (CH_4) and nitrous oxide (N_2O), which are strong greenhouse gases, are stated in g/ GJ of fuel or in mg/Nm^3 of fuel.

Emissions of particulate matter are expressed as PM 2.5 in g/GJ fuel.

SO_x emissions are calculated based on the following sulphur contents of fuels:

	Coal	Fuel oil	Gas oil	Natural gas	Wood	Waste	Biogas
Sulphur (kg/GJ)	0.35	0.25	0.07	0.00	0.00	0.27	0.00

The sulphur content can vary for different kinds of coal products. The sulphur content of coal is calculated from a maximum sulphur weight content of 0.8%.

For technologies, where desulphurization equipment is employed (typically large power plants), the degree of desulphurization is stated in percentage terms.

NO_x emissions account for both NO_2 and NO, where NO is converted to NO_2 in weight-equivalents. NO_x emissions are also stated in g/GJ fuel.

Financial data

Financial data are all in USD fixed prices, price-level 2022 and exclude value-added taxes (VAT) or other taxes. When comparing and converting financial data between different price years, the inflation rate is considered [1]. If financial data is available in other currencies, it's converted to USD first by considering the appropriate exchange rate:

Yearly average exchange rate between IDR and USD (source: World Bank)

Year	**IDR to USD**
2007	9,419
2008	10,950
2009	9,400
2010	9,090
2011	8,770
2012	9,386
2013	10,461
2014	11,865
2015	13,389
2016	13,308
2017	13,381
2018	14,237
2019	14,148
2020	14,582
2021	14,308
2022	14,849

There are several approaches to estimate future costs of generation technologies. This catalogue uses developments reported by generally accepted institutions or universities specifically for each type of technology. If no references on development are available, the learning rate approach is applied.

Investment costs
The investment cost or initial cost is reported on a normalized basis, e.g. cost per MW. The nominal cost is the total investment cost divided by the net generating capacity, i.e. the capacity as seen from the grid.

[1] Inflation rates used in the report is based on the US Consumer Price Index (CPS) published by the US Bureau of Labour Statistics

Where possible, the investment cost is divided into equipment cost and installation cost. Equipment cost covers the plant itself, including environmental facilities, whereas installation costs cover buildings, grid connection and installation of equipment.

Different organizations employ different systems of accounts to specify the elements of an investment cost estimate. Since there is no universally employed nomenclature, investment costs do not always include the same items. Actually, most reference documents do not state the exact cost elements, thus introducing an unavoidable uncertainty that affects the validity of cost comparisons. Also, many studies fail to report the year (price level) of a cost estimate.

In this report, investment costs shall include all physical equipment, typically called the engineering, procurement and construction (EPC) price or the *overnight cost*. Connection costs are included, but reinforcements are not included. It is here an assumption that the connection to the grid is within a reasonable distance.

The rent or buying of land is generally *not* included but may be assessed based on the space requirements specified under the energy/technical data (for some technologies it is mentioned specifically if the land costs are included). The reason for the land not being directly included is that land, for the most part, does not lose its value. It can therefore be sold again after the power plant has fulfilled its purpose and been decommissioned. In addition, estimations of land costs vary greatly depending on plant location and other assumptions used for specific studies in which the technology catalogue may be used.

The owners' predevelopment costs (administration, consultancy, project management, site preparation, and approvals by authorities) and interest during construction are not included. The cost to dismantle decommissioned plants is also not included. Decommissioning costs may be offset by the residual value of the assets.

Cost of grid expansion
As mentioned, the grid connection costs are included, however possible costs of grid expansion and reinforcements from adding new assets in the grid (generators, compensators, lines etc.) are not included in the presented data.

Business cycles
Business cycles follow general and cross-sectoral economic trends. As an example, the cost of energy equipment surged in 2007-2008 in conjunction with the financial crisis outbreak. In a study assessing generation costs in the UK in 2010, Mott MacDonald reported that "After a decade of cycling between $400 and $600 a kW installed EPC prices for CCGT increased sharply in 2007 and 2008 to peak at around $1250/kW in Q3:2008. This peak reflected tender prices: no actual transactions were done at these prices."

Such unprecedented variations make it difficult to benchmark data from recent years; furthermore, predicting the outbreak of global recessions and their impact on complex supply chains (such as the Covid-19 2020 crisis) is challenging. However, a catalogue as the present needs to refer to several sources and assume future courses. The reader is urged to bear this in mind when comparing the costs of different technologies.

Economy of scale
The per-unit cost of larger power plants is usually lower than that of smaller plants. This is the effect of 'economy of scale'. An empirical relationship between power plant size and their cost was analysed in the article "Economy of Scale in Power Plants" in the August 1977 issue of Power Engineering Magazine (p. 51). The basic equation linking costs and sizes of two different power plants is:

$$\frac{C_1}{C_2} = \left(\frac{P_1}{P_2}\right)^a$$

Where:
C_1 = Investment cost of plant 1 (e.g. in million US$)
C_2 = Investment cost of plant 2
P_1 = Power generation capacity of plant 1 (e.g. in MW)
P_2 = Power generation capacity of plant 2
a = Proportionality factor [-]

For many years, the proportionality factor averaged about 0.6, but extended project schedules may cause the factor to increase. However, used with caution, this rule may be applied to convert data in this catalogue to other plant sizes than those stated. It is important that the plants are essentially identical in construction technique, design, and time frame and that the only significant difference is size.

For very large plants, like traditional centralized coal power plants, the maximum power output has likely reached a plateau. Instead, the construction of multiple units at the same location can provide additional savings by sharing the balance of plant equipment and support infrastructure. Typically, about 15% savings in investment cost per MW can be achieved for gas combined cycle and big steam power plant from a twin unit arrangement versus a single unit ("Projected Costs of Generating Electricity", IEA, 2010). The financial data in this catalogue is all for single-unit plants (except for wind farms and solar PV), so one may deduct 15% from the investment costs, if very large plants are being considered. Unless otherwise stated the reader of the catalogue may apply a proportionality factor of 0.6 to determine the investment cost of plants of higher or lower capacity than the typical capacity specified for the technology. For each technology, the relevant product range (capacity) is specified.

Operation and maintenance (O&M) costs
The fixed share of O&M is calculated as cost per generating capacity per year ($/MW/year), where the generating capacity is the one defined at the beginning of this chapter and stated in the tables. It includes all costs, which are independent of how many hours the plant is operated, e.g. administration, operational staff, payments for O&M service agreements, network or system charges, property tax, and insurance. Any necessary reinvestments to keep the plant operating within the technical lifetime are also included, whereas reinvestments to extend the operational life beyond the technical lifetime are excluded. Reinvestments are discounted at a 4% annual discount rate in real terms. The cost of reinvestments to extend the lifetime of the plants may be mentioned in a note if data is available.

The variable O&M costs ($/MWh) include consumption of auxiliary materials (water, lubricants, fuel additives), treatment and disposal of residuals, spare parts and output-related repair and maintenance (however not costs covered by guarantees and insurances). Planned and unplanned maintenance costs may fall under fixed costs (e.g. scheduled yearly maintenance works) or variable costs (e.g. works depending on actual operating time), and are split accordingly.

Fuel costs are not included.

It should be noted that O&M costs often develop over time. The stated O&M costs are therefore average costs during the entire lifetime.

Start-up costs

The O&M costs stated in this catalogue include start-up costs and consider a typical number of start-ups and shut-downs. Therefore, the start-up costs should not be specifically included in more general analyses. They should only be used in detailed dynamic analyses of the hour-by-hour load of the technology.

Start-up costs are stated in costs per MW of generating capacity per start-up (€/MW/startup), if relevant. They reflect the direct and indirect costs during a start-up and the subsequent shutdown.

The direct start-up costs include fuel consumption, e.g. fuel which is required for heating boilers, and which does not yield usable energy, electricity consumption, and variable O&M costs corresponding to full load during the start-up period.

The indirect costs include the theoretical value loss corresponding to the lifetime reduction for one start-u u. For instance, during the heating-up, thermal and pressure variations will cause fatigue damage to components, and corrosion may increase in some areas due to e.g., condensation.

An assumption regarding the typical number of start-ups is made for each technology to calculate the O&M costs. This assumption is specified in the notes. The following table shows the assumed number of start-ups per year included in the O&M costs for some technologies.

Numbers of start-ups included in the stated O&M cost	Assumed number of startups per year
Coal CHP	15
Natural gas CHP (except gas engines)	30
Gas Engines	100
Wood pellet CHP	15
Heat only boilers	50
Municipal solid waste / biogas standalone	5
Geothermal heat	5
Heat pumps	3
Electric boilers	100

The stated O&M costs may be corrected by the difference in the numbers of start-ups:

$$O\&M_{new} = O\&M_{old} + Start\text{-}up\ cost * (n_{new,start\text{-}up} - n_{old,start\text{-}up})$$

Where $n_{old,start\text{-}up}$ is the number of start-ups specified in the notes for the specific technology and $n_{new,start\text{-}up}$ is the desired number of start-ups.

Technology specific data

Technology-specific data are included in the last rows in the data sheets here parameters that are critical for the economy or performance of the technology is included. In the following guidelines for how to evaluate the parameters are given for a few of the technologies, since it is assumed that for most of the parameters no definitions are needed.

1. Geothermal Power Plant

Brief technology description
Geothermal power plants take advantage of underground reservoirs at relatively high temperatures to run a variety of Rankine cycles. The geothermal fluid is extracted from a production well which can be characterized by its average temperature (or enthalpy). In 1990, Hochstein proposed the following categorization of geothermal reservoirs (ref. 1):

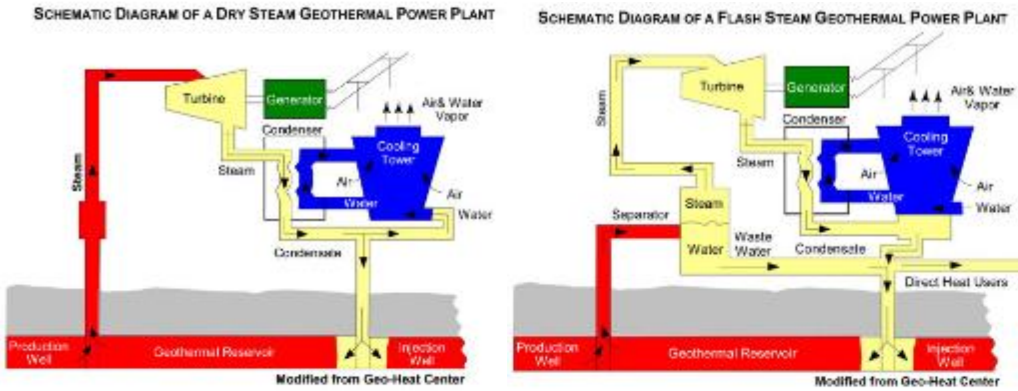
1. Low-temperature (enthalpy) geothermal wells with reservoir temperatures below 125°C
2. Medium-temperature (enthalpy) geothermal wells with reservoir temperatures between 125°C and 225°C
3. High-temperature (enthalpy) geothermal wells whose temperatures exceed 225°C.

In Indonesia, geothermal resources are mainly classified as hydrothermal geothermal systems with high temperatures (> 225°C). Only a few geothermal resources have lower temperatures and can be considered as medium enthalpy.

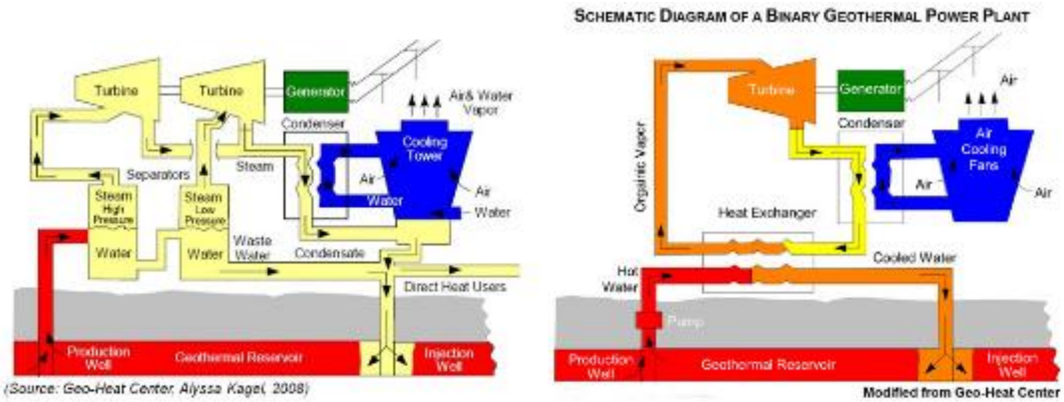
The plant configuration at the geothermal site depends on the application and on the type of geothermal fluid available in the underground, which is its thermodynamic and chemical properties. Geothermal to electrical power conversion systems in use in the world today may be divided into four major energy conversion systems:

- Dry steam plants (found in high-temperature geothermal fields) are used at vapor-dominated reservoirs. The geothermal fluid must be predominantly composed of steam to avoid fast wearing and corrosion of the plant's components. These plants usually make use of saturated or slightly superheated steam
- Flashed steam plants (found in high-temperature geothermal fields), used at water-dominated reservoirs and more specifically
  - Single flash plants (only for high-pressure flash steam)
  - Double flash plants (for both low and high-pressure flash steam)
- Binary or twin-fluid system (found in medium-temperature geothermal fields), based upon Kalina or Organic Rankine Cycles (ORC).
- Hybrid/Combined Cycle, which is a combined system comprising two or more of the above basic types in series and/or in parallel. Typically, binary plants can be used as bottoming cycles to exploit residual heat from a topping (flash) plant or other heat production systems can be incorporated to boost the plant efficiency, such as Concentrated Solar Power (CSP).

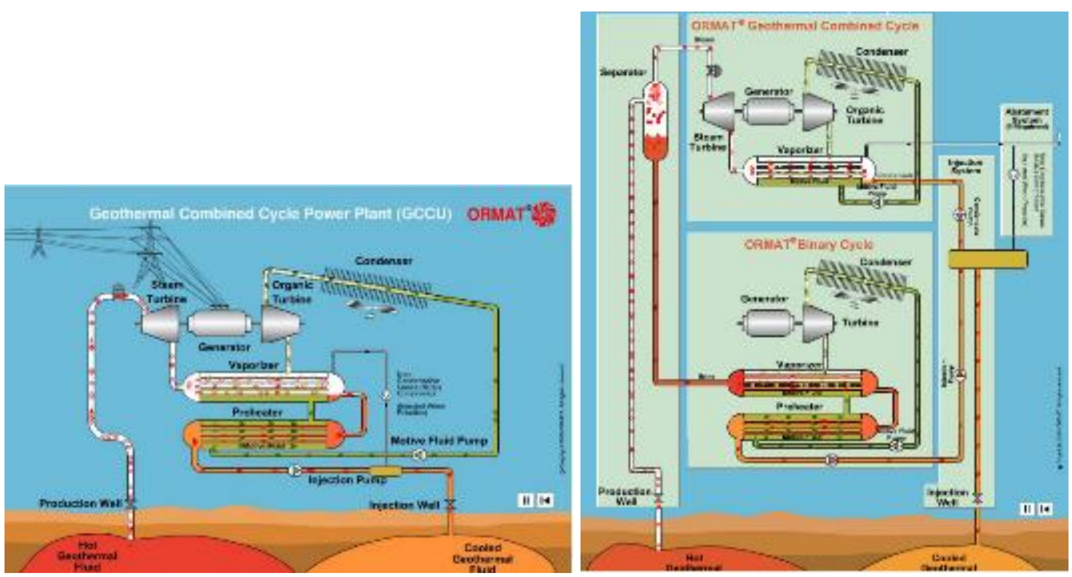
Condensing and back pressure type geothermal turbines are essentially low-pressure machines designed for operation at a range of inlet pressures ranging from about 20 bar down to 2 bar and saturated steam. A condensing type of system is the most common type of power conversion system in use today. Depending on the geothermal fluid characteristics, plant type and system frequency, geothermal turbines are manufactured in different sizes, up to 120 MW. Binary type low/medium temperature units, such as the Kalina cycles or ORCs, are typically manufactured in smaller sizes, i.e., ranging between 1 MW and 10 MW nominal output. Larger units tailored to specific uses are, however, available at higher prices.



Direct and single flashed steam plants (ref. 7)



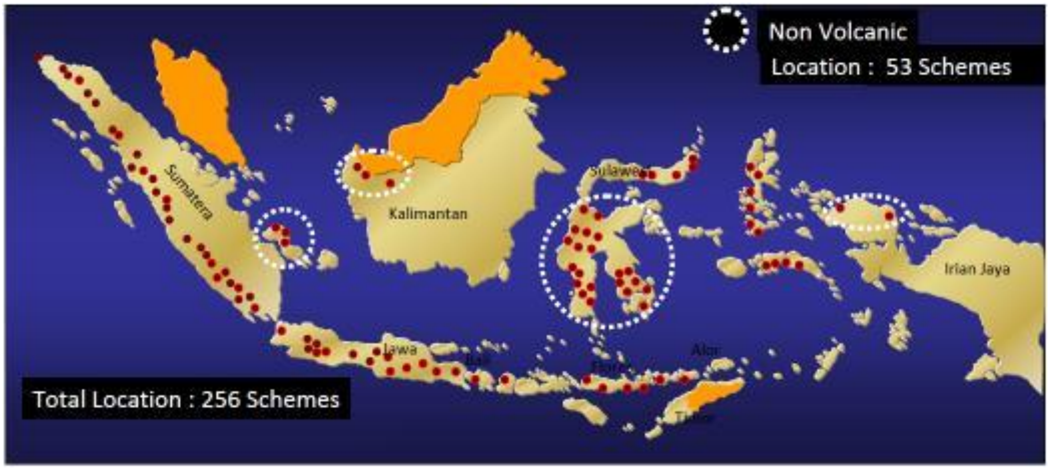
Double flashed and binary steam plants (ref. 7)



Hybrid/Combined Cycle plant (ref. 8)

The total capacity of geothermal power plants installed in 2022 in Indonesia was 2.360 MW spread across 18 different locations (Ref. 2). In the same year, geothermal power plants generated electricity for around 16.6 TWh. This equals an average capacity factor of over 80%, but several specific sites can achieve higher levels than that. The current installed units have a capacity ranging from 2.5 to 120 MW per unit.

Indonesia has the largest geothermal resources potential in the world of about 23 GW, which comprises 9.2 GW of resources and 13.8 GW of reserves (ref. 2). The geothermal potential in Indonesia is mainly from volcanic-type systems; for instance, the country has over 100 volcanoes located along the Ring of Fire.



Distribution of geothermal resources in Indonesia.

Geothermal resources and reserves potential (based on Ref. 2))

No	Islands	Resources (MW)		Reserves (MW)			Total
		Speculative	Hypothetical	Probable	Possible	Proven	(MW)
1	Sumatera	2,188	1,567	3,514	876	1,169	9,305
2	Jawa	1,164	1,270	3,121	363	1,855	7,773
3	Bali & Nusa Tenggara	70	219	104	110	30	335
4	Kalimantan	151	18	6			175
5	Sulawesi	1,352	342	99	180	120	2,990
6	Maluku	560	80	496	6	2	1,144
7	Papua	75					75
Total Sum		5,775	3,444	8,968	1,664	3,210	23,060

Input
Heat from brine (saline water) from underground reservoirs.

Output
Electricity (heat can be recovered in cogeneration systems).

Typical capacities
2.5-110 MW per unit.

Ramping configurations
The general experience is that geothermal energy should be used as a base load to ensure an acceptable return on investment. For most geothermal power plants, flexibility is more of an economic issue than a technical one.

Advantages/disadvantages
Advantages:
- High degree of availability (>98% and 7500 operating hours/annum is common).
- Small ecological footprints.
- Almost zero liquid pollution with re-injection of liquid effluents.
- Insignificant dependence on weather conditions.
- Comparatively low visual impact.
- Established technology for electricity production.
- Cheap running costs and "fuel" free.
- Renewable energy sources and environmentally friendly technology with low CO_2 emission.
- High operation stability and long lifetime.
- Potential for combination with heat storage and/or other process heat applications.
- Geothermal is distinct from variable renewables, such as wind and solar, because it can provide consistent electricity throughout the day and year.

Disadvantages:
- No certainty of success before the first well is drilled and the reservoir has been tested (ref. 11). A high risk exists in the first phases of the geothermal project (exploration, tests, etc.).
- High initial costs.
- The best reservoirs are not always located near cities.
- Need access to base-load electricity demand.
- The impact of the drilling on the nearby environment.
- Risk of mudslides if not handled properly.
- The pipelines to transport the geothermal fluids will have an impact on the surrounding area.
- Geothermal resource depletion if the withdrawal rate from the reservoir is too high.

Environment
Steam from geothermal fields contains Non-Condensable Gas (NCG) such as Carbon Dioxide (CO_2), Hydrogen Sulphide (H_2S), Ammonia (NH_3), Nitrogen (N_2), Methane (CH_4) and Hydrogen (H_2). Among them, CO_2 is the largest element within the NCG's discharge. CO_2 constitutes up to 95 to 98% of the total gases, hydrogen sulphide (H_2S) constitutes only 2 to 3%, and the other gasses are even less abundant.

H_2S is a colourless, flammable, and extremely hazardous gas. It causes a wide range of health effects, depending on concentration. Low concentrations of the gas irritate the eyes, nose, throat and respiratory system (e.g., burning/tearing of eyes, cough, shortness of breath). The safety threshold for H_2S in humans can range from 0.0005 to 0.3 ppm.

CO_2 and H_2S are the dominant chemical compounds in geothermal steam, thus this catalogue delivers data on CO_2 and H_2S emissions from geothermal power plants in Indonesia.

NCG concentrations from each geothermal field are different. NCG emissions from the Wayang Windu field would be 1.1%, and emissions from the Kamojang field would be 0.98%. Both of the fields produce dry steam. Ulubelu (double-flash + binary plant) has NCG concentrations of 0.68%. The average NCG emissions from the three fields are 0.92% (ref. 3).

The table below shows the emissions concentrations of CO_2 and H_2S from three commissioned geothermal power plants in Indonesia. From the table, emissions of CO_2 range from 42 to 73 g/kWh with an average value of 62.90 g/kWh. For H_2S, the values range between 0.14 to 2.54 g/kWh with an average value of 1.45 g/kWh (ref. 3).

CO_2 and H_2S emission from geothermal power plant in Indonesia.

Power plant	Capacity (MWe)*	Emission (g/kWh)	
		CO_2	H_2S
Wayang Windu	227	73.48	2.54
Kamojang	235	72.57	0.14
Ulubelu	165	42.64	1.68
	Average:	62.90	1.45

**Total capacity in 2016*

Employment

During construction, the development of Lahendong Unit 5 and 6 and Ulubelu Unit 3 Geothermal Power Plants with a total installed capacity of 95 MW have created around 2,750 jobs for the local workforce. These power plants began to operate commercially in December 2016.

Research and development

Geothermal power plants are considered as a category 3 – i.e. commercial technologies, with potential for improvement.

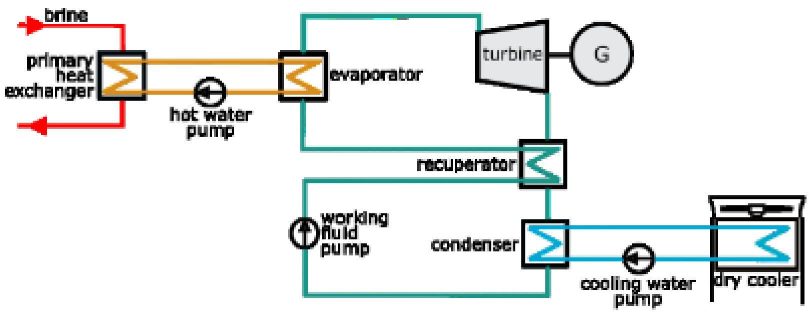
To successfully demonstrate binary power plant technologies at an Indonesian site and to stimulate the development of this technology, a German-Indonesian collaboration involving GFZ Potsdam (Germany), the Agency for the Assessment and Application of Technology in Indonesia (BPPT) and PT Pertamina Geothermal Energy (PGE) has been initiated. The basis for this collaboration was established within the German-Indonesian cooperation project "Sustainability concepts for exploitation of geothermal reservoirs in Indonesia" which started in 2009. Since then, several research activities have been carried out in the field of integrated geosciences and fluid chemistry (ref. 6). In the field of plant technology, the technical concept for a demonstration binary power plant at the Lahendong (LHD), North Sulawesi site has been elaborated (ref. 4). The realization of the demonstration 550 kW binary power plant is carried out in a separate collaboration project which was officially granted in October 2013. Due to technical problems, the commissioning for the demonstration of a binary cycle power plant has not yet been conducted. Commissioning will be conducted in mid-September 2017.

The binary power plant will use brine from the well pad of LHD-5. The brine temperature is about 170°C corresponding to a separator pressure of 8.5 bar(g). The total mass flow will be about 110 t/h. The brine outlet temperature should be about 140 °C since it should be possible to inject the hot brine back into the reservoir in the western part of the geothermal system.

The power plant cycle will be a subcritical, single-stage Organic Rankine Cycle (ORC) with internal heat recovery using n-pentane as the working fluid. For low maintenance and high reliability of the ORC, no rotating sealing is used in the conversion cycle. The feed pump will be a magnetically coupled type. The turbine-stage and generator will be mounted in one body and are directly connected by the shaft.

In the figure below, it can be seen how the ORC-module is not directly driven by the geothermal fluid, since a water cycle between the brine cycle and ORC will be used. Material selection and design of the primary heat exchanger can hence be based on the brine composition whereas the evaporator design can be optimized with a focus on the thermo-physical characteristic of the working fluid. For the heat removal from the ORC to the ambient using air-cooled equipment, an intermediate water cycle is also planned to minimize potential risks of malfunction in the conversion cycle. Using a water-cooled condenser also has the advantage of facilitating a factory test of the complete ORC-module before the final installation at the site. Both intermediate cycles will lead to a loss in power output due to the additional heat resistance and the additional power consumption by the intermediate cycle pumps and entail additional costs. However, the gain in plant reliability was considered to outweigh the power loss for this demonstration project. An intermediate cycle on the hot side might, however, also be advantageous for other sites.

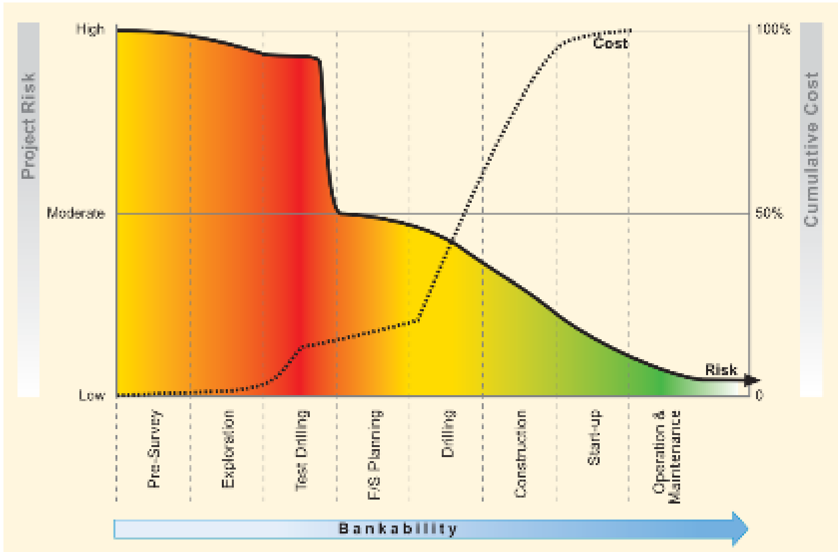
The installed capacity will be about 550 kWe. The auxiliary power consumption is estimated to be lower than 20%.



Technical concept of the demonstration power plant (ref. 4)

Investment cost estimations, overview of examples of costs

The investment costs of a geothermal project are heavily influenced by the exploration and drilling phases and by the type of geothermal power plant (flash or binary). Site selection and preparation are associated with a certain risk in the development of the geothermal project, thereby increasing the plant's cost of capital. The figure below illustrates the relationship between risk and cumulative costs in a geothermal project.



Qualitative risk and cumulative cost trends of a geothermal project. Source: Geothermal Handbook: Planning and Financing Power Generation, ESMAP, 2012.

Cost figures can therefore span over wide ranges. Flash plants are more economical because of an overall lower need for equipment, while the presence of an ORC (binary plants) increases project costs. Generally, the costs between projects vary a lot and IRENA reports estimated costs ranging from below 2 MUSD/MW to above 8 MUSD/MW during the last 15 years due to site-specific factors. Cost data from relevant sources are reported in the table below, along with the recommended values for the investment costs.

Geothermal projects also have significant costs related to the continued management of the site to maintain the capacity output and performance throughout the lifetime. These costs are included in the fixed O&M category, estimated at around 110.000-145.000 USD/MW depending on plant type to cover makeup and re-injection of two wells throughout the lifetime.

Investment costs [MUSD$_{2022}$/MW]		**2020**	**2023**	**2030**	**2050**
Catalogues	**New Catalogue (2023)**		**4.40** (flash) **5.50** (binary)	**4.40** (flash) **5.50** (binary)	**3.96** (flash) **4.95** (binary)
	Existing Catalogue (2020)	4.56 (flash) 5.70 (binary)		3.92 (flash) 4.90 (binary)	3.24 (flash) 4.05 (binary)
Indonesian data	MEMR FGDs 2023[1]		3.78-4.73		
	ESDM[2]	5.00			
	Literature[3]		2.85		
	IRENA[4]	4.04-4.62	3.48		

International data	NREL ATB[5]		4.58 (flash) 6.00 (binary)	3.88 - 4.52 (flash) 4.83 - 6.00 (binary)	3.19 - 4.09 (flash) 3.99 - 5.44 (binary)
	Lazard[6]		4.70 - 6.10		
Projection	Development curve – cost trend [%]	-	100%	100%	90%

[1]*MEMR Focus Group Discussions with various stakeholders for the purposes of updating the Technology Catalogue in 2023*
[2]*ESDM presentation on "KATADATA Shifting Paradigm: Transition towards sustainable energy". Sampe L. Purba (26 August 2020)*
[3]*Insani, N.A, Analisis Keekonomian Pembangkit Listrik Tenaga Panas Bumi Kapasitas Kecil Sistem Siklus Uap, Journal of Electrical Power, 2019.*
[4]*IRENA Renewable Power Generation Costs in 2022. Investment costs have been at similar levels for period 2012-2022, estimate for 2020 refers to average 2018-2020.*
[5]*NREL Annual Technology Baseline 2023*
[6]*Lazard's Levelized Cost of Energy Analysis - Version 16.0, 2023*

Examples of current projects

Large Scale Geothermal Power Plant: Muara Laboh Geothermal Power Plant (Ref. 13)

Muara Laboh Geothermal Power Plant is located at West Solok in West Sumatra Province. The potential power capacity that can be generated from the wells is about 250 MW. Based on current calculations, 24 to 27 wells are needed to maintain the 250 MW generating capacity. This project is owned by PT Supreme Energy Muara Laboh (SEML), a joint venture of PT Supreme Energy, French ENGIE and Japanese Sumitomo Corporation. The electricity generated by this geothermal project will be sold to PT PLN (Persero) under a Power Purchase Agreement (PPA) for 30 years at a selling price of 13 US cents/kWh.

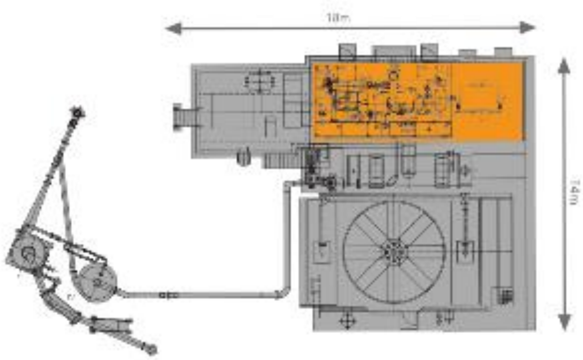
The project started developing wells in 2010. For the first stage, the company completed the exploration drilling program covering 6 wells. The company confirmed that it is sufficient to build a power plant with a capacity of 85 MWe. The first stage 85 MW Geothermal Power Plant was commercially in operation on 16 December 2019. This plant applies a single and dual flash steam cycle since the geothermal source is in the form of two phases (water and vapour) with an enthalpy value between 1,025 and 2,000 kJ/kg. During the construction period, the project will employ 2000 – 2500 people. During the operation stage, number of manpower to be recruited ranges from 200 to 240 people from various fields of expertise. The initial estimate of land needs is about 55 ha.

The capital cost of the first stage project is 580 million USD. The second stage of Muara Laboh Geothermal Power Plant has been initiated. The planned power capacity is 65 MWe and the estimated capital cost is about 400 million USD.

Muara Laboh Geothermal Power Plant (Ref. 14)

Small Scale Geothermal Power Plant: Dieng Geothermal Power Plant (Ref. 15)
Dieng Geothermal Power Plant is an example of a small-scale geothermal project in Indonesia. It is located at Dieng Plateau in Central Java. The owner of the project is PT Geo Dipa Energy. Dieng Plateau offers a great potential for geothermal sources as a number of other bigger geothermal plants are already operational. The location of the 10 MW Geothermal Power Plant is close to Dieng Unit 1 Geothermal Power Plant with an installed capacity of 55 MW which is also owned by the same company. The project is currently underway. The plant was planned to be in operation by the end of 2020 with an expected investment cost of 21 million USD.

The most interesting of the project is that Toshiba Energy System & Solutions Corporation (Toshiba ESS) will supply a set of steam turbines and generators for this 10-MW geothermal power plant called Geoportable. The Geoportable is a compact power generation system developed by Toshiba ESS for small-scale geothermal power plants with outputs ranging from 1 MW to 20 MW. The system uses state-of-the-art technology, for example, the best corrosive gas-resistant materials, which are essential for geothermal steam turbines, and the unique design of the steam line, to achieving high performance and reliability. In addition, with its compact design, the Geoportable can be installed even in confined areas where conventional geothermal power generation systems are usually not sufficient. The Geoportable consists of several standard components that are pre-assembled on a factory skid, allowing for shorter build and installation times. This technology is for single-flash steam system plants.




The Geoportable by Toshiba ESS (Ref. 16)

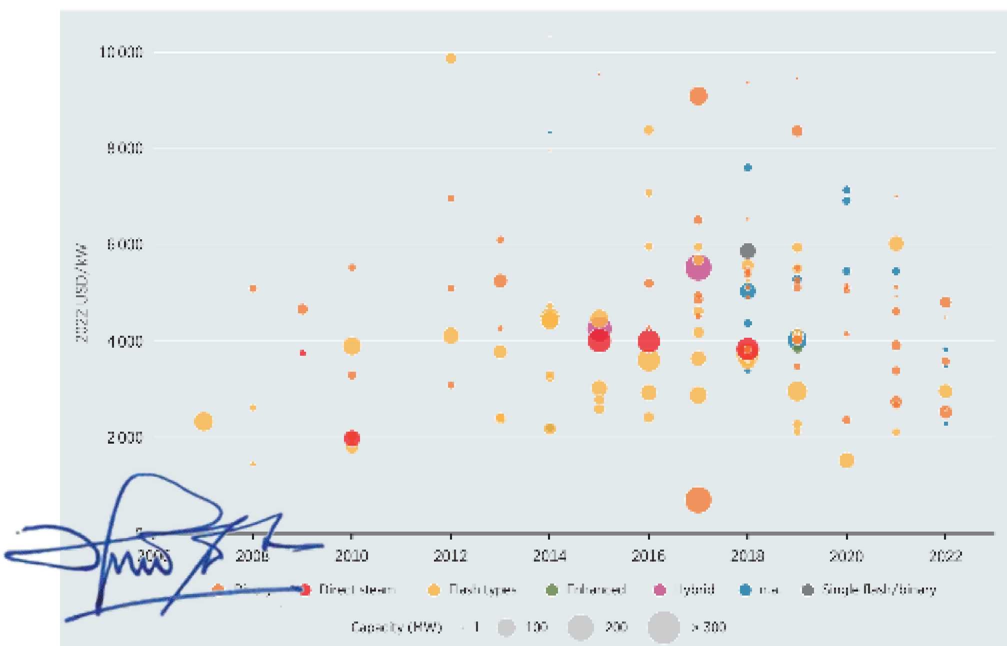
PT Geo Dipa is also constructing a 10-15 MW Organic Rankine Cycle Power Plant (Binary) at the same site and it will be commercially in operation in 2021.

PT Sorik Marapi Geothermal Power (ref 17)
One of the largest developing geothermal projects in Indonesia. This project is located in Mandailing Natal Regency, North Sumatera Province. KS Orka acquired majority shares of the company in mid-2016 and since then the project has completed a drilling program for 18 wells and confirmed at least 55 MW of proven resources, with further exploration of up to 240 MW.

Additional remarks
The conversion efficiency of geothermal power plants is generally lower than that of other conventional thermal power plants. The overall conversion efficiency is affected by many parameters including the power plant design (single or double flash, triple flash, dry steam, binary, or hybrid system), size, gas content, parasitic load, ambient conditions, and others. The figure below shows the conversion efficiencies for binary, single flash-dry steam, and double flash. The figure shows that double flash plants have higher conversion efficiency than single flash, but

can have lower efficiency than binary plants for the low enthalpy range (750-850 kJ/kg). This has a direct impact on the specific capital of the plant as shown in the following figure.

Geothermal plant efficiency as a function of temperature and enthalpy (ref. 5)



Project-level costs for geothermal projects in the world by year and plant type (ref. 10)[2].

Technology specific data, exploration cost
Calculating the exploration cost for geothermal energy involves several steps and various factors that reflect the complexity and uncertainty of geothermal exploration. The total exploration cost is the sum of these costs.

Preliminary Survey Costs: This includes the cost of geological, geochemical, and geophysical surveys. Each survey requires different equipment, expertise, and time, and the costs can vary significantly based on these factors.

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[2] *Enhanced* geothermal power plants are a type of plant where the resource is exploited through a fracking process, but do not designate a specific type of power cycle (which can be any of the four types mentioned at the beginning of this Chapter).

Exploratory Drilling Costs: The costliest part of the exploration phase is exploratory drilling, which provides direct information about the site's geothermal potential. The drilling costs depend on the site's geology, the depth of the resource, and the number and depth of the wells drilled.

Environmental Impact Assessment (EIA) Costs: This includes the costs of conducting environmental studies to understand the potential environmental impact of a geothermal project, which is a legal requirement in many jurisdictions.

Administrative Costs: This includes overheads such as project management, permitting, legal and consultation fees.

Contingency Costs: Given the inherent uncertainty in exploration, a contingency cost is often added to the budget to account for unforeseen expenses.

The actual exploration cost costs vary significantly depending on the site's characteristics, regulatory requirements, and market conditions. Therefore, it is recommended to include in the datasheet a generic value found in the international literature and to state clearly in the notes that it is a value that varies significantly, thus should be considered on plant level.

Technology-specific data, confirmation cost

Confirmation cost for geothermal energy refers to the expenses associated with validating the results obtained during the exploration phase. After identifying a potential geothermal reservoir, the next step is to confirm the site's productivity, the reservoir characteristics, and the feasibility of power production. This phase is crucial as it reduces risks and uncertainties before significant financial commitments are made for development.

Here's a framework for calculating the confirmation cost, the total confirmation cost is the sum of all these costs:

Confirmatory Drilling Costs: This includes the cost of drilling additional wells to confirm the results from the exploratory drilling. Costs will depend on factors such as the depth and number of wells, and the site's geology.

Reservoir Testing and Modelling Costs: These costs cover testing the drilled wells and modelling the reservoir to assess its size, temperature, pressure, and other properties.

Feasibility Study Costs: This includes the costs of preparing a detailed technical and financial feasibility study based on the results of confirmatory drilling and reservoir testing.

Administrative Costs: This consists of overheads like project management, legal fees, and permit applications.

Contingency Costs: Given the uncertainties in confirming geothermal resources, a contingency cost is often added to account for potential unforeseen expenses.

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Datasheets

The following pages contain the data sheets of the technology. All costs are stated in U.S. dollars (USD), price year 2022. The uncertainty is related to the specific parameters and cannot be read vertically – meaning a product with e.g. lower efficiency does not have a lower price.

Technology

Technology	Geothermal power plant - large system (flash or dry)								
	2023	2030	2050	Uncertainty (2023)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	55	55	55	30	500	30	500		1
Generating capacity for total power plant (MWe)	110	110	110	30	500	30	500		1
Electricity efficiency, net (%), name plate	16	17	18	8	18	10	20	A	5
Electricity efficiency, net (%), annual average	15	16	17	8	18	10	20	A	5
Forced outage (%)	10	10	10	5	30	5	30		1
Planned outage (weeks per year)	4	4	4	2	6	2	6		1
Technical lifetime (years)	30	30	30	20	50	20	50		1,10
Construction time (years)	2	2	2	1,5	3	1,5	3	H	1,10
Space requirement (1000 m^2/MWe)	30	30	30	20	40	20	40		1
Additional data for non thermal plants									
Capacity factor (%), theoretical	90	90	90	70	100	70	100		1
Capacity factor (%), incl. outages	80	80	80	70	100	70	100		1
Ramping configurations									
Ramping (% per minute)	3	10	20						8
Minimum load (% of full load)									
Warm start-up time (hours)									
Cold start-up time (hours)									
Environment									
PM 2.5 (gram per Nm^3)	-	-	-	-	-	-	-	C	6
SO_2 (degree of desulphuring, %)	-	-	-	-	-	-	-	C	6
NO_X (g per GJ fuel)	-	-	-	-	-	-	-	C	6
CH_4 (g per GJ fuel)	-	-	-	-	-	-	-	C	6
N_2O (g per GJ fuel)	-	-	-	-	-	-	-	C	6
Financial data									
Nominal investment (M$/MWe)	4,40	4,40	3,96	3,30	5,50	1,70	5,10	B,D,E,F	1,2,3,4
- of which equipment	60%	60%	60%	40%	70%	40%	70%		9
- of which installation	40%	40%	40%	30%	50%	30%	50%		9
Fixed O&M ($/MWe/year)	110.000	110.000	99.000	82.500	137.500	74.250	123.750	B,D,G	3,11
Variable O&M ($/MWh)	0,27	0,27	0,24	0,20	0,34	0,30	0,18	B,D	1,4
Start-up costs ($/MWe/start-up)	-	-	-	-	-	-	-		
Technology specific data									
Exploration costs (M$/MWe)	0,16	0,15	0,15	0,11	0,21	0,11	0,21		7
Confirmation costs (M$/MWe)	0,16	0,15	0,15	0,11	0,21	0,11	0,21		7

References:

1 MEMR Focus Group Discussions with various stakeholders for the purposes of updating the Technology Catalogue in 2023

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4 Learning curve approach for the development of financial parameters.

5 Moon & Zarrouk, 2012, "Efficiency Of Geothermal Power Plants: A Worldwide Review".

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Notes:

A The efficiency is the thermal efficiency - meaning the utilization of heat from the ground. Since the geothermal heat is renewable and considered free, then an increase in effciency will give a lower investment cost per MW. These large units are assumed to be flach units at high source temperatures.

B Uncertainty (Upper/Lower) is estimated as +/- 25%, which is an estimate build upon cases from IRENA (ref. 9)

C Geothermal do emit H_2S. From Minister of Environment Regulation 21/2008 this shall be below 35 mg/Nm^3.

D The learning rate is assumed to impact the geothermal specific equipment and installation. The power plant units (i.e. the turbine and pump) is assumed to have very litle development. From Ref. 9 it is assumed that half of the investment cost are on the geothermal specific equipment.

E Investment cost are including Exploration and Confirmation costs (see under Technology specific data).

F For 2020, uncertainty ranges are based on cost spans of various sources. For 2050, we combine the base uncertainity in 2020 with an additional uncertainty span based on varying learning rates

G O&M includes costs related to the continous management of the geothermal site to maintain capacity and performance. Given cost is estimated for two sets of wells for makeup and reinjection over the 25-year life of the project to maintain performance.

H Refers to construction of the steam cycle power plant itself. Preperation of the geothermal site includes surveying, exploration, drilling, resource confirmation, which can take 4-5 years in total.

Technology

Technology	Geothermal power plant - small system (binary or condensing)								
	2023	2030	2050	Uncertainty (2023)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	10	10	10	0.3	20	0	20		1,8
Generating capacity for total power plant (MWe)	20	20	20	5	30	5	30		1
Electricity efficiency, net (%), name plate	10	11	12	6	12	8	14	A	5
Electricity efficiency, net (%), annual average	10	11	12	6	12	8	14	A	5
Forced outage (%)	10	10	10	50	30	50	30		1
Planned outage (weeks per year)	4	4	4	2	6	2	6		1
Technical lifetime (years)	30	30	30	20	50	20	50		1,10
Construction time (years)	2	2	2	1,5	3	1,5	3	H	1,10
Space requirement (1000 m^2/MWe)	30	31	32	20	40	20	40		1
Additional data for non thermal plants									
Capacity factor (%), theoretical	90	90	90	70	100	70	100		1
Capacity factor (%), incl. outages	80	80	80	70	100	70	100		1
Ramping configurations									
Ramping (% per minute)									
Minimum load (% of full load)									
Warm start-up time (hours)									
Cold start-up time (hours)									
Environment									
PM 2.5 (gram per Nm^3)	-	-	-	-	-	-	-	B	6
SO_2 (degree of desulphuring, %)	-	-	-	-	-	-	-	B	6
NO_X (g per GJ fuel)	-	-	-	-	-	-	-	B	6
CH_4 (g per GJ fuel)	-	-	-	-	-	-	-	B	6
N_2O (g per GJ fuel)	-	-	-	-	-	-	-	B	6
Financial data									
Nominal investment (M$/MWe)	5.50	5.50	4.95	4.20	7.00	1.80	4.82	C,D,E,F	1,2,4,8,11
- of which equipment	60%	60%	60%	40%	70%	40%	70%		3
- of which installation	40%	40%	40%	30%	50%	30%	50%		3
Fixed O&M ($/MWe/year)	145,000	145,000	130,500	108,750	181,250	163,125	97,875	C,D,G	1,4,9,11
Variable O&M ($/MWh)	0.39	0.39	0.35	0.29	0.49	0.44	0.26	C,D	1,4
Start-up costs ($/MWe/start-up)	-	-	-	-	-	-	-		
Technology specific data									
Exploration costs (M$/MWe)	0.16	0.15	0.15	0.11	0.21	0.11	0.21		7
Confirmation costs (M$/MWe)	0.16	0.15	0.15	0.11	0.21	0.11	0.21		7

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1 MEMR Focus Group Discussions with various stakeholders for the purposes of updating the Technology Catalogue in 2023

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9 IRENA, 2023, Renewable Power Generation Costs in 2022

10 Moore, 2016, "Geothermal Power Generation: Developments and Innovation, chapter 18: Project permitting, finance, and economics for geothermal power

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Notes:

A The efficiency is the thermal efficiency - meaning the utilization of heat from the ground. Since the geothermal heat is renewable and considered free, then an increase in effciency will give a lower investment cost per MW. These smaller units are assumed to be binary units at medium source temperatures.

B Geothermal do emit H_2S. From Minister of Environment Regulation 21/2008 this shall be below 35 mg/Nm^3.

C Uncertainty (Upper/Lower) is estimated as +/- 25%.

D Investment cost are including Exploration and Confirmation costs (see under Technology specific data).

E Investment cost include the engineering, procurement and construction (EPC) cost. See description under Methodology.

F For 2020, uncertainty ranges are based on cost spans of various sources. For 2050, we combine the base uncertainity in 2020 with an additional uncertainty span based on learning rates varying between 10-15% and capacity deployment from Stated Policies and Sustainable Development scenarios separately.

G O&M includes costs related to the continous management of the geothermal site to maintain capacity and performance. Given costs is estimated for two sets of wells for makeup and reinjection over the 25-year life of the project to maintain performance.

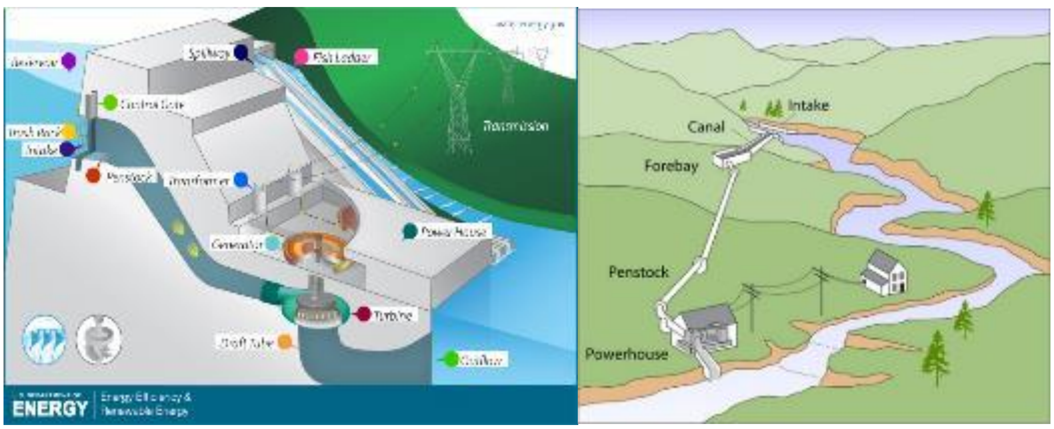
H Refers to construction of the steam cycle power plant itself. Preperation of the geothermal site includes surveying, exploration, drilling, resource confirmation, which can take 4-5 years in total.

2. Hydro Power Plant

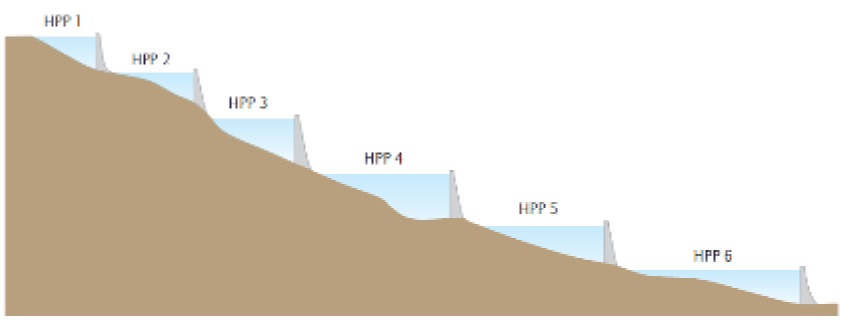
Brief technology description

There are three types of hydropower facilities:

- Run-of-river. A facility that channels flowing water from a river through a canal or penstock to spin a turbine. Typically, a run-of-river project will have little or no storage facility.
- Storage/reservoir. Uses a dam to store water in a reservoir. Electricity is produced by releasing water from the reservoir through a turbine, which activates a generator.
- Pumped-storage. Providing peak-load supply, harnessing water which is cycled between a lower and upper reservoir by pumps which use surplus energy from the system at times of low demand (this will be explained in Chapter 15).



Reservoir and run-of-river hydropower plants (ref. 15)



Cascading Systems (ref. 1)

Run-of-river and reservoir hydropower plants can be combined in cascading river systems and pumped storage plants can utilize the water storage of one or several reservoir hydropower plants. In Cascading systems, the energy output of a run-of-river hydropower plant could be regulated by an upstream reservoir hydropower plant, as in cascading hydropower schemes. A large reservoir in the upper catchment generally regulates outflows for several run-of-rivers or smaller reservoir plants downstream. This likely increases the yearly energy potential of downstream sites and enhances the value of the upper reservoir’s storage function. However, this also creates the dependence of downstream plants to the commitment of the upstream plants.

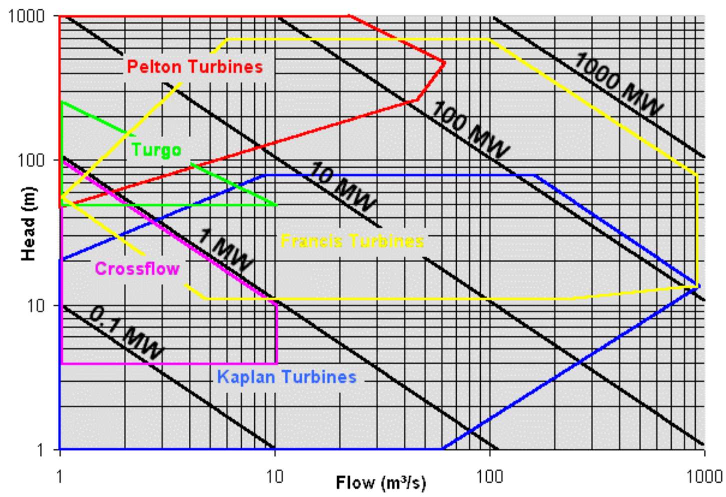
In Indonesia, big cascading systems can be found at the Citarum River and Brantas River basins in West and East Jawa respectively. There are three hydropower plants installed at Citarum River. They are, from upstream to downstream, Saguling (700 MW), Cirata (1008 MW) and Jatiluhur (150 MW) hydropower plants. At Brantas River, there are twelve hydropower plants in operation with a total capacity of 281 MW.

Hydropower systems can range from tens of Watts to hundreds of MW. A classification based on the size of hydropower plants in Indonesia is presented in the table below. However, there is no internationally recognized standard definition for hydropower sizes, so definitions can vary from one country to another.

Classification of hydro-power size (ref. 2)

Type	Capacity
Large hydro power	> 30 MW
Small hydropower	1 MW – 30 MW
Mini and micro hydropower	1 - 1000 kW

Large hydropower plants often have outputs of hundreds or even thousands of MW and use the energy in falling water from the reservoir to produce electricity using a variety of available turbine types (e.g. Pelton, Francis, Kaplan) depending on the characteristics of the river and installation capacity. Small, mini, micro and pico hydropower plants are run-of-river schemes. These types of hydropower use Cross-flow, Pelton, or Kaplan turbines. The selection of turbine type depends on the head and flow rate of the river.



Hydropower turbine application chart (ref. 3)

For high heads and small flows, Pelton turbines are used, in which water passes through nozzles and strikes spoon-shaped buckets arranged on the periphery of a wheel. A less efficient variant is the cross-flow turbine. These are action turbines, working only from the kinetic energy of the flow. Francis turbines are the most common type, as they accommodate a wide range of heads (20 m to 700 m), small to very large flows, a broad rate capacity and excellent hydraulic efficiency.

For low heads and large flows, Kaplan turbines, a propeller-type water turbine with adjustable blades, dominate. Kaplan and Francis turbines, like other propeller-type turbines, capture the kinetic energy and the pressure difference of the fluid between the entrance and exit of the turbine.

In 2022the total capacity of hydropower plants installed in Indonesia was 5.988 MW. At the same time, the total electricity produced from hydropower plants was 27.3 TWh. (*Ref. 4*) Hence, the average capacity factor of hydropower was around 52% across all types of plants. The capacity factor achieved by hydropower projects needs to be looked at differently compared to other renewable projects. It depends on the availability of water and also the purpose of the plants whether for meeting peak and/or base demand. The average capacity factor of hydropower in the period 2010-2022 has been 47% for large-scale plants and 52% for small-scale plants. There is significant variation between projects and across geographies with ranges from between 23% to 80% (global 5th and 95th percentile) in the same period (*Ref. 28*).

Indonesia has an abundance of hydropower resource potential. It is estimated that the untapped hydropower potential is about 94.5 GW (ref. 4). According to the same source, about 19.4 GW of the potential is classified as micro hydropower potential.

Hydro resources potential (from EBTKE)

No	Island	Hydro (GW)	Micro Hydro (GW)
1	Sumatera	15.60	5.73
2	Jawa	4.20	2.91
3	Kalimantan	21.60	8.10
4	Sulawesi	10.20	1.67
5	Bali and Nusa Tenggara	0.62	0.14
6	Maluku	0.43	0.21
7	Papua	22.35	0.62
Total		75.00	19.37

Input

The falling water from either reservoir or run-of-river has a certain head and flow rate.

Output

Electricity.

Typical capacities

Hydropower systems can range from tens of Watt to hundreds of MW. Currently up to 900 MW per unit (ref. 16). The largest unit capacity of hydropower plant turbine which has ever been installed in Indonesia is 175 MW at PLTA Saguling, West Java.

Ramping configurations

Hydropower helps to maintain the power frequency by continuous modulation of active power, and to meet moment-to-moment fluctuations in power requirements. It offers rapid ramp rates and usually very large ramp ranges, making it very efficient to follow steep load variations or intermittent power supply of renewable energy such as wind and solar power plants.

Advantages/disadvantages

Advantages:

- Hydropower is fueled by water, so it's a clean fuel source. Hydropower doesn't pollute the air.
- Hydropower is a domestic source of energy, produced locally in Indonesia.
- Hydropower relies on the water cycle, which is driven by the sun, thus it's a renewable power source.
- Hydropower is generally available as needed; engineers can control the flow of water through the turbines to produce electricity on demand.

- Hydropower facilities have a very long service life, which can be extended indefinitely, and further improved. Some operating facilities in certain countries are 100 years and older. This makes for long-lasting, affordable electricity.
- Hydropower plants provide benefits in addition to clean electricity. Impoundment hydropower creates reservoirs that offer a variety of recreational opportunities, notably fishing, swimming, and boating. Other benefits may include water supply, irrigation and flood control.

Disadvantages:
- Fish populations can be impacted if fish cannot migrate upstream past impoundment dams to spawning grounds or if they cannot migrate downstream to the ocean.
- Hydropower can impact water quality and flow. Hydropower plants can cause low dissolved oxygen levels in the water, a problem that is harmful to riverbank habitats.
- Hydropower plants can be impacted by drought. When water is not available, the hydropower plants cannot produce electricity.
- Hydropower plants can be impacted by sedimentation. Sedimentation affects the safety of dams and reduces energy production, storage, discharge capacity and flood attenuation capabilities. It increases loads on the dam and gates, damages mechanical equipment and creates a wide range of environmental impacts.
- New hydropower facilities impact the local environment and may compete with other uses for the land. Those alternative uses may be more highly valued than electricity generation. Humans, flora, and fauna may lose their natural habitat. Local cultures and historical sites may be impinged upon.
- If the catchment area is not managed properly the water source can be significantly lower than expected.

Environment

Environmental issues identified in the development of hydropower include:
- Safety issues:
  Hydropower is very safe today. Losses of life caused by dam failure have been very rare in the last 30 years. The population at risk has been significantly reduced through the routing and mitigation of extreme flood events.
- Water use and water quality impacts:
  The impact of hydropower plants on water quality is very site-specific and depends on the type of plant, how it is operated and the water quality before it reaches the plant. Dissolved oxygen (DO) levels are an important aspect of reservoir water quality. Large, deep reservoirs may have reduced DO levels in bottom waters, where watersheds yield moderate to heavy amounts of organic sediments.
- Impacts on migratory species and biodiversity:
  Older dams with hydropower facilities were often developed without due consideration for migrating fish. Many of these older plants have been refurbished to allow both upstream and downstream migration capability.
- Implementing hydropower projects in areas with low or no anthropogenic activity:
  In areas with low or no anthropogenic activity, the primary goal is to minimize the impacts on the environment. One approach is to keep the impact restricted to the plant site, with minimum interference over forest domains at dams and reservoir areas, e.g. by avoiding the development of villages or cities after the construction periods.
- Reservoir sedimentation and debris:
  This may change the overall geomorphology of the river and affect the reservoir, the dam/power plant and the downstream environment. Reservoir storage capacity can be reduced, depending on the volume of sediment carried by the river.
- Lifecycle greenhouse gas emissions.

Life-cycle CO_2 emissions from hydropower originate from construction, operation and maintenance, and dismantling. Possible emissions from land-use-related net changes in carbon stocks and land management impacts are very small.

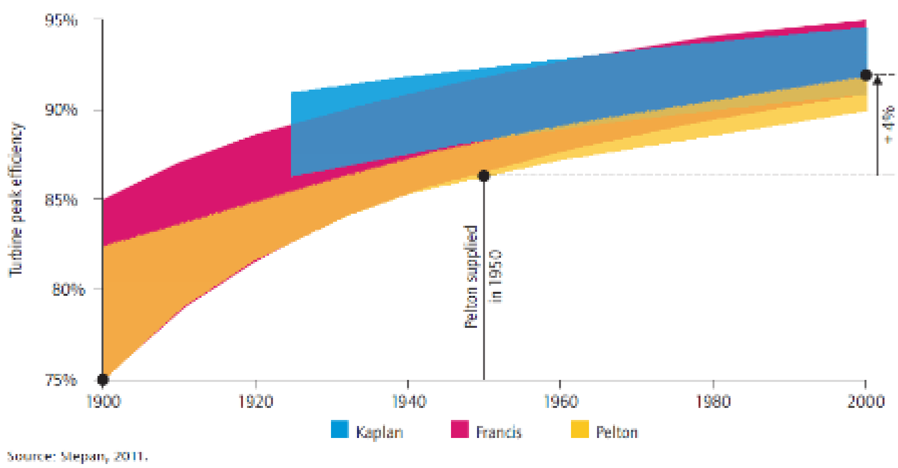
Employment

Generally, a new large hydropower plant (110 MW) project will provide around 2,000 – 3,000 local jobs during the construction phase. The kind of jobs expected are technicians, welders, joineries, carpenters, porters, project accountants, electrical and mechanical engineers, cooks, cleaners, masons, security guards and many others. Of those, about 150 - 200 of them will continue to work at the facility. (ref. 19)

Research and development

Hydropower is a very mature and well-known technology (category 4). While hydropower is the most efficient power generation technology, with a high energy payback ratio and conversion efficiency, there are still many areas where small but important improvements in technological development are needed.

- Improvements in turbines:
  The hydraulic efficiency of hydropower turbines has shown a gradual increase over the years: modern equipment reaches 90% to 95%. This is the case for both new turbines and the replacement of existing turbines (subject to physical limitations).

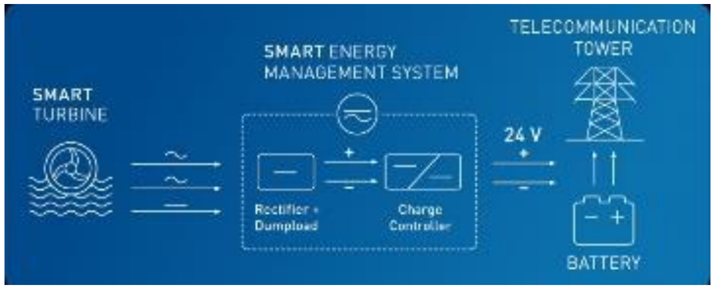


Improvement of hydraulic performance over time (ref. 8)

Some improvements aim directly at reducing the environmental impacts of hydropower by developing

  - Fish-friendly turbines
  - Aerating turbines
  - Oil-free turbines

- Hydrokinetic turbines:
  Kinetic flow turbines for use in canals, pipes and rivers. In-stream flow turbines, sometimes referred to as hydrokinetic turbines, rely primarily on the conversion of energy from free-flowing water, rather than from hydraulic head created by dams or control structures. Most of these underwater devices have horizontal axis turbines, with fixed or variable pitch blades. In Indonesia, a collaboration among PT Bima Green Energy, PT Telkomsel Indonesia and Smart Hydro Power GmBH, a German company, has installed two units of 5 kW pico hydropower with the hydrokinetic turbine in Tabang, East Kalimantan to power a telecommunication tower located at a remote area which is not connected to the grid.



Pico hydropower with hydrokinetic turbine for remote telecommunication towers (ref. 17)

- Bulb (Tubular) turbines:
  Nowadays, very low heads can be used for power generation in an economically feasible way. Bulb turbines are efficient solutions for low heads up to 30 m. The term "Bulb" describes the shape of the upstream watertight casing which contains a generator located on a horizontal axis. The generator is driven by a variable-pitch propeller (or Kaplan turbine) located on the downstream end of the bulb.
- Improvements in civil works:
  The cost of civil works associated with new hydropower project construction can be up to 70% of the total project cost, so improved methods, technologies and materials for planning, design and construction have considerable potential (ref. 14). A roller-compacted concrete (RCC) dam is built using much drier concrete than traditional concrete gravity dams, allowing speedier and lower cost construction.
- Upgrade or redevelop old plants to increase efficiency and environmental performance.
- Add hydropower plant units to existing dams or water flows.

Investment cost estimation
The overnight capital cost of hydropower plants strongly depends on the site where the plant is located and observed costs therefore have very large variations. While hydropower benefits from economy of scale as most generation technologies, the best and most accessible sites for large hydro might be already exploited; in some cases, run of river (small size) hydro is built at a lower cost.
In Indonesia, the largest part of the latest PPA auctions involved the construction of small-to-medium hydropower plants. For large hydro, data is scarce and so is the standard deviation from the average cost. Project data from IRENA shows that – on average – overnight costs for hydropower plants tend to be rather stable over the years. The technology is well-established, and the limited technological advancements might be offset by higher development costs (e.g. stricter environmental assessments). Given these premises, this catalogue still considers economy of scale to be the most relevant factor in determining the cost of a hydropower plant.

Overview of investment cost examples:

Investment costs [$MUSD_{2022}$/ MW]		**2020**	**2023**	**2030**	**2050**
Catalogues	**New Catalogue (2023)**		**2.20** (large hydro) **2.50** (small hydro) **2.70** (micro hydro)	**2.11** (large hydro) **2.40** (small hydro) **2.59** (micro hydro)	**1.96** (large hydro) **2.23** (small hydro) **2.40** (micro hydro)
	Existing Catalogue (2020)		2.37 (large hydro) 2.61 (small hydro) 3.08 (micro hydro)	2.28 (large hydro) 2.51 (small hydro) 2.95 (micro hydro)	2.22 (large hydro) 2.32 (small hydro) 2.74 (micro hydro)
Indonesian data	PPA data of specific projects[1]	2.56 (large hydro) 2.09 (small hydro) 2.43 (mini hydro)			

	MEMR FGDs 2023[2]	1,0 -3.86 (hydro Run-of-River)			
		2.26-4.65 (large hydro)	2.22 (large hydro)		
		0.92- 4.41 (mini hydro)	1.48 (mini hydro)		
International data	IRENA[3]	1.61-2.07 (large hydro) 2.35-2.86 (small hydro)	2.30-2.88 (large hydro) 2.28-2.73 (small hydro)		
	NREL[4]		2.8-6.8		2.7-6.8
Projection	Development curve – cost trend [%]		100%	96%	89%

[1]PPA results signed in 2018 with COD 2018-2022 as summarized in the presentation by Ignasius Jonan in "Renewable Energy for Sustainable Development" (Bali, 12 Sept 2018)
[2]MEMR Focus Group Discussions with various stakeholders for the purposes of updating the Technology Catalogue in 2023
[3]IRENA, Renewable Power Generation Costs in 2022. 2020 values reflect 2018-2020 global weighted average
[4]NREL ATB. There is very large variation depending on size and type of site, which makes it difficult to compare directly. Only limited cost development is expected in this reference.

Examples of current projects

Large Scale Hydro Power Plant: Batang Toru Hydro Power Plant (Ref. 21)

The construction of Batang Toru hydroelectric power plant (PLTA) with a capacity of 4 × 127.5 MW is located in the Batang Toru River, Sipirok Village, South Tapanuli Regency, North Sumatra Province. This project uses the concept of a run-off hydro system and is land-efficient. The land area is only 122 ha with a building area of 56 ha and a maximum flooded area of 66 ha. No humans are living in the flooded area, so there is no need for relocation. This project contributes around 15% of North Sumatra's peak load. The construction phase began in 2017. The operational target (Commercial Operation Date) of the Batang Toru Hydroelectric Power Plant is in 2022. In terms of operating patterns, this project is a peaker type. This plant is owned by PT Pembangkitan Jawa Bali Investasi. The total investment cost for this project is 1.68 billion USD. After granted by the Minister of Energy and Mineral Resources, the electricity selling price of Batang Toru Hydroelectric Plant is 12.8574 US cents/kWh. According to the company, the project will recruit about 2000 workers during construction.

Comparison between Capacity, Body of Water Area, and Population Relocation (Ref. 21)

Hydropower plant	Capacity (MW)	Body of Water Area (Ha)	Population Relocation
Batangtoru	510.00	66.70	0.00
Jatiluhur	187.50	8,300.00	5,002.00
Saguling	797.36	5,300.00	10,000.00
Cirata	1,008.00	6,200.00	10,000.00

Medium Scale Hydro Power Plant: Rajamandala Hydro Power Plant (Ref. 22)

Rajamandala hydroelectric power plant (HEPP) is using the available head from Saguling HEPP (4 x 175 MW) before the water reaches Cirata Dam, West Jawa. This means, the power plant can generate additional electricity from the existing cascading system without adding pollution to the environment. This plant has a capacity of 47 MW and has an operating pattern which follows the operation pattern of the Saguling HEPP. This project is owned by PT Rajamandala Electric Power. Last year, this plant began to operate commercially. The electricity produced is sold to PT. PLN (Persero) under PPA (Power Purchase Agreement) at 8.6616 US cents/kWh through 8 km of 150 KV grid connected to existing Cianjur – Cigareleng transmission line for 30 years for 30 years. PLTA Rajamandala utilizes the Citarum River current and uses the Francis Vertical Kaplan turbine. The water discharge is 168 cubic meters (m^3) with a gross head of 34 meters. PLTA Rajamandala will produce 181 GWh of electricity per year with a capacity factor of 44%. The investment cost of PLTA Rajamandala reaches US $ 150 million. The project offers 1,200 job opportunities for local workers.

Rajamandala HEPP in West Jawa (Ref. 23)

Small Scale Hydro Power Plant: Bakal Semarak Hydro Power Plant (Ref. 24)

The small hydro Bakal Marak power plant at Sidikalang, North Sumatera, has a capacity of 5 MW. The investment cost of this project is estimated at 125.6 billion rupiahs or equivalent to 8.66 million USD. PLN has agreed to buy the electricity produced at US cents7.89 per kWh under a PPA contract for 30 years. This project is scheduled to be online this year. PT Semarak Kita Bersama owns this project.

Electric Hydro Power Plants (ref 25)

Cirata II Hydro-Electric Power Plant: 500 MW

The Cirata II Hydro-electric Plant, located in West Java, has an installed capacity of 4 x 125 MW which, at the time of commissioning, was the largest Hydro-Electric Power Plant in Indonesia. The electromechanical equipment included vertical shaft Francis-type turbines, 140 MVA Generators, 3-winding 280 MVA generator transformers and connections to an existing 500 kV substation

Asahan 3 Hydro-Electric Power Plant: 174 MW

The Asahan 3 Hydro Power Plant, in North Sumatra, comprises 2 x 87 MW generator sets driven by vertical shaft Francis-type turbines. The 2 x 97 MVA generator transformers connect to a 150 kV substation. The substation and outgoing 64 km of 150 kV overhead lines formed part of the contract.

The run of the river scheme includes a concrete weir, headrace tunnel, penstocks, an underground powerhouse and a tailrace.

Simanggo 2 Hydro-Electric Power Plant: 86 MW

Simanggo-2 Hydro-Electric Power Plant is located in Humbang Hasundutan Regency, North Sumatera with a potential installed capacity of 86 MW. The generated power will be connected to the North Sumatera grid subsystem.

Masang 2 Hydro-Electric Power Plant: 55 MW
Masang-2 Hydro-Electric Power Plant, located in Agam Regency, West Sumatera, has a potential installed capacity of 55 MW. The generated power will be connected to the West Sumatera grid subsystem.

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28. IRENA, 2023, *Renewable Power Generation Costs in 2022*

Datasheets

The following pages contain the datasheets of the technology. All costs are stated in U.S. dollars (USD), price year 2022. The uncertainty is related to the specific parameters and cannot be read vertically – meaning a product with e.g. lower efficiency does not have a lower price.

Technology

Technology	Hydro power plant - large system								
	2023	2030	2050	Uncertainty (2023)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	60	60	60	17	175	100	2000	G	1,8
Generating capacity for total power plant (MWe)	200	200	200	68	700	100	2000	G	1,8
Electricity efficiency, net (%), name plate	95	95	95	85	97	85	97	A	7
Electricity efficiency, net (%), annual average	95	95	95	85	97	85	97	A	7
Forced outage (%)	4	4	4	2	10	2	10		1
Planned outage (weeks per year)	6	6	6	3	10	3	10		1
Technical lifetime (years)	50	50	50	40	90	40	90	B	1
Construction time (years)	4	4	4	2	6	2	6		1
Space requirement (1000 m^2/MWe)	62	62	62	47	78	47	78	C	1
Additional data for non thermal plants									
Capacity factor (%), theoretical	55	55	55	20	95	20	95	G	1,2,11
Capacity factor (%), incl. outages	51	51	51	20	95	20	95	G	1,2,11
Ramping configurations									
Ramping (% per minute)	30	30	30	10	86	10	90		3
Minimum load (% of full load)	0	0	0	0	0	0	0		3
Warm start-up time (hours)	0	0	0	0	1	0	0.3		3
Cold start-up time (hours)	2	2	0	0	7	0	7		3
Environment									
PM 2.5 (gram per Nm^3)	0	0	0						
SO_2 (degree of desulphuring, %)	0	0	0						
NO_X (g per GJ fuel)	0	0	0						
CH_4 (g per GJ fuel)	0	0	0						
N_2O (g per GJ fuel)	0	0	0						
Financial data									
Nominal investment (M$/MWe)	2.20	2.11	1.96	1.65	2.75	1.47	2.45	D,E,F	1,4,5,6
- of which equipment	30%	30%	30%	20%	50%	20%	50%	H	6,10
- of which installation	70%	70%	70%	50%	80%	50%	80%	H	6,10
Fixed O&M ($/MWe/year)	43,000	41,000	38,000	32,250	53,750	28,500	47,500	C	1,4,5,6
Variable O&M ($/MWh)	0.74	0.71	0.66	0.56	0.93	0.50	0.83	C	1,5
Start-up costs ($/MWe/start-up)	-	-	-	-	-	-	-		

References:

1 MEMR Focus Group Discussions with various stakeholders for the purposes of updating the Technology Catalogue in 2023

2 Branche, 2011, "Hydropower: the strongest performer in the CDM process, reflecting high quality of hydro in comparison to other renewable energy sources".

3 Eurelectric, 2015, "Hydropower - Supporting a power system in transition".

4 IRENA, 2023, Renewable Power Generation Costs in 2022

5 Learning curve approach for the development of financial parameters.

6 IEA, 2021, Hydropower Special Market Report

7 Stepan, 2011, Workshop on Rehabilitation of Hydropower, "The 3-Phase Approach".

8 Prayogo, 2003, "Teknologi Mikrohidro dalam Pemanfaatan Sumber Daya Air untuk Menunjang Pembangunan Pedesaan. Semiloka Produk-produk Penelitian Departement Kim

9 General Electric, www.gerenewableenergy.com, Accessed: 20th July 2017

10 ASEAN, 2016, "Levelised cost of electricity of selected renewable technologies in the ASEAN member states".

11 MEMR, 2023, "Handbook of Energy & Economic Statistics of Indonesia 2022"

Notes:

A This is the efficiency of the utilization of the waters potential energy. This can not be compared with a thermal power plant that have to pay for its fuel.

B Hydro power plants can have a very long lifetime is operated and mainted properly. Hover Dam in USA is almost 100 years old.

C Uncertainty (Upper/Lower) is estimated as +/- 25%.

D Numbers are very site sensitive. There will be an improvement by learning curve development, but this improvement will equalized because the best locations will be utilized first. The investment largely depends on civil work.

E Investment cost include the engineering, procurement and construction (EPC) cost. See description under Methodology.

F For 2020, uncertainty ranges are based on cost spans of various sources. For 2050, we combine the base uncertainity in 2020 with an additional uncertainty span based on learning rates variying between 10-15% and capacity deployment from Stated Policies and Sustainable Development scenarios separately.

G Based on data collection from Indonesian projects

H For large hydropower plants the civil works and earthworks to establish tunneling and dams are often the biggest share of the costs (around 50% according to Ref 6). These costs are included as instalaltion costs as described in the overall methodology.

Technology

Technology	Hydro power plant - Medium/small system								
	2023	2030	2050	Uncertainty (2023)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	5	5	5	1	22	1	50	E	2,9
Generating capacity for total power plant (MWe)	11	11	11	1	100	20	100	E	2,9
Electricity efficiency, net (%), name plate	95	95	95	85	97	85	97	A	1
Electricity efficiency, net (%), annual average	95	95	95	85	97	85	97	A	1
Forced outage (%)	4	4	4	2	10	2	10		1
Planned outage (weeks per year)	6	6	6	3	10	3	10		1
Technical lifetime (years)	50	50	50	40	90	40	90		1
Construction time (years)	3	3	3	2	6	2	6		1
Space requirement (1000 m^2/MWe)	14	14	14	11	18	11	18	B	
Additional data for non thermal plants									
Capacity factor (%), theoretical	55	55	55	20	95	20	95		8,9
Capacity factor (%), incl. outages	51	51	51	20	95	20	95		8,9
Ramping configurations									
Ramping (% per minute)	50	50	50	30	100	30	100		3
Minimum load (% of full load)	0	0	0	0	0	0	0		3
Warm start-up time (hours)	0	0	0	0	0	0	0.3		3
Cold start-up time (hours)	0	0	0	0	0	0	0.3		3
Environment									
PM 2.5 (gram per Nm^3)	0	0	0						
SO_2 (degree of desulphuring, %)	0	0	0						
NO_X (g per GJ fuel)	0	0	0						
CH_4 (g per GJ fuel)	0	0	0						
N_2O (g per GJ fuel)	0	0	0						
Financial data									
Nominal investment (M$/MWe)	2.50	2.40	2.23	1.88	3.13	1.67	2.78	C,D	5,6,9
- of which equipment	40%	40%	40%	20%	50%	20%	50%	F	6
- of which installation	60%	60%	60%	50%	80%	50%	80%	F	6
Fixed O&M ($/MWe/year)	47,800	45,800	42,500	35,850	59,750	31,875	53,125		4,5,6,9
Variable O&M ($/MWh)	0.57	0.55	0.51	0.43	0.71	0.38	0.64	B	1
Start-up costs ($/MWe/start-up)	-	-	-	-	-	-	-		

References:
1 Stepan, 2011, Workshop on Rehabilitation of Hydropower, "The 3-Phase Approach".
2 Prayogo, 2003, "Teknologi Mikrohidro dalam Pemanfaatan Sumber Daya Air untuk Menunjang Pembangunan Pedesaan. Semiloka Produk-produk Penelitian Departement
3 Eurelectric, 2015, "Hydropower - Supporting a power system in transition".
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5 IRENA, 2023, Renewable Power Generation Costs in 2022
6 IEA, 2021, Hydropower Special Market Report
7 ASEAN, 2019, "Levelised cost of electricity of selected renewable technologies in the ASEAN member states".
8 Branche, 2011, "Hydropower: the strongest performer in the CDM process, reflecting high quality of hydro in comparison to other renewable energy sources".
9 MEMR Focus Group Discussions with various stakeholders for the purposes of updating the Technology Catalogue in 2023

Notes:

A This is the efficiency of the utilization of the waters potential energy. This can not be compared with a thermal power plant that have to pay for its fuel.
B Uncertainty (Upper/Lower) is estimated as +/- 25%.
C Numbers are very site sensitive. There will be an improvement by learning curve development, but this improvement will equalized because the best locations will be utilized first. The investment largely depends on civil work.
D Investment cost include the engineering, procurement and construction (EPC) cost. See description under Methodology.
E Based on data collection from Indonesian projects
F For hydropower plants the civil works and earthworks to are often a significant share of the costs which are included as installation according to the methodology.

Technology

Technology	Hydro power plant - Mini/micro system								
	2023	2030	2050	Uncertainty (2023)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	0.5	0.5	0.5	0.1	1.0	0.1	1.0	G	1,8
Generating capacity for total power plant (MWe)	0.69	0.69	0.69	0.10	1.30	0.10	1.30	G	1,8
Electricity efficiency, net (%), name plate	80	80	80	70	90	70	90	A	7
Electricity efficiency, net (%), annual average	80	80	80	70	90	70	90	A	7
Forced outage (%)	4	4	4	2	10	2	10		
Planned outage (weeks per year)	6	6	6	3	10	3	10		
Technical lifetime (years)	50	50	50	40	90	40	90	B	
Construction time (years)	2	2	2	1.5	3	1.5	3		
Space requirement (1000 m^2/MWe)									
Additional data for non thermal plants									
Capacity factor (%), theoretical	55	55	55	20	95	20	95		1,2
Capacity factor (%), incl. outages	51	51	51	20	95	20	95		1,2
Ramping configurations									
Ramping (% per minute)	-	-	-	-	-	-	-	E	
Minimum load (% of full load)	-	-	-	-	-	-	-	E	
Warm start-up time (hours)	-	-	-	-	-	-	-	E	
Cold start-up time (hours)	-	-	-	-	-	-	-	E	
Environment									
PM 2.5 (gram per Nm^3)	0	0	0						
SO_2 (degree of desulphuring, %)	0	0	0						
NO_X (g per GJ fuel)	0	0	0						
CH_4 (g per GJ fuel)	0	0	0						
N_2O (g per GJ fuel)	0	0	0						
Financial data									
Nominal investment (M$/MWe)	2.70	2.59	2.40	2.03	3.38	1.80	3.00	D,F	1,4,5
- of which equipment	40%	40%	40%	20%	50%	20%	50%		6
- of which installation	60%	60%	60%	50%	80%	50%	80%		6
Fixed O&M ($/MWe/year)	60,400	58,000	54,000	45,300	75,500	40,500	67,500	C	1,4,5
Variable O&M ($/MWh)	0.57	0.55	0.51	0.43	0.71	0.38	0.63	C	1,5
Start-up costs ($/MWe/start-up)	-	-	-	-	-	-	-		

References:

1 MEMR Focus Group Discussions with various stakeholders for the purposes of updating the Technology Catalogue in 2023
2 Branche, 2011, "Hydropower: the strongest performer in the CDM process, reflecting high quality of hydro in comparison to other renewable energy sources".
3 Eurelectric, 2015, "Hydropower - Supporting a power system in transition".
4 IRENA, 2023, Renewable Power Generation Costs in 2022
5 Learning curve approach for the development of financial parameters.
6 IEA, 2021, Hydropower Special Market Report
7 IFC, 2015, "Hydroelectric Power - A guide for developers and investers".
8 Prayogo, 2003, "Teknologi Mikrohidro dalam Pemanfaatan Sumber Daya Air untuk Menunjang Pembangunan Pedesaan. Semiloka Produk-produk Penelitian Departement Kimpraswill Makassar".

Notes:

A This is the efficiency of the utilization of the waters potential energy. This can not be compared with a thermal power plant that have to pay for its fuel.
B Hydro power plants can have a very long lifetime is operated and mainted properbly. Hover Dam in USA is almost 100 years old.
C Uncertainty (Upper/Lower) is estimated as +/- 25%.
D Numbers are very site sensitive and the uncertainty can be even more extreme than listed. There will be an improvement by learning curve development, but this improvement will equalized because the best locations will be utilized first. The investment largely depends on civil work.
E It is assumed that micro and mini hydro do not have a reservior (run-of-river) and therefor is not capable of regulation. The possibility of a turbine bypass could give the possibility of down regulation.
F Investment cost include the engineering, procurement and construction (EPC) cost. See description under Methodology.
G Based on data collection from Indonesian projects

3. Solar Photovoltaics

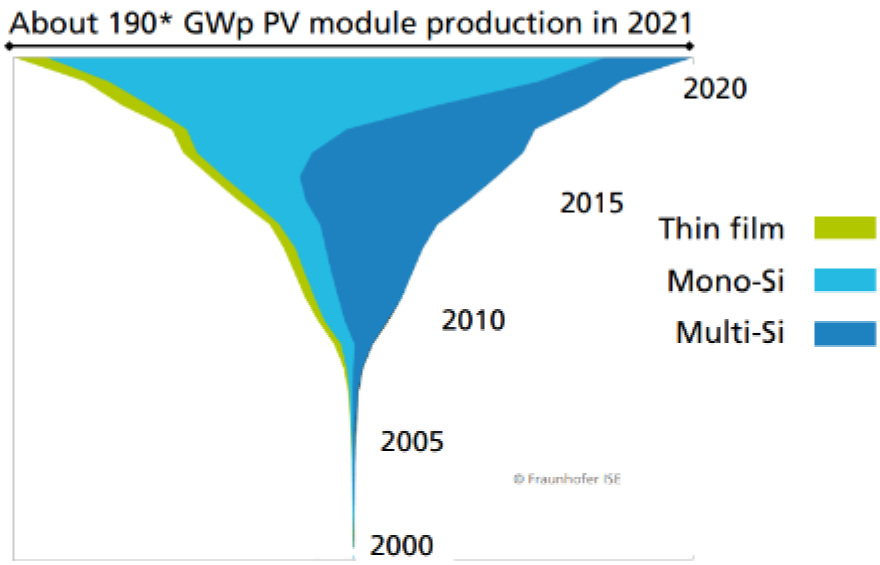
Brief technology description

A solar cell is a semiconductor component that generates electricity when exposed to light. For practical reasons, several solar cells are typically interconnected and laminated to (or deposited on) a glass pane to obtain a mechanical ridged and weathering-protected solar module. The photovoltaic (PV) modules are typically 1-2 m^2 in size and have a power density in the range of 100-210 Watt-peak pr. m^2 (Wp/m^2). They are sold with a product guarantee of typically two to five years, a power warranty of a minimum of 25 years and an expected lifetime of around 27 years.

PV modules are characterised according to the type of absorber material used:

- Crystalline silicon (c-Si); the most widely used substrate material is made from purified solar-grade silicon and comes in the form of mono-crystalline (sc-Si) or multi-crystalline (mc-Si) silicon wafers. Currently, more than 95 pct. of all PV modules are wafer-based divided between multi- and mono-crystalline. This technology platform is expected to dominate the world market for decades due to significant cost and performance advantages (ref. 1).
- Passivated Emitter and Rear Cell (PERC); this is a more recent advancement in solar cell technology where monocrystalline silicon cell architecture is modified to have a passivation layer at the back of the cells. The additional layer allows for the solar radiation, that has not been absorbed, to reflect and allow for a second attempt for absorption by the cell. This layer improves the cell efficiency and reduces cell heating.
- Tandem/hybrid cells; Tandem solar cells are stacks of individual cells, one on top of the other, that each selectively convert a specific band of light into electrical energy, leaving the remaining light to be absorbed and converted to electricity in the cell below.
- Thin film solar cells; where the absorber can be an amorphous/microcrystalline layer of silicon (a-Si/μc-Si), Cadmium telluride (CdTe) or Copper Indium Gallium (di)Selenide (CIGS). These semiconductor materials are deposited on the top cover glass of the solar module in a micrometre-thin layer. Tandem junction and triple junction thin film modules are commercially available. In these modules, several layers are deposited on top of each other to increase the efficiency (ref. 1).
- Monolithic III-V solar cells; that are made from compounds of group III and group V elements (Ga, As, In and P), often deposited on a Ge substrate. These materials can be used to manufacture highly efficient multi-junction solar cells that are mainly used for space applications or in Concentrated Photovoltaic (CPV) systems (ref. 1).
- Perovskite material PV cells; Perovskite solar cells are in principle a Dye Sensitized solar cell with an organo-metal salt applied as the absorber material. Perovskites can also be used as an absorber in modified (hybrid) organic/polymer solar cells. The potential to apply perovskite solar cells in a multi-stacked cell on e.g. a traditional c-Si device provides interesting opportunities (ref. 1).

Different sources have estimated a total PV module production between 183 and 190 GWp for the year 2021. As illustrated in the figure below, the PV market was dominated by c-Si modules, accounting for nearly 95% of the total production. The production of sc-Si has been increasing in recent years, capturing more than 80% of the PV module market in 2021. Thin film production, on the other hand, comprised about 5% of the PV module production in 2021. Among the 10 GW of thin film produced in 2021, more than 80% consisted of CdTe. whereas less than 500 MW consisted of CIGS thin film modules (ref. 20).



Worldwide annual PV module production per technology in GWp (ref 20)

The encapsulation of cells into a PV module has undergone several changes over the last few years. Whereas the front protection is still made by a 2.2 – 3.2 mm thick antireflective coated semi-toughened microstructure glass, more and more modules have the back-sheet polymer foil replaced by another glass pane, whereby a more mechanically rigid and better-protected structure is obtained. This also opens for an optional elimination of the aluminium frame. Additionally, more transparent encapsulation materials known as polyolefins are now in use and anti-soiling surface nano-coatings have been introduced (ref. 23, ref. 24).

One of the emerging trends in the solar PV space is innovative advancements of PV module technologies (ref.7):

- Bifacial solar cells: Bifacial cells can generate electricity not only from sunlight received on their front, but also from reflected sunlight received on the reverse side of the cell. This technology has received a boost due to the development of PERC cell architecture. Bifacial operation with PERC can potentially increase cell efficiency by 5-20%.
- Multi-busbars: Busbars are thin metal strips on the front and back of solar cells that facilitate the conduction of DC current. While older designs have only 2 busbars on solar cells, recent advancements have led to solar cells with 3 or more, thinner busbars. These allow higher efficiencies, reduced resistance losses, and overall lower costs.
- Solar shingles: This development is towards designing panels that look like conventional roofing materials while still being able to produce enough electricity.

Grid-connected PV

In addition to PV modules, a grid-connected PV system also includes a Balance of System (BOS) consisting of a mounting system, dc-to-ac inverter(s), cables, combiner boxes, optimizers, monitoring/surveillance equipment and for larger PV power plants also transformer(-s). In 2021, the PV module itself accounted for less than 50% of the total system costs (and this share is dropping fast); inverters accounted for around 3-8%.

Solar PV plants can be installed and connected to the grid at the transmission or distribution level, or they can satisfy consumption locally on distributed level and off-grid PV. In 2021, the highest capacity of PV installations is utility-scale, but the market share of distributed and off-grid PV is rising.

Off-grid PV

Off-grid PV systems are autonomous systems which without being connected to the utility grid serve the electricity demand, usually of a remote or a rural area, by generating and storing the electricity independently. These versatile systems can be used to serve the electricity demand of small residential houses to larger communities in distant villages, and provide power for schools, hospitals, communication centres in rural locations, and emergency shelters. Off-grid systems, which can be installed either as rooftop or ground systems, must be equipped with an energy storage system, e.g. a battery, to benefit from the major part of the production, since the system is not connected to the grid. When the power generated by the rooftop is not used, the excess power will charge the battery until full. The battery power will be used later on when there is no sun or when the electricity supply from the PV plant is intermittent due to external factors like night-time, cloud cover, or others.

Utility Scale PV

Utility-scale PV is a large-scale, grid-connected photovoltaic system which utilizes arrays of identical electricity-generating PV modules that are mounted on the ground to capture the available solar irradiation and generate electricity in the megawatt range. These arrays of PV modules in the utility-scale PV systems are usually arranged in rows, inclined at an optimum tilt angle, and separated by a minimum interrow spacing to minimize the irradiation losses caused by self-shading. The determinants of the optimal tilt angle and interrow spacing are usually the solar window which depends on the latitude of the installation location, the solar panel's setup on its mounting structure, and the space restrictions for the O&M. As a rule of thumb, the tilt angle relative to the ground is recommended to be equal to the latitude of the project site. However, as a dust mitigation measure, a minimum angle of 10^{o} to 15^{o} is advisable in the tropical zones. Similarly, for latitudes greater than 30^{o}, the panel tilt is recommended to be 5^{o} - 20^{o} less than the project's latitude (ref 22).

Based on RUPTL 2021 – 2030[3], Indonesia has the potential to generate 208 GWe from utility-scale PV plants (ref 16). By 2030, Indonesia plans to develop a 3,236 MW grid-connected solar plant which will account for 69% of the total installed capacity of PV in the country (ref 17).

Rooftop PV

A rooftop photovoltaic power station, or rooftop PV system, is a photovoltaic system that has its electricity-generating solar panels mounted on the rooftop of a residential or commercial building or a structure such as parking facilities[4]. Such systems are often designed to the available roof area and for a high self-consumption. Rooftop-mounted systems are smaller than ground-mounted photovoltaic power stations (utility-scale PV) with capacities in the few to hundreds kilowatt range.

Rooftop PV systems can be either on-grid or off-grid systems. On-grid systems can, if the system is well designed, supply electricity without using power from the grid and feed excess power to the grid, potentially generating revenues by utilizing the utility’s net metering facility if such exists.

By the end of 2022, there were an estimated total of 6,461 rooftop solar pv installations totalling 77.6 MWp. Based on RUPTL 2021-2030’s solar development plan, Indonesia is expected to develop a total of 4,680 MW of solar PV power plants, by 2030. About 9% of these solar PV plants are rooftop PV installations.

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[3] RUPTL 2021-2030 is PLN Indonesia's Electricity Supply Business Plan from 2021 to 2030. PLN is state-owned electricity company of Indonesia.

[4] In December 2022, The French parliament has approved a new measure to make it mandatory for parking lots to include solar if their surface area is more than 1,500 square meters. As a result, more than 400 spaces have to comply in 2026.

Industrial PV and residential PV

The solar panels used in commercial and industrial-scale installations are larger than residential panels. The typical commercial or industrial solar installation uses 96-cell or greater solar panels, meaning each panel is made of 96 or more individual solar photovoltaic cells. While a typical residential solar panel will have 60 or 72 cells. Commercial and industrial solar systems include intricate racking systems to elevate and tilt the panels. Some commercial panel arrays even use racking with tracking capabilities, allowing the direction panels face to change and increase the amount of direct sunlight the panels receive.

Industrial PV and residential PV can be used both on-grid and off-grid. An industrial solar system can be up to several MW in size, depending on the amount of electricity the facility needs, while the peak capacity of a residential PV plant often is in the 1–10-kilowatt range, depending on if it is for a single-family or multi-family household. Both types may deliver non-self-consumed power to a transformer in the low-voltage distribution grid.

Floating PV

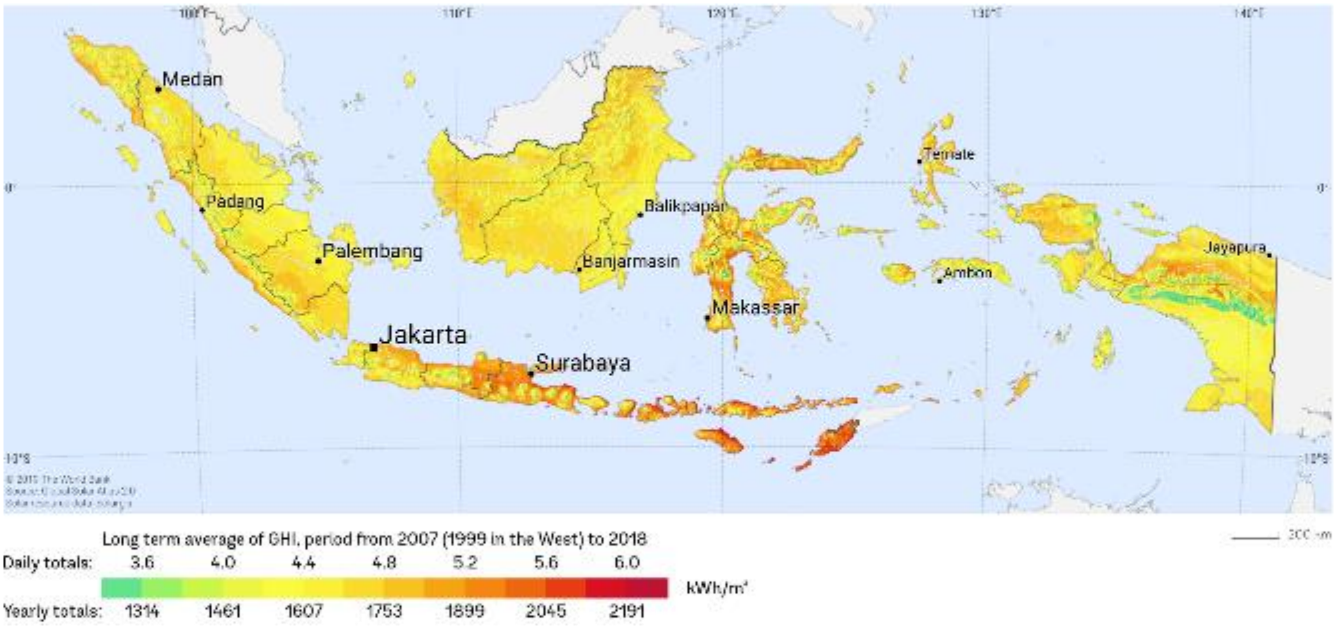
Floating solar PV refers to a solar power production installation mounted on a structure that floats on a body of water, typically an artificial basin, primarily constructed as a water management facility or a lake. Floating PV normally feeds the power grid. The main advantage of floating PV plants is that they do not take up any land, except the limited surfaces necessary for electric cabinet and grid connections. The plants provide a good way to avoid land disputes which frequently happen in Indonesia when it comes to power plant projects.

The yearly yield of floating PV units can be up to 12% higher than of ground-mounted PV panels, thanks to a higher irradiance (albedo effect) and a lower and constant temperature not only on PV cells but also on conductors (ref 35). Other reported benefits include the reduction of water evaporation and eutrophication, which limits the growth of biomass (algae) in artificial and natural basins. Floating PV can ideally be combined with hydropower plants to create a virtual hybrid plant that satisfies different load conditions (ref. 14). Additionally, this combination of floating PV with hydropower can utilize the existing infrastructure thereby reducing the connection and transmission costs.
The current regulation in Indonesia allows for the installation of floating PV on lakes and dams covering 20% of the total water body area, with opportunities to cover larger areas if specific permits are obtained (Ministry of Public Works and Housing regulation no. 7/2023).

Input

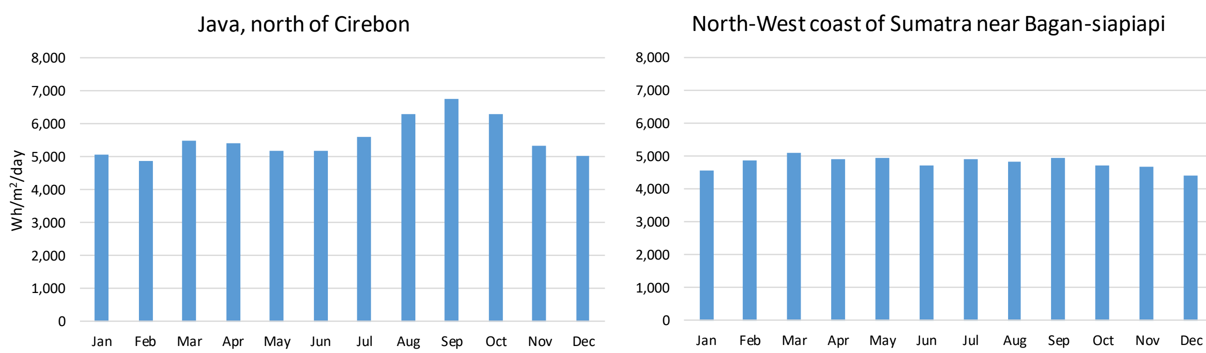
Global Horizontal Irradiation, GHI (direct and diffuse). The GHI hitting the modules depends on the solar resource potential at the location, including shade and the orientation of the module (both tilting from the horizontal plane and deviation from facing south).

The average annual solar energy received on a horizontal surface (Global Horizontal Irradiance, GHI) in Indonesia varies between 1300 kWh and 2200 kWh/m^2, with two-thirds of the land featuring yearly average GHI values between 1600-1800 kWh/m^2. In general, Java, Sulawesi, Bali and East and West Nusa Tenggara demonstrate the best solar locations whereas solar conditions are less good on Kalimantan, Sumatra and Papua.



Global Horizontal Irradiation in Indonesia. Source: Global Solar Atlas (Ref. 15)

Due to Indonesia's geographical location very close to the Equator, the solar irradiation is very constant over the year. The graphs below show the average daily irradiation month by month at a location on Northern Java and the North-West coast of Sumatra.



Monthly variation of the average daily irradiation on horizon plane (Wh/m2/day) at two locations: Java, North Coast near Cirebon and North-West coast of Sumatra near Bagansiapiapi. The GHI of the Java site is 2025 kWh per m2 per annum and for the Sumatra location 1755 kWh per m2 per annum. Source: PVGIS European Communities 2001-2012.

In general, solar panels should be tilted to capture the irradiation *normally*, that is with sunbeams angled 90° at the surface or, in other terms, with a 0° incidence angle. The irradiation to the module can be increased even further by mounting it on a sun-tracking device, this may increase the generation by approximately 22% (based on calculation for the abovementioned Sumatra location with PVGIS).

Output

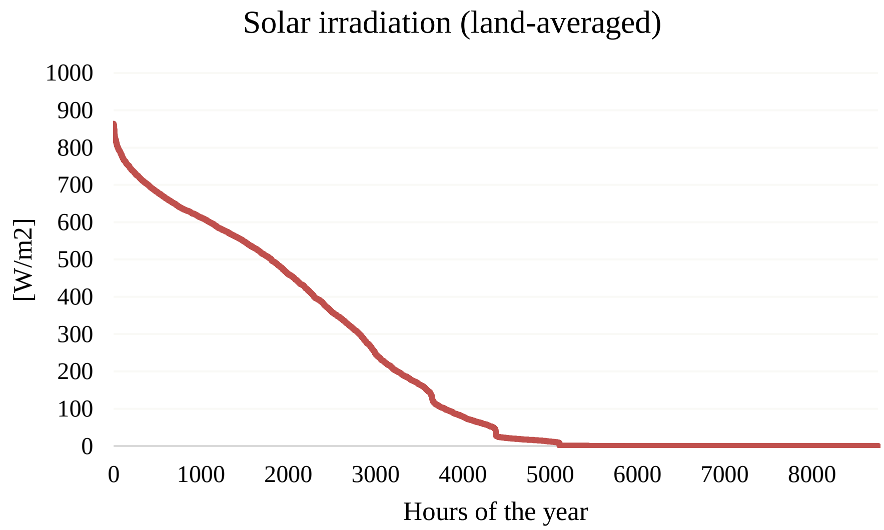
All PV modules generate direct current (DC) electricity as an output, which then needs to be converted to alternating current (AC) by use of an inverter; some modules come with an integrated inverter, so-called AC modules, which exhibit certain technical advantages such as the use of standard AC cables, switchgear and a more robust PV module.

Electricity production depends on:

- The amount of solar irradiation received in the plane of the module (see above).
- Installed module generation capacity.
- Losses related to the installation site (soiling and shade).
- Losses related to the conversion from sunlight to electricity (see below).
- Losses related to conversion from DC to AC electricity in the inverter.
- Grid connection and transformer losses.
- Cable length and cross section, and overall quality of components.

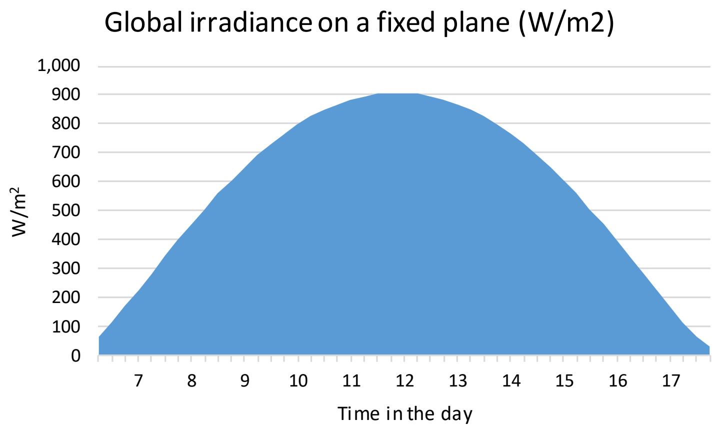
Power generation capacity
The energy generating capacity (power) of a solar module is not a fixed value, as it depends on the intensity of the irradiation that the module receives as well as the module temperature. For practical reasons, the module power capacity is therefore referenced to a set of laboratory Standard Test Conditions (STC) which corresponds to an irradiation of 1000 W/m^2 with an AM1.5 spectral distribution perpendicular to the module surface and a cell temperature of 25°C. The capacity at STC is referred to as the peak capacity P_p [kWp].

Normal operating conditions will often differ from Standard Test Conditions and the average capacity of the module over the year will therefore differ from the peak capacity. The capacity of the solar module is reduced compared to the P_p value when the actual temperature is higher than 25°C; when the irradiation received is collected at an angle different from normal direct irradiation and when the irradiation is lower than 1000 W/m^2. In practice, irradiation levels of 1000 W/m^2 are rarely reached even at the best sites. The plot below shows the land-averaged solar irradiation in Indonesia over a year. Peak values reach 850 W/m^2, while the irradiation is null for nearly 3500 hours.



Land-weighted solar irradiation in Indonesia (duration curve). Source: renewables.ninja

In addition, the graph below shows the global irradiance on a fixed plane (W/m^2) during the day in the Java location; for an average daily profile for September - the month with the best solar conditions.



Global irradiance on a fixed plane (W/m²) during the course of the day in the Java, North Coast near Cirebon; average daily profile for September, the month with the best solar conditions. Source: PVGIS © European Communities 2001-2012.

Besides, some of the electricity generated from the solar panels is lost in the rest of the system e.g. in the DC-to-AC inverter(s), cables, combiner boxes and for larger PV power plants also in the transformer.
The energy production E_{PV} [kWh] from a PV installation can be calculated as follows:

$$E\_PV = A \cdot GHI \cdot \eta\_pre \cdot \eta\_nom \cdot \eta\_rel \cdot \eta\_sys$$

where:

A [m²] is the modules area
GHI [kWh/m²] is the Global Horizontal Irradiation at the location
η_{pre} [%] represents pre-conversion losses (for shading, dirt etc.)
η_{nom} [%]is the module nominal efficiency as specified by the manufacturer, in standard operating conditions
η_{rel} [%] is the module relative efficiency, corrected for the ambient temperature
η_{sys} [%] is the system efficiency, i.e. all losses incurred in cables, electronic components and plant layout.

Maintenance is required to reduce soiling, especially in arid areas, or else η_{pre} can decrease consistently and lower the plant's yield. Temperature is a critical factor in PV systems, as its increase causes a drop in the modules' efficiency. Finally, an optimized plant layout can reduce system losses by minimizing wiring and avoiding mutual shading among modules.

Annual output and capacity factors
Depending on the level of irradiance and the conditions of the installations in terms of losses, degradation, etc, it is possible to calculate the annual output of the PV plant. Often this is expressed in terms of kWh/kW (or full load hours) or in terms of capacity factor, which can be calculated as follows:

$$Capacity\ Factor = \frac{Full\ load\ hour}{8760}$$

The annual output (full load hour) thereby can alternatively be calculated as follows:

$$E = GHI * tf * PR$$

where:

GHI [kWh/m²/year] is the annual Global horizontal irradiation,
tf is the transposition factor for fixed tilt system, considered as 1.01for Indonesia,

PR is the performance ratio considered to be 0.86 in 2023 increasing to 0,97 in 2050.

The annual expectations for output (FLH) and capacity factor for each Indonesian province, can be calculated based on the GHI data from the Global Solar Atlas *(Ref. 15)*:

As can be seen, the variation of the median GHI across provinces is in the range of 1560 to 1770 [kWh/m^2/year].

Province	GHI [kWh/m2/year]		
	P10	Median	P90
Aceh	1,474	1,659	1,844
Bali	1,469	1,739	2,009
Bangka Belitung	1,594	1,663	1,731
Banten	1,390	1,591	1,793
Bengkulu	1,421	1,630	1,839
Grontalo	1,513	1,752	1,991
Jakarta Raya	1,655	1,736	1,816
Jambi	1,442	1,560	1679
Jawa Barat	1,415	1,643	1,870
Jawa Tengah	1,380	1,643	1,905
Jawa Timur	1,434	1,737	2,041
Klimantan Barat	1,479	1,613	1,748
Kalimantan Selatan	1,422	1,579	1,735
Kalimantan Tengah	1,477	1,604	1,731
Kalimantan Timur	1,483	1,635	1,787
Kepulauan Riau	1,563	1,668	1,773
Lampung	1,572	1,684	1,797
Maluku	1,382	1,681	1,980
Maluku Utara	1,459	1,672	1,885
Nusa Tenggara Barat	1,452	1,770	2,089
Papua	1,229	1,544	1,859
Papua Barat	1,382	1,608	1,834
Riau	1,580	1,653	1,726
Sulawesi Barat	1,364	1,652	1,939
Sulawesi Selatan	1,367	1,664	1,962
Sulawesi Tengah	1,373	1,652	1,930
Sulawesi Tenggara	1,402	1,650	1,898
Sulawesi Utara	1,471	1,721	1,971
Sumatera Barat	1,418	1,615	1,812
Sumatera Selatan	1,455	1,611	1,768
Sumatera Utara	1,471	1,633	1,795
Yogyakarta	1,570	1,745	1,920

Inverter capacity and sizing factor

The capacity of the inverter, also known as the rated power, defines the upper limit for power that can be delivered from the plant. The plant capacity $P[W_{ac}]$ is defined as the capacity the plant can feed into the grid. The relationship (Pp/P) between the peak capacity Pp $[W_{DC}]$ of the PV panel and the plant capacity $P[W_{ac}]$, which is the capacity of the inverter, is called the sizing factor (DC/AC sizing factor (Wp/W)). A sizing factor higher than 1 lead to energy "clipping" during peak hours, but at the same time reduces the cost for inverters and grid connection. The sizing factor is optimised differently whether the limiting factor of the installation is availability of area, availability of grid capacity, subsidy scheme, grid tariff scheme, connection fee, imposed constraints on the allowed nominal power, daily self-consumption profile, fixed physical orientation or tilt angle of the modules etc. The range for the sizing factor is generally between 1.0 to 1.35.

Wear and degradation

In general, a PV installation is robust and only requires a minimum of component replacement over its lifetime. The inverter typically needs to be replaced every 10-15 years. For the PV module, only limited physical degradation of a c-Si solar cell will occur. It is common to assign a constant yearly degradation rate of 0.25-0.5% per year to the overall production output of the installation. This degradation rate does not represent an actual physical mechanism. It rather reflects general failure rates following ordinary reliability theory with an initial high (compared to later) but rapidly decreasing "infant mortality", followed by a low rate of constant failures and with an increasing failure rate towards the end-of-life of the various products. Failures in the PV system are typically related to soldering, cell cracks or hot spots, yellowing or delamination of the encapsulant foil, junction box failures, loose cables, hailstorms and lightning (ref. 30).

Efficiency and area requirements

The efficiency of a solar module, η_{mod}, expresses the fraction of the power in the received solar irradiation that can be converted to useful electricity. The average efficiency of commercially available PV modules (crystalline silicon type) in 2022 wes between 17-23% with an average of 20.9% (ref. 20).

The module area needed to deliver 1 kWp of peak generation capacity can be calculated as $1/\eta_{mod}$ on a first approximation and equals around 5 m^2 by 2023 standard PV modules. For modules on tilted roofs, 1 m2 of roof area is needed per m2 of module area. Modules on flat roofs and modules on the ground will typically need more roof and land area than the area of the modules itself, to avoid too much shadowing from the other modules (ref. 31).

Ground-mounted modules may be located very close to each other in Indonesia, since shadow impacts are not an issue. The ground-mounted 1 MW PV plant at Cirata occupies 8.65 m^2 per kWp (1040 kWp using 0.9 hectares area). The newly built Likupang Solar PV at North Sulawesi has a capacity of 21 MWp and land coverage of 29 hectares which is equal to 13.8 m^2 per kWp. Floating PV has different area requirements. The 145 MWp floating Solar PV Cirata has an area coverage of 2.25 km^2. Bali Barat (25 MWp) and Bali Timur (25 MWp) Solar PV would take 12 m^2 per kWp. Further analysis performed for specific sites in Indonesia and Singapore (based on the methodology described in ref. 31) indicates an average area requirement of around 9 m^2 per kWp. This requirement can be expected to decrease as solar PV module efficiency increases in the future.

Typical capacities

Typical capacities for PV systems are available from Watt to GW sizes. But in this context, the focus is PV systems from a few kW for household systems to several hundred MW for utility-scale systems. PV systems are inherently modular with a typical module unit size of 200-500 Wp.

Rooftop PV systems on Indonesia's residential buildings typically have a capacity of about 1 to 10 kW, while commercial or industrial PV systems installed on industries, offices or public buildings typically range from 50 to 500 kW in size. Utility-scale PV plants will normally be ground-mounted and typically range in size from 1 MW to more than 100 MW. They are often operated by independent power producers that by use of transformers deliver electricity to the medium voltage grid.

Ramping configurations and other power system services

The production from a PV system reflects the yearly and daily variation in solar irradiation. Modern PV inverters may be remotely controlled by grid-operators and can deliver grid-stabilisation in the form of reactive power, variable voltage and power fault ride-through functionality. Most of the currently installed PV systems with grid-tied configuration, net metering facilities, and energy storage possibilities supply the full amount of available energy to the consumer/grid. Without appropriate grid regulation in place, high penetration of PV can also lead to unwanted increases in voltage along with other issues.

Advantages/disadvantages

Advantages:

- PV does not use any fuel or other consumables.
- PV is noiseless (except for fan noise from inverters).
- PV does not generate any emissions during operation.
- Electricity is produced in the daytime when demand is usually high.
- With Indonesian solar conditions, the monthly electricity generation from solar PV is quite stable, i.e. no significant seasonal variations.
- PV offers grid-stabilization features.
- PV modules have a long lifetime of more than 30 years and PV modules can be recycled.
- PV systems are modular and easy to install.
- Operation & Maintenance (O&M) of PV plants is simple and limited as there are no moving parts and no wear and tear, except tracers. Inverters must only be replaced once or twice during the operational life of the installation.
- Large PV power plants can be installed on land that otherwise is of no commercial use e.g. on landfills, areas of restricted access or chemically polluted areas, on hydro dams (reducing the water evaporation from the dams).
- PV systems integrated into buildings require no incremental ground space, and the electrical interconnection is readably available at no or small additional cost.

Disadvantages:

- PV systems have relatively high initial costs.
- The space requirement for solar panels per MW is significantly higher than for thermal power plants.
- The output of the PV installation can only be adjusted negatively (reduced feed-in) according to demand as production follows the daily and yearly variations in solar irradiation.
- Materials abundance (In, Ga, Te) is of concern for large-scale deployment of some thin-film technologies (CIGS, CdTe).
- Some thin-film technologies do contain small amounts of cadmium and arsenic.
- The best perovskite absorbers contain soluble organic lead compounds, which are toxic and environmentally hazardous at a level that calls for extraordinary precautions.

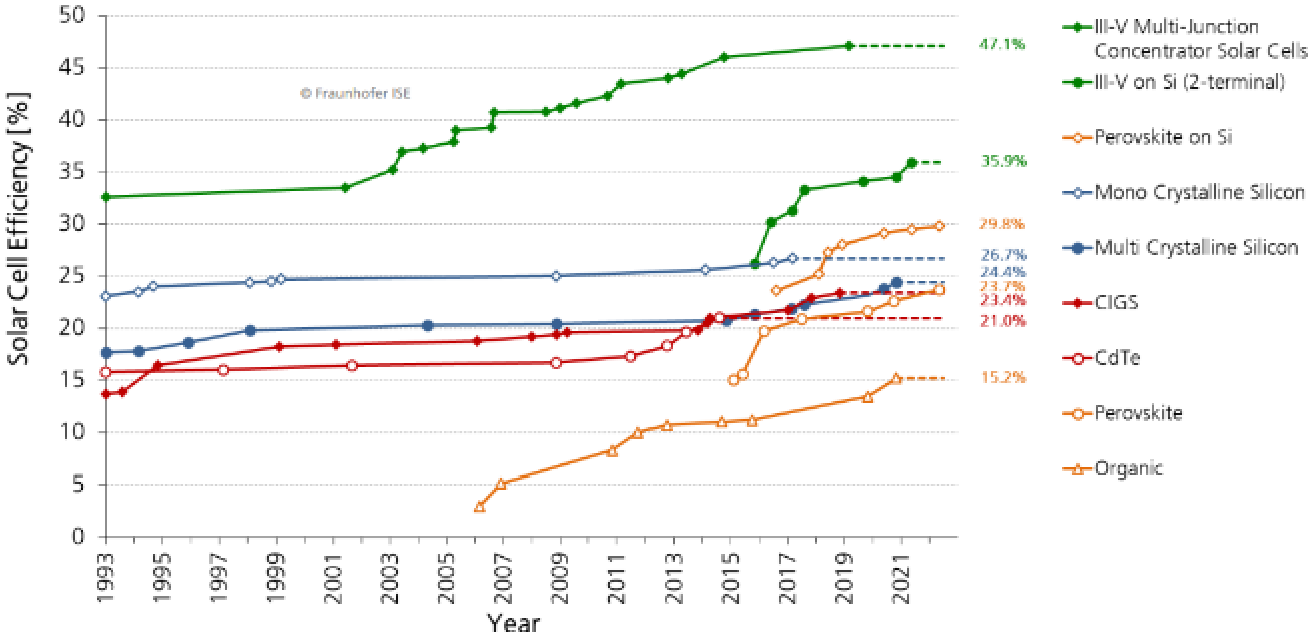
Environment
The environmental impacts from manufacturing, installing and operating PV systems are limited. Thin film modules may contain small amounts of cadmium and arsenic. In the EU all PV modules as well as inverters are covered by the European Union WEEE directive, whereby appropriate treatment of the products by end-of-life is promoted. The energy payback time of a typical crystalline silicon PV system in Southern Europe is 1.25 years. Regardless, Indonesia is projected to potentially generate over 1.5 million tonnes of PV waste in 2060, considering 100 GW of solar PV installed by 2030 to achieve Zero Emissions Target by 2060. (ref 18).

Employment
Most parts from solar PV can be produced in Indonesia. As of the year 2022, there are 21 PV manufacturers in Indonesia with a total manufacturing capacity of around 1.6 GW of modules. One manufacturer is PT. LEN Industri with a production capacity of 71 MWp and employment of about 520 people. Another is Hanover Solar with an annual production of 200 MW solar PV modules in Batam island with around 300 full-time employees.
There are currently plans for a very significant increase in solar PV manufacturing capacity in Indonesia which holds a large potential for job creation. This currently includes expansion to also include cell manufacturing and reaching towards 10 GWp of annual module capacity output (ref. 32). It is estimated that at larger scales around 1300 direct manufacturing jobs can be created throughout the supply-chain for a 1 GWp production, with cell and module manufacturing accounting for more than 75% of the total jobs (ref. 33).

The operating Kupang 5 MW project hires 10 full-time employees for the operation. Likupang Solar PV at North Sulawesi employs about 900 local workforces during construction.
The institute for Essential Services Reform (IESR) of Indonesia has proposed a program called "1 enstitute for Essential Services Reform (IESR) of Indonesia has proposed a program called "1 hnstitute for Essential Services Reform (IESR) of Indonesia has proposed a program called "1 Wp Solar PV for Households". It is expected that the program will create about 78,000 jobs, direct and indirect.

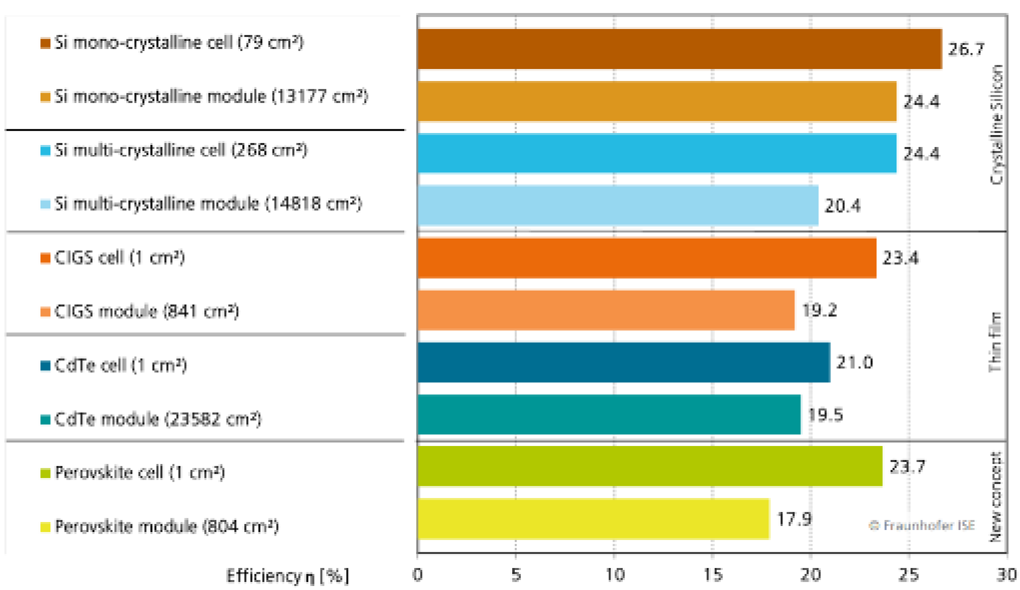
Research and development
PV technology is a commercial technology, but subject to sizeable performance improvements and cost decreases (category 3). A trend in research and development (R&D) activities reflects a change of focus from manufacturing and scale-up issues and cost reduction topics to implementation of high-efficiency solutions and documentation of lifetime/durability issues. R&D is primarily conducted in countries where the manufacturing also takes place, such as Germany, China, USA, Taiwan and Japan.

The figure below highlights the historical development of the laboratory solar cell efficiencies within the crystalline silicon cells, multijunction cells, thin film technologies, and emerging photovoltaics. The world record for each technology is mentioned by the efficiency % along the right edge. The world record of 26.7% efficiency for mono-crystalline Silicon (sc-Si) was achieved in 2021. (ref. 20)



Development of laboratory solar cell efficiency (ref. 20)

Apart from the developments in cell efficiency, the R&D in module efficiency solutions have also improved the Cell-to-Module ratio (CTM) by reducing losses and utilizing the possible gains while integrating the solar cells in the modules such that the module efficiency. The module efficiency of sc-Si has now reached 24.4% (ref. 20) Similar, progress is achieved with regard to other cell technologies, as presented by the efficiency comparison figure below:



Efficiency comparison of best lab cells vs. best lab modules (ref. 20)

Investment cost estimation

The cost of solar PV projects has decreased significantly both in Indonesia and internationally with an average reduction of around 20-25% each time the accumulated installed capacity has doubled (the learning rate).

The historical system cost reductions are a result of various factors, but the solar PV modules have been responsible for the majority of the reductions since 2010.

Assumed average costs for projects in 2022 were around 0.260 USD/Wp in China (ref. 28) and in mid-2023 average price globally of polysilicon solar modules was 0.176 USD/Wp, with prices as low as 0.160 USD/Wp (ref 19). By the end of 2023, imported modules from China to Indonesia have been as low as 0.130 USD/Wp in some cases, down from around 0.380 USD/Wp in 2017 (ref. 34). Based on stakeholder engagement it is estimated that domestically manufactured modules have around 50% higher costs than imported ones, although there is very large variation in costs due to volatile raw material prices and other parameters.

The combined cost for PV modules and inverters in Indonesia is about 0.4 USD/Wp, compared to 0.3 USD/Wp in China and 0.5 USD/Wp in Japan for recently established projects (ref. 28).

The historical cost reductions have also been seen in the announced solar PV projects. The Cirata Floating PV project (started commercial operation in 2023) and two projects in Bali (PPA signed in 2022) have resulted in PPA prices of 5.8-5.9 c/kWh, which is a reduction of nearly 80% compared to smaller projects signed in 2015-2016. Several projects were awarded at even lower bid prices of around 3.7 c/kWh at the end of 2020 (ref. 13). However, the awarded bids have not resulted in final PPAs or construction of the projects yet.

The forecasted price is based on the expectation that the technology development will continue to bring down costs in line with the historical trends. Cost projections from various references have been considered, with a central estimate of a 30% reduction by 2030 and a further 30% reduction between 2030-2050.The solar PV industry has notched up the competitiveness of manufacturing processes in recent years, driven by considerable R&D spending on cell materials and module design. Future costs for solar PV in Indonesia will depend on local content rules, import duties and the rise of a competitive manufacturing industry in the country; cost reductions will also be achieved through a more solid experience in the project development and installation stages. The cost gap between local manufacturers and imported modules is expected to narrow with time, leading to convergence with international prices in the long term. This is supported by the fact that there are plans to develop significant domestic manufacturing capacity, incl. from tier-1 enterprises, within the coming years (ref. 32).

The investment costs of other types of PV plants (rooftop and floating) are higher than those of ground-mounted PV due to the economy of scale for the smaller plants and for utility-scale floating PV due to the maturity of the system. Floating PV and household rooftop PV are considered to cost roughly 25% more than a utility-scale ground-mounted plant in 2023. Utility-scale floating PV it is expected that the cost will diverge fast towards the cost for utility-scale ground-mounted plants.

The table below summarizes investment cost figures from relevant sources, along with the recommended values (ground-mounted PV). Note that it is generally difficult to compare between sources as there are differences in the type of information shared, specifically if it’s based on MW or MWp capacity and the amount of soft costs included. The Indonesian catalogue assumes a sizing factor (MWp/MW) of 1.2 which influences results compared to other references without any such information. More details on the cost breakdowns are included in the quantative data tables.

Investment cost estimations, overview of examples of costs

Investment costs [$MUSD_{2022}$/MW]		2020	2023	2030	2050
Catalogues	**New Catalogue (2023)**	-	**0.96**	**0.67**	**0.48**
	Existing Catalogue (2020)	0.90		0.64	0.47
Indonesia data	MEMR FGDs 2023[1]	0.75-3.07	0.83-1.09		
	Feed-in Tariff, calculation[3]	0.71			
	IRENA[2] (Indonesian data for 2022)		0.96		
International data	Technology catalogue Vietnam (2023)	0.93	-	0.65	0.48
	IRENA[2,5] (Global average)	0.98	0.87	0.39-0.97	0.19-0.56
	IEA WEO 2023 (average of India and China)		0.68	0.40	0.27
	IEA WEO 2023 (average of US and EU)		1.05	0.63	0.44
	Lazard [4]	-	0.70-1.40		
Projection	Development curve – cost trend [%]	-	100%	70%	50%

[1]MEMR Focus Group Discussions with various stakeholders for the purposes of updating the Technology Catalogue in 2023
[2]IRENA (2023), Renewable power generation costs in 2022 for 2020-2023 values. Note that data is for full system costs incl. soft costs and given per MWp.
[3]FIT levels proposed by ESDM in draft PERPRES Harga Listrik EBT. Back calculation of CAPEX based on 12% WACC.
[4]Lazard. (2023). Lazard's Levelized Cost of Energy Analysis—Version 16.0.
[5]Future values for 2030-2050 based on IRENA (2019), Future of Solar PV. Note that data is for full system costs incl. soft costs and given per MWp.

Examples of current projects

Floating Solar PV:

The Cirata Floating Photovoltaic Power Plant (ref 27+29)

Pembangkitan Jawa Bali Masdar Solar Energy (PMSE) Cirata Floating Photovoltaic Power Plant project began commercial operation in November 2023. It is built on a 225-hectare plot of the 6200-hectare large Cirata reservoir in the West Java Province. It will provide enough electricity to power 50,000 homes and contribute to the creation of up to 800 jobs during the installation. Masdar, one of the renewable energy companies, and PT PJBI, a subsidiary of Indonesia's state-owned electricity company PT PLN, announced in August 2021 that financial close has been achieved on the Cirata Floating Photovoltaic Power Plant project and construction work has begun. Financing for the project was arranged through Sumitomo Mitsui Banking Corporation, Societe Generale, and Standard Chartered Bank. The 145-megawatt (AC) plant is being developed by PT PJBI throughout the development of the project, Masdar has conducted a series of social initiatives, raising awareness of sustainability issues, and strengthening local community engagement. After signing the PPA with PLN, the company agreed to sell the electricity produced at 5.8 US cents/kWh.

Following the success, Indonesia set up another plan to install a total of 857 MW floating solar PV on the following dams/lakes:

- Wonogiri dam at Wonogiri, Central Jawa
- Sutami dam at Karangkates, East Jawa
- Jatiluhur dam at Purwakarta, West Jawa
- Mrica dam at Banjarnegara, Central Jawa
- Saguling dam at Cianjur, West Jawa
- Wonorejo dam at Tulung Agung, East Jawa
- Singkarak Lake at Solok, West Sumatera

Cirata floating solar project 2 (Ref 8)
Furthermore, in March 2023 Sungrow FPV, a Chinese-based provider of floating solar solutions, secured a contract for the supply of a 192MW floating systems in Indonesia. The construction of the Cirata floating solar project will begin in the first quarter of 2023. Sungrow FPV informed that it is a 'landmark project' as at the time of the contract, it was the largest floating solar project in Indonesia with the deepest water depth, largest water level fluctuation, and highest underwater elevation difference (94 meters water depth, 18 meters water level fluctuation, and 50 meters underwater elevation difference). The biggest challenge is the stress concentration issues caused by thousands of anchors that are located at various elevations and complex topography.

Ground-mounted Solar PV:
Bali Barat and Timur Solar PV. (Ref. 9)
SP-Medco West Bali Solar PV Park is a 25MW solar PV power project, the project is currently at the permitting stage (June 2023). It will be developed in a single phase. The project construction is likely to begin in 2023 and is expected to enter into commercial operation in 2025. This is a part of the plan of Medco Power Indonesia and Solar Philippines Consortium to develop ground-mounted PV projects. Namely, Bali Barat and Bali Timur Solar PV project with a total installed capacity of respectively 50 MW and 25 MW in West and East Bali. As per the PPA, PLN will buy the electricity for the West Bali project at 5.9 US cents/kWh and the East Bali project at 5.6 US cents/kWh.

Another ground-mounted PV in operation since 2019 is Likupang Solar PV. With aninstalled capacity of 21 MW. It is located at Likupang in North Sulawesi. The building time from FID was one and a half years to finish the project. Vena Energy, a Singapore based company, owns this project. According to the company, they invested about 29.2 million USD to build the Likupang solar PV and employed 600 residents of nearby communities while constructing the project. It covers about 29 hectares of land and can produce 33.4 GWh of energy per year.

Likupang Solar PV in North Sualwesi. (Ref. 10)

To avoid or minimize land disputes, Indonesia has a plan to develop Solar PV projects on abandoned coal and tin mines in Bangka Belitung and Kalimantan islands. The total abandoned mining areas that will be used to deploy solar PV in those islands are 2700 hectares. The power output that would be generated is about 2,300 MWp and distributed as follows:

- Bangka Belitung: 1,250 MW
- Kutai Barat, East Kalimantan: 1000 MW
- Kutai Kartanegara, East Kalimantan: 53 MW

Commercial Rooftop Solar PV:

PT Coca Cola Amatil Indonesia Rooftop PV. (Ref. 11)

The interest in rooftop PV (on-grid) is growing in Indonesia. Interest in the installation has increased among households, businesses, and commercial customers, especially after the revision of MEMR Minister Ordinance No. 49/2018.

PT Coca-Cola of Indonesia has decided to build a 7.13 MW rooftop PV at their factory in Bekasi, West Jawa. The rooftop solar panels are installed on the factory roof covering an area of 72,000 m². Coca-Cola issued an investment fund of 87 billion rupiahs.

PT Coca Cola Amatil Rooftop PV at Bekasi, West Jawa (Ref. 11)

Another example is PT Aqua Danone rooftop PV which is located at Klaten, Central Jawa. It was just commercially in operation on 6 October 2020. It has a capacity of 2.9 MWp. This rooftop PV is expected to generate 4 GWh of electricity per year. Currently, it is the largest rooftop PV in Indonesia. Actually, for Aqua Danone this is the second rooftop PV that has been installed on their factory roof. The first one was at Cikarang, West Jawa installed in 2017 with a capacity of 770 kWp which can generate 1 GWh of electricity per year.

PT Aqua Danone Rooftop PV at Klaten, Central Jawa (Ref. 12)

PLTS Rooftop Cikarang Listrindo (ref 26)
In April 2022 it is announced that PT. Cikarang Listrindo Tbk (POWR) has added a rooftop solar power plant (PLTS) on the customer's rooftop by 10.9 MWp.

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The description in this chapter is to a great extend from the Danish Technology Catalogue *"Technology Data on Energy Plants - Generation of Electricity and District Heating, Energy Storage and Energy Carrier Generation and Conversion".* The following are sources used:

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Datasheets

The following pages contain the data sheets of the technology. All costs are stated in U.S. dollars (USD), price year 2022. The *uncertainty* is related to the specific parameters and cannot be read vertically – meaning a product with e.g., lower efficiency does not have a lower price.

Technology

Technology	PV ground-mounted, utility-scale, grid connected								
	2023	2030	2050	Uncertainty (2023)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity a typical power plant (MWe)	50	80	100					A	1
Electricity efficiency, net (%), name plate	-	-	-					B	
Electricity efficiency, net (%), annual average	-	-	-					B	
Forced outage (%)	-	-	-						
Planned outage (weeks per year)	-	-	-						
Technical lifetime (years)	27	30	35	25	30	28	42		1
Construction time (years)	0.5	0.5	0.5	0.5	1.5	0.3	1.0		1
Space requirement (1000 m^2/MWp)	9.1	8.3	7.5	6.0	13.0	5.0	12.0	U,V	7,8
Additional data for non thermal plants									
Capacity factor (%), theoretical	20.5	21.1	21.7	17.5	23.6	18.4	24.9	L,M	1,2,3
Capacity factor (%), incl. outages	20.4	21.0	21.6	17.4	23.5	18.3	24.8	L,M,X	1,2,3
Ramping configurations									
Ramping (% per minute)	-	-	-	-	-	-	-	C	
Minimum load (% of full load)	-	-	-	-	-	-	-	C	
Warm start-up time (hours)	-	-	-	-	-	-	-	C	
Cold start-up time (hours)	-	-	-	-	-	-	-	C	
Environment									
PM 2.5 (gram per Nm^3)	0	0	0						
SO_2 (degree of desulphuring, %)	0	0	0						
NO_X (g per GJ fuel)	0	0	0						
CH_4 (g per GJ fuel)	0	0	0						
N_2O (g per GJ fuel)	0	0	0						
Financial data									
Nominal investment (M$/MWe)	0.96	0.67	0.48	0.83	1.50	0.29	0.60	E,P,R,S	1,4,5,8,9
- of which equipment	85%	80%	76%						1,4
- of which installation	15%	20%	24%					W	1,4
Fixed O&M ($/MWe/year)	7,500	6,800	6,100	3,800	11,300	3,100	9,200	Q	1,4
Variable O&M ($/MWh)	0	0	0						
Start-up costs ($/MWe/start-up)	0	0	0						
Technology specific data									
Global horizontal irradiance (kWh/m2/y)	1,700	1,700	1,700	1,300	2,200	1,300	2,200	F	1,2,3
DC/AC sizing factor (Wp/W)	1.20	1.20	1.20					G	1,5
Transposition Factor for fixed tilt system	1.01	1.01	1.01					H	3
Performance ratio [-]	0.86	0.90	0.92					I	1,5
PV module conversion efficiency (%)	0.205	0.23	0.26						1,4,5
Inverter lifetime (years)	12.5	15.0	15.0						5
Output									
Full load hours (kWh/kW)	1,800	1,850	1,900	1,350	2,300	1,450	2,450	J, L,M	
Peak power full load hours (kWh/kWp)	1,500	1,550	1,600	1,600	2,750	1,750	2,950	K, L,M	
Financial data									
PV module & inverter cost ($/Wp)	0.41	0.27	0.18	0.35	0.64	0.11	0.23		1,4
Balance Of Plant cost ($/Wp)	0.27	0.18	0.12	0.23	0.43	0.07	0.15		1,4
Installation and other cost ($/Wp)	0.12	0.11	0.10	0.10	0.19	0.06	0.12	W	1,4
Specific investment, total system ($/Wp)	0.80	0.56	0.40	0.69	1.25	0.24	0.50	E	1,4,5,8,9
Specific investment, total system (M$/MW)	0.96	0.67	0.48	0.83	1.50	0.29	0.60	P	1,4,5,8,9

References:

1 MEMR Focus Group Discussions with various stakeholders for the purposes of updating the Technology Catalogue in 2023

2 Data analysed from www.renewables.ninja for multiple locations in Indonesia.

3 PVGIS © Europeen Communitees 2001-2012.

4 IRENA, Renewable Power Generation Costs in 2022, 2023

5 The Danish Energy Agency, Technology data for generation of electricity and district heating, 2023.

6 Space requirement mapped for local utility-scale PV by EA Energy Analysis in 2023, based on emthodology of ref. 7

7 M. Bolinger and G. Bolinger, Land Requirements for Utility-Scale PV: An Empirical Update on Power and Energy Density, 2022

8 World Energy Outlook 2022, IEA, 2023

9 IRENA, Future of Solar PV - Deployment, investment,technology, grid integration and socio-economic aspects, 2019

Notes:

A Listed as MWe. The MWp will depend on the DC/AC siizing factor

B See "PV module conversion efficiency (%)". The improvement in technology development is also captured in capacity factor, investment costs and space requirement.

C The generation from a PV system reflects the yearly and daily variation in solar irradiation. It is possible to curtail solar, and this can be done rapidly.

E Investment cost include the engineering, procurement and construction (EPC) cost. See description under Methodology.

F The global horizontal irradiation is a measure of the energy resource potential available and depends on the exact geographical location. 1700 kWh/m2/year corresponds to a resource slightly above the median value in Java. The range of GHI across the country ranges from 1300 kWh/m2 to 2200 kWh/m2.

G The DC/AC equals module peak capacity Wp divided by plant capacity We (output of the inverter). The sizing factor is chosen according to the desired utilisation/loading of the inverter which can also reflect a desire to maximise the energy production from a given (restricted) AC-capacity.

H The transposition factor describes the increase in the sunlight energy that can be obtained by tilting the module with respect to horizontal and reduction in received energy when the orientation deviates from South. The TF factor is set to the same value for all years and sizes of the system, as it is not the technical factors of the system, which determine the TF. In Indonesia the TF factor for fixed systems is very low, adding only 0-1 % to the production.

I The performance ratio is an efficiency measure which takes the combined losses from incident angle modifer, inverter loss, PV systems losses and non-STC corrections and AC grid losses into account. The Incident Angle Modifier (IAM) loss represents the total yearly solar energy that is reflected from the glass when the angle of incidence is different from the perpendicular (the reflections at a normal incidence is already included in the STC efficiency). PV systems losses and non- STC corrections are calculated by simulating a model-year where corrections are made hour-by-hour due to the fact that the actual operation does not take place under STC conditions. Additionally, electrical losses in cables are included. The inverter loss includes the Maximum Power Point Tracking (MPPT) efficiency and is averaged over typical load levels. An addition to the ratio is the potential added benefit of having bifacial modules which raise the generation by 5%.

J The full load hours is defined as the peak full load hours*DC/AC sizing factor

K The number of full load hours is calculated based on the other values in the table. The formula is: Peak full load hours = Global horizontal irradiance * transposition factor * performance ratio.

L Capacity factor = Full load hours / 8760.

M The capacity factor or full load hours depend greatly on the global horizontal irradiance at the specific plant site. For sites significantly different from the 1700 kWh/m2/year solar irradiation mentioned here, the caacity factors should be adjusted accordingly.

P The "specific investment, total system per rated capacity W(AC)" is calculated as "specific investment, total system per Wp(DC)" multiplied by the sizing factor.

Q The cost of O&M includes insurance and regular replacement of inverters, technical operation, preventive maintenance, commercial operation, corrective maintenance, insurance, greenkeeping and security. O&M costs are assumed to decrease slower than for equipments. Reported values have a wide range so a +/- 50% interval is suggested for the uncertainty intervals.

R Invstment cost projections and unertainty ranges are based on a continued reduction estimated from a number of sources incl. ref. 1, 5, 8, 9.

S For 2023, uncertainty ranges are based on cost spans of various sources, incl. Focus Group Discussions with various stakeholders

T PV module conversion efficiency (%) is the ration of the energy from the sun that hits the solar panel that is coverted into DC eletricity in the module.

U Estimations of space requirements are based on the mapping of the average polygonal area occupied by PV arrays and electrical equipments like inverter pad of existing utility scale PV plants in Indonesia and Singapore. The methode is decribed in [8].

V The space requirement is reduced because of the improved efficiency of the modules, assuming that total area decrease by only 80 % of the decreased demand for modul area.

W The cost of labour and the installation performance is not expected to improve in the same extent as the costs for the equipment. Therefore, the share of installation cost would increase over the years.

X Yearlly outage time is assumed to be 0,5 % equal to approxemately 2 hours.

Technology

Technology	PV household scale, rooftop, grid connected								
	2023	2030	2050	Uncertainty (2023)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for total power plant (kWe(AC))	5	5	5					A	1
Electricity efficiency, net (%), name plate	-	-	-					B	
Electricity efficiency, net (%), annual average	-	-	-					B	
Forced outage (%)	-	-	-						
Planned outage (weeks per year)	-	-	-						
Technical lifetime (years)	27	30	35	25	30	28	42		1
Construction time (years)	0.1	0.1	0.1	0.1	0.5	0.1	0.5		1
Space requirement (m^2/kWe(AC))	5.1	4.6	4.1	4.4	6.0	4.0	5.5	V	1
Additional data for non thermal plants									
Capacity factor (%), theoretical	20.5	21.1	21.7	17.5	23.6	18.4	24.9	L,M	1,2,3
Capacity factor (%), incl. outages	20.4	21.0	21.6	18.4	22.5	19.4	23.7	L,M,X	1,2,3
Ramping configurations									
Ramping (% per minute)	-	-	-	-	-	-	-	C	
Minimum load (% of full load)	-	-	-	-	-	-	-	C	
Warm start-up time (hours)	-	-	-	-	-	-	-	C	
Cold start-up time (hours)	-	-	-	-	-	-	-	C	
Environment									
PM 2.5 (gram per Nm^3)	0	0	0						
SO_2 (degree of desulphuring, %)	0	0	0						
NO_X (g per GJ fuel)	0	0	0						
CH_4 (g per GJ fuel)	0	0	0						
N_2O (g per GJ fuel)	0	0	0						
Financial data									
Nominal investment (M$/MWe)	1.20	0.84	0.60	1.15	1.92	0.36	0.76	E,R,S	1,4,5,6,8,9
- of which equipment	80%	75%	70%						1,5,6
- of which installation	20%	25%	30%					W	1,5,6
Fixed O&M ($/MWe/year)	4,900	4,400	3,900	2,500	7,400	2,000	5,900	Q	1,5,6
Variable O&M ($/MWh)	0	0	0						
Start-up costs ($/MWe/start-up)	0	0	0						
Technology specific data									
Global horizontal irradiance (kWh/m2/y)	1,700	1,700	1,700	1,300	2,200	1,300	2,200	F	2,3
DC/AC sizing factor (Wp/W)	1.20	1.20	1.20					G	1,4
Transposition Factor for fixed tilt system	1.01	1.01	1.01					H	3
Performance ratio	0.86	0.90	0.92					I	1,4
PV module conversion efficiency (%)	0.205	0.23	0.26					T	1,4,6
Inverter lifetime (years)	12.5	15.0	15.0						4
Output									
Full load hours (kWh/kW)	1,800	1,850	1,900					J, L	
Peak power full load hours (kWh/kWp)	1,500	1,550	1,600					K, L	
Financial data									
PV module & inverter cost ($/Wp)	0.68	0.45	0.30	0.65	1.09	0.18	0.37		1,5,6
Balance Of Plant cost ($/Wp)	0.12	0.08	0.05	0.12	0.19	0.03	0.07		1,5,6
Installation and other cost ($/Wp)	0.20	0.18	0.15	0.19	0.32	0.09	0.19	W	1,5,6
Specific investment, total system ($/Wp)	1.00	0.70	0.50	0.96	1.60	0.30	0.63	E,R,S	1,4,5,6,8,9
Specific investment, total system (million $/MW)	1.20	0.84	0.60	1.15	1.92	0.36	0.76	P	1,4,5,6,8,9

References:

1 MEMR Focus Group Discussions with various stakeholders for the purposes of updating the Technology Catalogue in 2023
2 Data analysed from www.renewables.ninja for multiple locations in Indonesia.
3 PVGIS © Europeen Communitees 2001-2012.
4 The Danish Energy Agency, Technology data for generation of electricity and district heating, 2023.
5 USAID, Panduan Perencanaan dan Pemanfaatan PLTS ATAP DI INDONESIA, 2020
6 IRENA, Renewable Power Generation Costs in 2022, 2023
7 IESR, Indonesia Solar Energy Outlook 2023
8 World Energy Outlook 2022, IEA 2023
9 IRENA, Future of Solar PV - Deployment, investment,technology, grid integration and socio-economic aspects, 2019

Notes:

A Listed as MWe. The MWp will depend on the DC/AC siizing factor

B See "PV module conversion efficiency (%)". The improvement in technology development is also captured in capacity factor, investment costs and space requirement.

C The generation from a PV system reflects the yearly and daily variation in solar irradiation. It is possible to curtail solar, and this can be done rapidly.

E Investment cost include the engineering, procurement and construction (EPC). See description under Methodology.

F The global horizontal irradiation is a measure of the energy resource potential available and depends on the exact geographical location. 1700 kWh/m2 corresponds to a resource slightly above the median value in Java. The range of GHI across the country ranges from 1330 kWh/m2 to 2200 kWh/m2.

G The DC/AC equals module peak capacity Wp divided by plant capacity We(output of the inverter). The sizing factor is chosen according to the desired utilisation/loading of the inverter which can also reflect a desire to maximise the energy production from a given (restricted) AC-capacity.

H The transposition factor describes the increase in the sunlight energy that can be obtained by tilting the module with respect to horizontal and reduction in received energy when the orientation deviates from South. The TF factor is set to the same value for all years and sizes of the system, as it is not the technical factors of the system, which determine the TF. In Indonesia the TF factor for fixed systems is very low, adding only 0-1 % to the production.

I The performance ratio is an efficiency measure which takes the combined losses from incident angle modifer, inverter loss, PV systems losses and non-STC corrections and AC grid losses into account. The Incident Angle Modifier (IAM) loss represents the total yearly solar energy that is reflected from the glass when the angle of incidence is different from the perpendicular (the reflections at a normal incidence is already included in the STC efficiency). PV systems losses and non- STC corrections are calculated by simulating a model-year where corrections are made hour-by-hour due to the fact that the actual operation does not take place under STC conditions. Additionally, electrical losses in cables are included. The inverter loss includes the Maximum Power Point Tracking (MPPT) efficiency and is averaged over typical load levels. An addition to the ratio is the added benefit of having bifacial modules which raise the generation by 5%.

J The full load hours is defined as the peak full load hours*DC/AC sizing factor

K The number of full load hours is calculated based on the other values in the table. The formula is: Peak full load hours = Global horizontal irradiance * transposition factor * performance ratio.

L Capacity factor = Full load hours / 8760.

M The capacity factor or full load hours depend greatly on the global horizontal irradiance at the specific plant site. For sites significantly different from the 1700 kWh/m2/year solar irradiation mentioned here, the caacity factors should be adjusted accordingly.

P The "specific investment, total system per rated capacity W(AC)" is calculated as "specific investment, total system per Wp(DC)" multiplied by the sizing factor.

Q The cost of O&M includes insurance and regular replacement of inverters, technical operation, preventive maintenance, commercial operation, corrective maintenance, insurance, greenkeeping and security. O&M costs are assumed to decrease slower than for equipments. Reported values have a wide range so a +/- 50% interval is suggested for the uncertainty intervals.

R Invstment cost projections and future unertainty ranges are assumed to be similar to the ones for ground-mounted plants and is based on a continued cost redutions estimated from a number of sources, incl. ref. 1, 4, 8, 9.

S For 2023, uncertainty ranges are based on cost spans of various sources.

T PV module conversion efficiency (%) is the ration of the energy from the sun that hits the solar panel that is coverted into DC eletricity in the module.

V The space requirement is reduced because of the improved efficiency of the modules, assuming that total area decrese by only 95 % of the decreased demand for modul area.

W The cost of labour and the installation performance is not expected to improve in the same extent as the costs for the equipment. Therefore, the share of installation cost would increase over the years.

X Yearlly outage time is assumed to be 0,5 % equale approxemately 2 hour.

Technology

Technology	PV Industrial scale, rooftop or ground mounted - grid connected								
	2023	2030	2050	Uncertainty (2023)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for total power plant (kWe)	100	100	100					A	1
Electricity efficiency, net (%), name plate	-	-	-					B	
Electricity efficiency, net (%), annual average	-	-	-					B	
Forced outage (%)	-	-	-						
Planned outage (weeks per year)	-	-	-						
Technical lifetime (years)	27	30	35	25	30	28	42		1
Construction time (years)	0.5	0.5	0.5	0.5	1.5	0.3	1.0		1
Space requirement (1000 m^2/MWe)	5.1	4.6	4.1	4.4	6.0	4.0	5.5	V	1
Additional data for non thermal plants									
Capacity factor (%), theoretical	20.5	21.1	21.7	16.1	19.6	18.1	22.1	L,M	1,2,7
Capacity factor (%), incl. outages	20.4	21.0	21.6	18.4	22.5	19.4	23.7	L,M,X	1,2,7
Ramping configurations									
Ramping (% per minute)	-	-	-	-	-	-	-	C	
Minimum load (% of full load)	-	-	-	-	-	-	-	C	
Warm start-up time (hours)	-	-	-	-	-	-	-	C	
Cold start-up time (hours)	-	-	-	-	-	-	-	C	
Environment									
PM 2.5 (gram per Nm^3)	0	0	0						
SO_2 (degree of desulphuring, %)	0	0	0						
NO_X (g per GJ fuel)	0	0	0						
CH_4 (g per GJ fuel)	0	0	0						
N_2O (g per GJ fuel)	0	0	0						
Financial data									
Nominal investment (M$/MWe)	1.08	0.76	0.54	1.03	1.73	0.32	1.30	E,R,S	1,3,5,6,8,9
- of which equipment	80%	75%	70%					D	1,5,6
- of which installation	20%	25%	30%					D,W	1,5,6
Fixed O&M ($/MWe/year)	4,700	4,200	3,700	2,400	7,100	1,900	5,600	Q	4,5
Variable O&M ($/MWh)	0	0	0						
Start-up costs ($/MWe/start-up)	0	0	0						
Technology specific data									
Global horizontal irradiance (kWh/m2/y)	1,700	1,700	1,700	1,300	2,200	1,300	2,200	F,M	1,2,7
DC/AC sizing factor (Wp/We)	1.20	1.20	1.20					G	1,5
Transposition Factor for fixed tilt system	1.01	1.01	1.01					H	7
Performance ratio	0.86	0.90	0.92					I	1,5
PV module conversion efficiency (%)	0.21	0.23	0.26					T	1,3,5
Inverter lifetime (years)	12.5	15.0	15.0						5
Output									
Full load hours (kWh/kW)	1,800	1,850	1,900					J,L	
Peak power full load hours (kWh/kWp)	1,500	1,550	1,600					K,L	
Financial data									
PV module & inverter cost ($/Wp)	0.61	0.40	0.27	0.58	0.98	0.16	0.64	D	1,5,6
Balance Of Plant cost ($/Wp)	0.11	0.07	0.05	0.10	0.17	0.03	0.11	D	1,5,6
Installation and other cost ($/Wp)	0.18	0.16	0.14	0.17	0.29	0.08	0.32	D,W	1,5,6
Specific investment, total system ($/Wp)	0.90	0.63	0.45	0.86	1.44	0.27	1.08	E,R,S	1,3,5,6,8,9
Specific investment, total system (million $/MW)	1.08	0.76	0.54	1.03	1.73	0.32	1.30	P	1,3,5,6,8,9

References:

1 MEMR Focus Group Discussions with various stakeholders for the purposes of updating the Technology Catalogue in 2023
2 Data analysed from www.renewables.ninja for multiple locations in Indonesia.
3 IRENA, Renewable Power Generation Costs in 2022, 2023
4 Cirata 1 MW Solar PV O&M and Financial Perspective, Sharing Experience. PJB.
5 The Danish Energy Agency, Technology data for generation of electricity and district heating, 2023.
6 USAID, Panduan Perencanaan dan Pemanfaatan PLTS ATAP DI INDONESIA, 2020
7 PVGIS © Europeen Communitees 2001-2012.
8 World Energy Outlook 2022, IEA 2023
9 IRENA, Future of Solar PV - Deployment, investment,technology, grid integration and socio-economic aspects, 2019

Notes:

A Listed as MWe. The MWp will depend on the DC/AC siizing factor

B See "PV module conversion efficiency (%)". The improvement in technology development is also captured in capacity factor, investment costs and space requirement.

C The generation from a PV system reflects the yearly and daily variation in solar irradiation. It is possible to curtail solar, and this can be done rapidly.

D The share of different elementes of the total system costs are based on a general assumption on a differences from utility scale systems, which is then applied to the full system costs.

E Investment cost include the engineering, procurement and construction (EPC) cost. See description under Methodology.

F The global horizontal irradiation is a measure of the energy resource potential available and depends on the exact geographical location. 1700 kWh/m2 corresponds to a resource slightly above the median value in Java. The range of GHI across the country ranges from 1330 kWh/m2 to 2200 kWh/m2.

G The DC/AC equals module peak capacity Wp divided by plant capacity We(output of the inverter). The sizing factor is chosen according to the desired utilisation/loading of the inverter which can also reflect a desire to maximise the energy production from a given (restricted) AC-capacity.

H The transposition factor describes the increase in the sunlight energy that can be obtained by tilting the module with respect to horizontal and reduction in received energy when the orientation deviates from South. The TF factor is set to the same value for all years and sizes of the system, as it is not the technical factors of the system, which determine the TF. In Indonesia the TF factor for fixed systems is very low, adding only 0-1 % to the production.

I The performance ratio is an efficiency measure which takes the combined losses from incident angle modifer, inverter loss, PV systems losses and non-STC corrections and AC grid losses into account. The Incident Angle Modifier (IAM) loss represents the total yearly solar energy that is reflected from the glass when the angle of incidence is different from the perpendicular (the reflections at a normal incidence is already included in the STC efficiency). PV systems losses and non- STC corrections are calculated by simulating a model-year where corrections are made hour-by-hour due to the fact that the actual operation does not take place under STC conditions. Additionally, electrical losses in cables are included. The inverter loss includes the Maximum Power Point Tracking (MPPT) efficiency and is averaged over typical load levels. An addition to the ratio is the added benefit of having bifacial modules which raise the generation by 5%.

J The full load hours is defined as the peak full load hours*DC/AC sizing factor

K The number of full load hours is calculated based on the other values in the table. The formula is: Peak full load hours = Global horizontal irradiance * transposition factor * performance ratio.

L Capacity factor = Full load hours / 8760.

M The capacity factor or full load hours depend greatly on the global horizontal irradiance at the specific plant site. For sites significantly different from the 1700 kWh/m2/year solar irradiation mentioned here, the caacity factors should be adjusted accordingly.

P The "specific investment, total system per rated capacity W(AC)" is calculated as "specific investment, total system per Wp(DC)" multiplied by the sizing factor.

Q The cost of O&M includes insurance and regular replacement of inverters, technical operation, preventive maintenance, commercial operation, corrective maintenance, insurance, greenkeeping and security. O&M costs are assumed to decrease slower than for equipments. Reported values have a wide range so a +/- 50% interval is suggested for the uncertainty intervals.

R Invstment cost projections and future unertainty ranges are assumed to be similar to the ones for ground-mounted plants and is based on a continued cost reduction estimated from a number of sources, incl. ref. 1, 4, 8, 9.

S For 2023, uncertainty ranges are based on cost spans of various sources

T PV module conversion efficiency (%) is the ration of the energy from the sun that hits the solar panel that is coverted into DC eletricity in the module.

V The space requirement is reduced because of the improved efficiency of the modules, assuming that total area decrese by only 95 % of the decreased demand for modul area.

W The cost of labour and the installation performance is not expected to improve in the same extent as the costs for the equipment. Therefore, the share of installation cost would increase over the years.

X Yearlly outage time is assumed to be 0,5 % equale approxemately 2 hour.

Technology

Technology	PV Floating, utility-scale, grid connected								
	2023	2030	2050	Uncertainty (2023)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for total power plant (MWe)	30	80	100					A	1
Electricity efficiency, net (%), name plate	-	-	-					B	
Electricity efficiency, net (%), annual average	-	-	-					B	
Forced outage (%)	-	-	-						
Planned outage (weeks per year)	-	-	-						
Technical lifetime (years)	27	30	35	25	30	28	42		1
Construction time (years)	0.5	0.5	0.5	0.3	1.0	0.2	1.0		1
Space requirement (1000 m^2/MWe)	8.3	7.5	6.7	7.2	10.0	5.0	9.0	V	9
Additional data for non thermal plants									
Capacity factor (%), theoretical	21.1	21.7	22.8	14.0	22.0	16.0	23.0	M,L	1,2,4
Capacity factor (%), incl. outages	21.0	21.6	22.7	14.0	22.0	16.0	23.0	M,L,X	1,2,4
Ramping configurations									
Ramping (% per minute)	-	-	-	-	-	-	-	C	
Minimum load (% of full load)	-	-	-	-	-	-	-	C	
Warm start-up time (hours)	-	-	-	-	-	-	-	C	
Cold start-up time (hours)	-	-	-	-	-	-	-	C	
Environment									
PM 2.5 (gram per Nm^3)	0	0	0						
SO_2 (degree of desulphuring, %)	0	0	0						
NO_X (g per GJ fuel)	0	0	0						
CH_4 (g per GJ fuel)	0	0	0						
N_2O (g per GJ fuel)	0	0	0						
Financial data									
Nominal investment (M$/MWe)	1.20	0.74	0.48	1.15	1.90	0.25	0.60	E,R,S	1,3,8,11,12
- of which equipment	90%	86%	82%						1,3,6
- of which installation	10%	14%	18%					W	1,3,6
Fixed O&M ($/MWe/year)	9,000	7,500	6,100	4,500	13,500	3,100	9,200	Q	3
Variable O&M ($/MWh)	0	0	0						
Start-up costs ($/MWe/start-up)	0	0	0						
Technology specific data									
Global horizontal irradiance (kWh/m2/y)	1,700	1,700	1,700	1,300	2,200	1,300	2,200	F,M	1,2,7
DC/AC sizing factor (Wp/W)	1.20	1.20	1.20					G	1,5
Transposition Factor for fixed tilt system	1.01	1.01	1.01					H	7
Performance ratio	0.90	0.95	0.97					I	1,4,5
PV module conversion efficiency (%)	0.21	0.23	0.26					T	1,3,5
Inverter lifetime (years)	12.50	15.00	15.00						1,5
Output									
Full load hours (kWh/kW)	1,850	1,900	2,000					J, L	
Peak power full load hours (kWh/kWp)	1,550	1,600	1,650					K, L	
Financial data									
PV module & inverter cost ($/Wp)	0.54	0.32	0.20	0.51	0.86	0.12	0.25		1,3,6
Balance Of Plant cost ($/Wp)	0.36	0.21	0.13	0.34	0.58	0.08	0.06		1,3,6
Installation and other cost ($/Wp]	0.10	0.09	0.07	0.09	0.16	0.04	0.19		1,3,6
Specific investment, total system ($/Wp)	1.00	0.62	0.40	0.95	1.60	0.24	0.50	E,R,S	1,3,8,11,12
Specific investment, total system (M$/MW)	1.20	0.74	0.48	1.14	1.92	0.29	0.60	P	1,3,8,11,12

References:

1 MEMR Focus Group Discussions with various stakeholders for the purposes of updating the Technology Catalogue in 2023

2 Data analysed from www.renewables.ninja for multiple locations in Indonesia.

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4 Benefits of pairing floating solar photovoltaics with hydropower reservoirs in Europe 2023, https://www.sciencedirect.com/science/article/pii/S136403212200870X?via%3Dihub

5 The Danish Energy Agency, Generation of electricity and district heating, 2020.

6 M Rosa-Clot and G.M. Tina, Levelized Cost of Energy (LCOE) Analysis

7 PVGIS © Europeen Communitees 2001-2012.

8 World Energy Outlook 2022, IEA 2023

9 Iselectric brochure. Last accessed: September 2020

10 The Energy and Resources Institute, Floating Solar Photovoltaic (FSPV): A Third Pillar to Solar PV Sector?, 2019

11 A A Untoro et al, Study of Economic Viability of Floating Photovoltaic Electric Power in Indonesia, 2021

12 International Bank for Reconstruction and Development, Where Sun Meets Water: Floating Solar Market Report, 2018

13 NREL, Floating Photovoltaic System Cost Benchmark: Q1 2021 Installations on Artificial Water Bodies, 2021

14 IRENA, Future of Solar PV - Deployment, investment,technology, grid integration and socio-economic aspects, 2019

Notes:

A Listed as MWe. The MWp will depend on the DC/AC siizing factor

B See "PV module conversion efficiency (%)". The improvement in technology development is also captured in capacity factor, investment costs and space requirement.

C The generation from a PV system reflects the yearly and daily variation in solar irradiation. It is possible to curtail solar, and this can be done rapidly.

E Investment cost include the engineering, procurement and construction (EPC) cost. See description under Methodology.

F The global horizontal irradiation is a measure of the energy resource potential available and depends on the exact geographical location. 1700 kWh/m2 corresponds to a resource slightly above the median value in Java. The range of GHI across the country ranges from 1330 kWh/m2 to 2200 kWh/m2.

G The DC/AC equals module peak capacity Wp divided by plant capacity We(output of the inverter). The sizing factor is chosen according to the desired utilisation/loading of the inverter which can also reflect a desire to maximise the energy production from a given (restricted) AC-capacity.

H The transposition factor describes the increase in the sunlight energy that can be obtained by tilting the module with respect to horizontal and reduction in received energy when the orientation deviates from South. The TF factor is set to the same value for all years and sizes of the system, as it is not the technical factors of the system, which determine the TF. In Indonesia the TF factor for fixed systems is very low, adding only 0-1 % to the production.

I The performance ratio is an efficiency measure which takes the combined losses from incident angle modifer, inverter loss, PV systems losses and non-STC corrections and AC grid losses into account. For Floating PV, a 5% improvement in performance is included due to effects of cooling from the water service, as described in reference 4.
The Incident Angle Modifier (IAM) loss represents the total yearly solar energy that is reflected from the glass when the angle of incidence is different from the perpendicular (the reflections at a normal incidence is already included in the STC efficiency). PV systems losses and non- STC corrections are calculated by simulating a model-year where corrections are made hour-by-hour due to the fact that the actual operation does not take place under STC conditions. Additionally, electrical losses in cables are included. The inverter loss includes the Maximum Power Point Tracking (MPPT) efficiency and is averaged over typical load levels. An addition to the ratio is the added benefit of having bifacial modules which raise the generation by 5%.

J The full load hours is defined as the peak full load hours*DC/AC sizing factor

K The number of full load hours is calculated based on the other values in the table. The formula is: Peak full load hours = Global horizontal irradiance * transposition factor * performance ratio.

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M The capacity factor or full load hours depend greatly on the global horizontal irradiance at the specific plant site. For sites significantly different from the 1700 kWh/m2/year solar irradiation mentioned here, the caacity factors should be adjusted accordingly.

P The "specific investment, total system per rated capacity W(AC)" is calculated as "specific investment, total system per Wp(DC)" multiplied by the sizing factor.

Q The cost of O&M includes insurance and regular replacement of inverters, technical operation, preventive maintenance, commercial operation, corrective maintenance, insurance, greenkeeping and security. O&M costs are assumed to decrease slower than for equipments. Reported values have a wide range so a +/- 50% interval is suggested for the uncertainty intervals.

R Invstment cost projections and future unertainty ranges are assumed to be similar to the ones for ground-mounted plants and are based on a continued cost reduction estimated from a number of sources.

S For 2023, uncertainty ranges are based on cost spans of various sources.

T PV module conversion efficiency (%) is the ration of t Is the ration of the energy from the sun that hits the solar panel that is coverted into DC eletricity in the module

U Estimations of space requirements are based on the mapping of the average polygonal area occupied by PV arrays and electrical equipments like inverter pad of existing floating PV plants in Indonesia and Singapore.

V The space requirement is reduced because of the improved efficiency of the modules, assuming that total area decrese by only 90 % of the decreased demand for module area.

W The cost of labour and the installation performance is not expected to improve in the same extent as the costs for the equipment. Therefore, the share of installation cost would increase over the years. The cost of instalation is expected to be 10 % lower than for Ground mounted, based on [13]

X Yearlly outage time is assumed to be 0,5 % equale approxemately 2 hours.

4. Wind Turbines

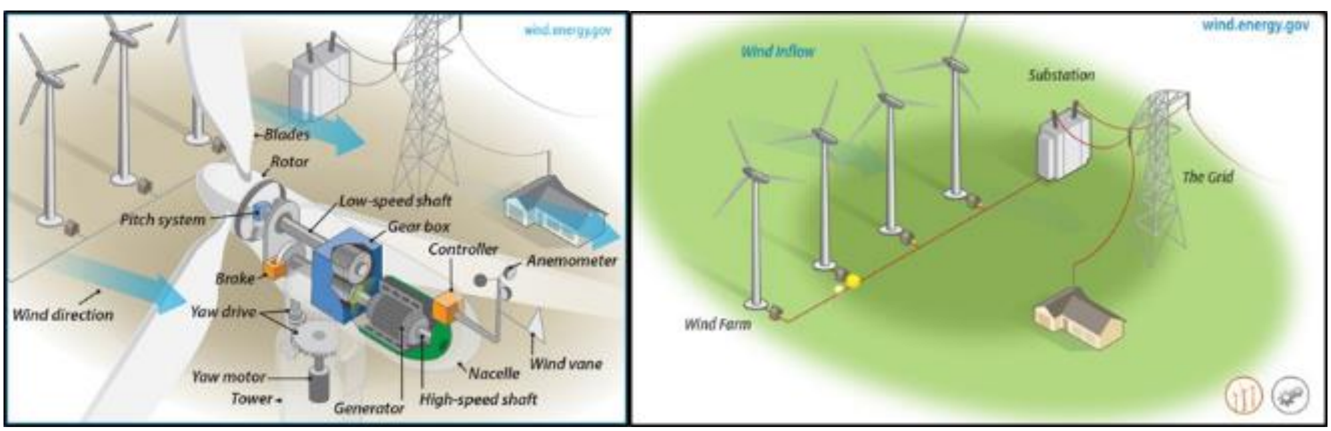
Brief technology description
Wind power has become a widespread renewable energy source in the past decades. The factors behind this growth are the significant improvements in efficiency, the development of structured manufacturing and supply chains and the overall technological reliability.

Wind energy is exploited through turbines (typically with horizontal axis) installed in locations where the wind resource ensures high yearly yields. Wind power can be classified in two main broad categories:

- Onshore wind
- Offshore wind (of which floating wind is a sub-category)

This catalogue describes onshore and offshore wind turbines, which are currently the most attractive option for Indonesia. The typical large wind turbine being installed today is a horizontal-axis, three bladed, upwind, grid connected turbine using active pitch, variable speed and yaw control to optimize generation at varying wind speeds. Generally speaking, offshore wind turbines tend to be larger than onshore wind turbines, since the blades and towers are easier to transport, and increased scale decreases cost on a per MW basis. Offshore wind was also considered, due to the deep waters off the coast of Southern Indonesia, however floating turbines have not been included as the offshore wind speeds are too low to justify the extra cost of floating offshore wind in the near or medium term.

Wind turbines work by capturing the kinetic energy in the wind with the rotor blades and transferring it to the drive shaft. The drive shaft is connected either to a speed-increasing gearbox coupled with a medium- or high-speed generator, or to a low-speed, direct-drive generator. The generator converts the rotational energy of the shaft into electrical energy. In modern wind turbines, the pitch of the rotor blades is controlled to maximize power production at low wind speeds, and to maintain a constant power output and limit the mechanical stress and loads on the turbine at high wind speeds. A general description of the turbine technology and electrical system, using a geared turbine as an example, can be seen in the figure below.



General turbine technology and electrical system

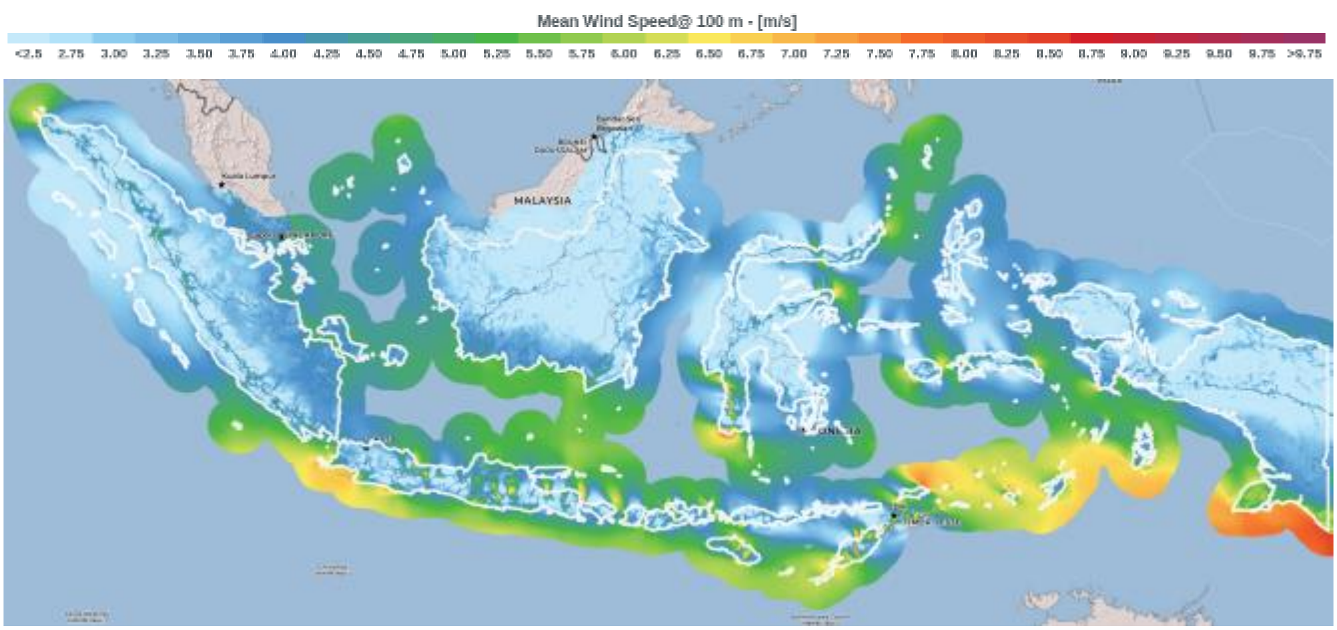
Wind turbines are designed to operate within a wind speed range, which is bounded by a low “cut-in” wind speed and a high “cut-out” wind speed. When the wind speed is below the cut-in speed the energy in the wind is too low to be utilized. When the wind reaches the cut-in speed, the turbine begins to operate and produce electricity. As the wind speed increases, the power output of the turbine increases, and at a certain wind speed the turbine reaches its rated power. At higher wind speeds, the blade pitch is controlled to maintain the rated power output. When the wind speed reaches the cut-out speed, the turbine is shut down or operated in a reduced power mode to prevent mechanical damage.

Three major parameters define the design of a wind turbine. These are hub height, nameplate capacity (or rated power) and rotor diameter. The last two are often combined in a derived metric called "specific power", which is the ratio between nameplate capacity and swept area. The specific power is measured in W/m^2.

The wind turbine design depends on the wind conditions at the site. In the IEC61400-1:2005, the International Electrotechnical Commission (IEC) defines three types of wind classes, as reported in the table below.

	Class I (High Wind)	**Class II (Medium Wind)**	**Class III (Low Wind)**
Average annual wind speed at hub height [m/s]	10	8.5	7.5
50-year extreme wind speed over 10 minutes [m/s]	50	42.5	37.5
50-year extreme wind speed over 3 seconds [m/s]	70	59.5	52.5

The map below illustrates wind resource distribution across Indonesia. Optimal sites, predominantly in the South, exhibit modest wind resources as classified by the IEC. When comparing the data in the table above with the map, it becomes evident that Indonesia possesses limited onshore wind resources, with only a handful of locations suitable for class III turbines.



Wind speed at 100m above ground in Indonesia. Source: Global Wind Atlas.

The turbine design differs consistently depending on the type of wind resource. In low-wind (LW) sites, turbines are generally taller and have a larger swept area, leading to a lower specific power. In this way, turbines access higher wind speeds (the wind speed increases with height above ground) and manage to convert more wind power into electricity. In fact, the wind power picked up by the turbine is proportional to the swept area *A* and the third power of the wind speed *v*:

$$P = 0.5 \cdot \rho \cdot A \cdot v\hat{}3$$

ρ (rho) being the air density. The real electric power delivered to the grid is affected by mechanical and electrical conversion efficiencies. With a different turbine design, LW turbines can reach an annual production comparable to that of HW turbines which, on the contrary, are physically smaller. For the above-mentioned reasons, this catalogue presents only data for LW turbines.

Onshore wind turbines can be installed as single turbines, in clusters or in larger wind farms. Additional losses due to wake effects can occur in large wind farms.

Offshore wind farms must withstand the harsh marine environment and this drive costs up. The electrical and mechanical components in the turbines need additional corrosion protection and the offshore foundations are costly. The high cost of installation, results in much higher investment costs than for onshore turbines of similar size. However, the offshore wind resource is better, and possible onshore sites are limited. What this means is that offshore wind turbines require high wind speeds to be cost viable. Unfortunately, Indonesia has low offshore wind speeds as well, making the case for offshore wind difficult. Furthermore, in the southern area where it is windier, the waters are deep, creating the need for floating offshore turbines. However, technological innovations such as floating foundations may reduce the costs in the future and allow offshore wind farms to be commissioned in deep water areas as well, though this technology is not yet deployed on a commercial basis.

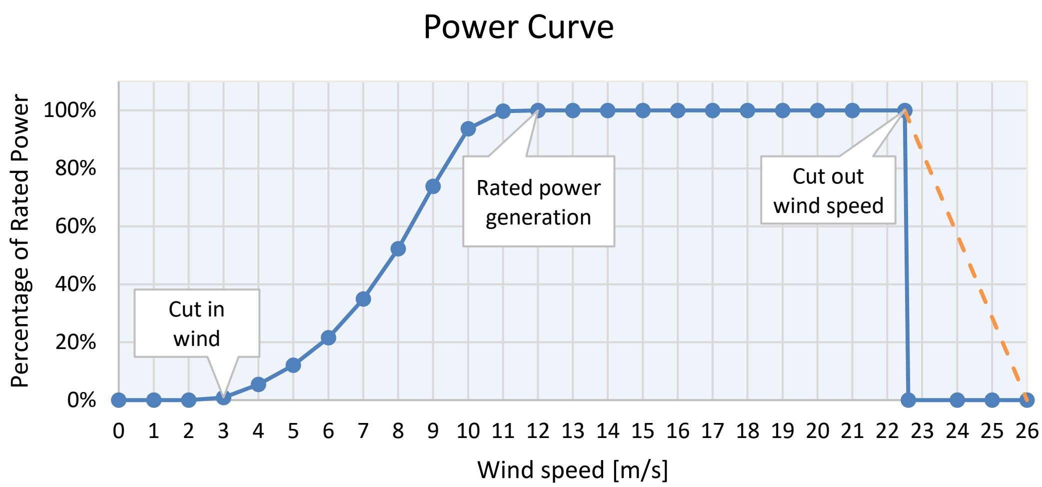
Offshore wind farms are typically built with large turbines in considerable numbers.

Commercial wind turbines are operated unattended and are monitored and controlled by a supervisory control and data acquisition (SCADA) system.

Input

Input is wind.

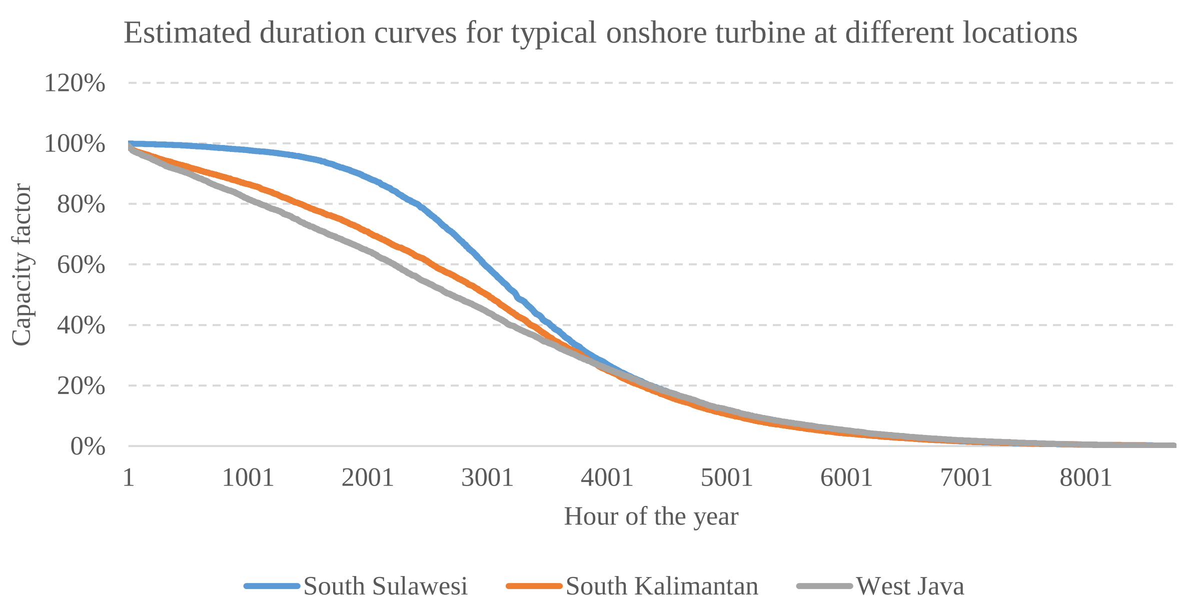
Cut-in wind speed: 3-4 m/s. Rated power generation wind speed is 10-12 m/s. Cut-out or transition to reduced power operation at wind speed around 22-25 m/s for onshore and 25-30 m/s for offshore. In the future, it is expected that manufacturers will apply a soft cut-out for high wind speeds (indicated with dashed orange curve in the figure) resulting in a final cut-out wind speed of up to 30 m/s for onshore wind turbines. The technical solution for this is already available (ref. 17).



Power curve for a typical wind turbine.

Output
The output is electricity.

The wind resource in Indonesia is scarce. There are however locations, particularly in Southern Sulawesi, South Kalimantan and Java, which demonstrate attractive wind speeds. Based on data from the Indonesian wind resource map the typical capacity factor for a modern Class III onshore turbine located at these good sites in Indonesia will be in the range of 30% corresponding to around 2600 annual full load hours. The estimate is based on the power curve for a low-wind speed turbine at 100 m hub height. In the figure below, four different duration curves from different locations are plotted, representing the ranges of duration curves found.



Onshore Duration Curves for different Indonesian locations based on the Indonesian wind resource map at 100 m (ref. 1) and on the power curve for a low wind speed turbine (calculations are based on the power curve of a Vestas V126, 3.45 MW).

The annual energy output of a wind turbine is strongly dependent on the average wind speed at the turbine location. The average wind speed depends on the geographical location, the hub height, and the surface roughness. Hills and mountains also affect the wind flow, and therefore steep terrain requires more complicated models to predict the wind resource, while the local wind conditions over a flat terrain are normally dictated by the surface roughness. Also, local obstacles like forests and, for small turbines, buildings and hedges reduce the wind speed, as do wakes from neighbouring turbines. Due to the low surface roughness at sea, the variation in wind speed with height is small for offshore locations; the increase in wind speed from 50m to 100m height is around 8%, in comparison to 20% for typical inland locations.

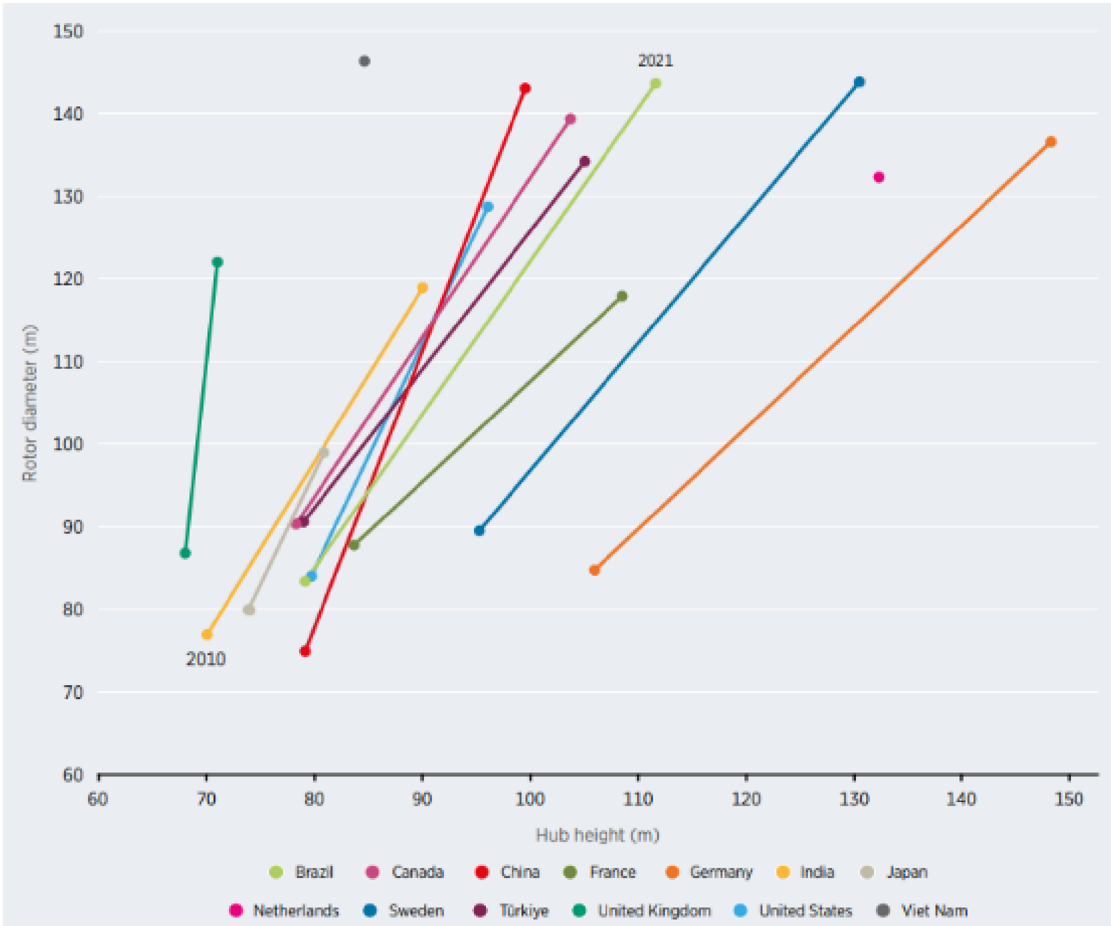
Typical capacities

Wind turbines can be categorized according to the nameplate capacity. At present time, new onshore installations are in the range of 3 to 6 MW and typical offshore installations are in the range of 8-12 MW. However, turbine capacities of offshore wind turbines are expected to increase in the near future, and current projects are already approaching the 15 MW range (ref. 22). As illustrated before, the nameplate capacity strongly depends on the wind class of the turbine (i.e. the lower the wind speed, the lower the optimal nameplate capacity).

Two primary design parameters define the overall production capacity of a wind turbine. At lower wind speeds, the electricity production is a function of the swept area of the turbine rotor. At higher wind speeds, the power rating of the generator defines the power output. The interrelationship between the mechanical and electrical characteristics and their costs determines the optimal turbine design for a given site.

The size of wind turbines has increased steadily over the years (see figure below). Larger generators, larger hub heights and larger rotors have all contributed to increase the electricity generation from wind turbines. Lower specific power improves the capacity factor (that is, the yearly energy yield), since power output at wind speeds below rated power is directly proportional to the swept area of the rotor (as seen in the equation for electrical power generated by the wind turbine).

However, installing large onshore wind turbines requires well-developed infrastructure to be in place, in order to transport the big turbine structures to the site. If the infrastructure is not in place, the installation costs will be much higher, and it might be favourable to invest in smaller turbines that the current infrastructure can manage. However, there are cases where such infrastructure is built together with the project, e.g. the Lake Tukana project of Vestas in Kenya (ref. 17).



Onshore wind weighted average rotor diameter and hub height by country, 2010-2021. Source: IRENA's Renewable Power Generation Costs in 2021.

Ramping configurations

Electricity from wind turbines is highly variable because it depends on the actual wind resource available. Therefore, the ramping configurations depend on the weather situation. In periods with calm winds (wind speed less than 4-6 m/s) wind turbines cannot manage the power output in a wide range, but they can provide voltage regulation.

With sufficient wind resources available (wind speed higher than 4-6 m/s and lower than 25-30 m/s) wind turbines can always ramp down, and then be running in power-curtailed mode (i.e. with an output which is deliberately set below the potential output based on the available wind resource).

In general, a wind turbine will run at maximum power according to the power curve and up ramping is only possible if the turbine is operated at a power level below the actual available power (curtailed mode). This mode of operation is technically possible, and in many countries, turbines are required to have this feature. However, the system operator will typically be required to compensate the owner for the reduced revenue (ref. 2).

Generation from wind turbines can be regulated down for grid balancing. The start-up time from no production to full operation depends on the wind resource available.

Some types of wind turbines (DFIG and converter based) also have the ability to provide supplementary ancillary services to the grid such as reactive power control, spinning reserve, inertial response, etc.

Advantages/disadvantages

Advantages:

- No emissions of local pollution from operation.
- No emission of greenhouse gases from operation.
- Stable and predictable costs due to low operating costs and no fuel costs.
- Modular technology allows for capacity to be expanded according to demand, avoiding overbuilds and stranded costs.
- Short lead time compared to most alternative technologies.

Disadvantages:

- Land use:
    - Wind farm construction onshore may require clearing of forest areas.
- Subject to variability of weather conditions.
- Moderate contribution to firm capacity provision compared to thermal power plants.
- Need for regulating power.
- Visual impact and noise.
- Endangerment of animal species affected by the turbine/farm erection.

Environment

Wind energy is a clean energy source. The main environmental concern in Indonesia is the removal of vegetation to make room for onshore wind farms which requires a flat terrain without obstacles.

The visual impact of wind turbines is an issue that creates some controversy, especially since onshore wind turbines have become larger.

Flickering is generally managed through a combination of prediction tools and turbine control. Turbines may in some cases need to be shut down for brief periods when flickering effect could occur at neighbouring residences.

Noise is generally dealt with in the planning phase. Allowable sound emission levels are calculated on the basis of allowable sound pressure levels at neighbours. In some cases, it is necessary to operate turbines at reduced rotational speed and/or less aggressive pitch setting in order to meet the noise requirements.

The typical space requirement for a modern wind turbine is in the range of 2500m^2. However, a much larger area is needed to dampen the noise produced by a turbine. Other ways to assess the space requirement of a wind turbine is to look at existing wind farms and measure the area in terms of MW/km^2. Doing this will find that for an average onshore wind farm, the MW/km^2 (also called power density) is around 20 MW/km^2 (Ref. 23).

The environmental impact from the manufacturing of wind turbines is moderate and is in line with the impact of other normal industrial production. However, most wind projects require an environmental assessment to understand the overall impact linked to the erection and operation of the turbine. In addition, the mining and refinement of rare earth metals used in permanent magnets is an area of concern (ref. 3,4,5). Life-cycle assessment (LCA) studies of wind farms have concluded that environmental impacts come from three main sources:

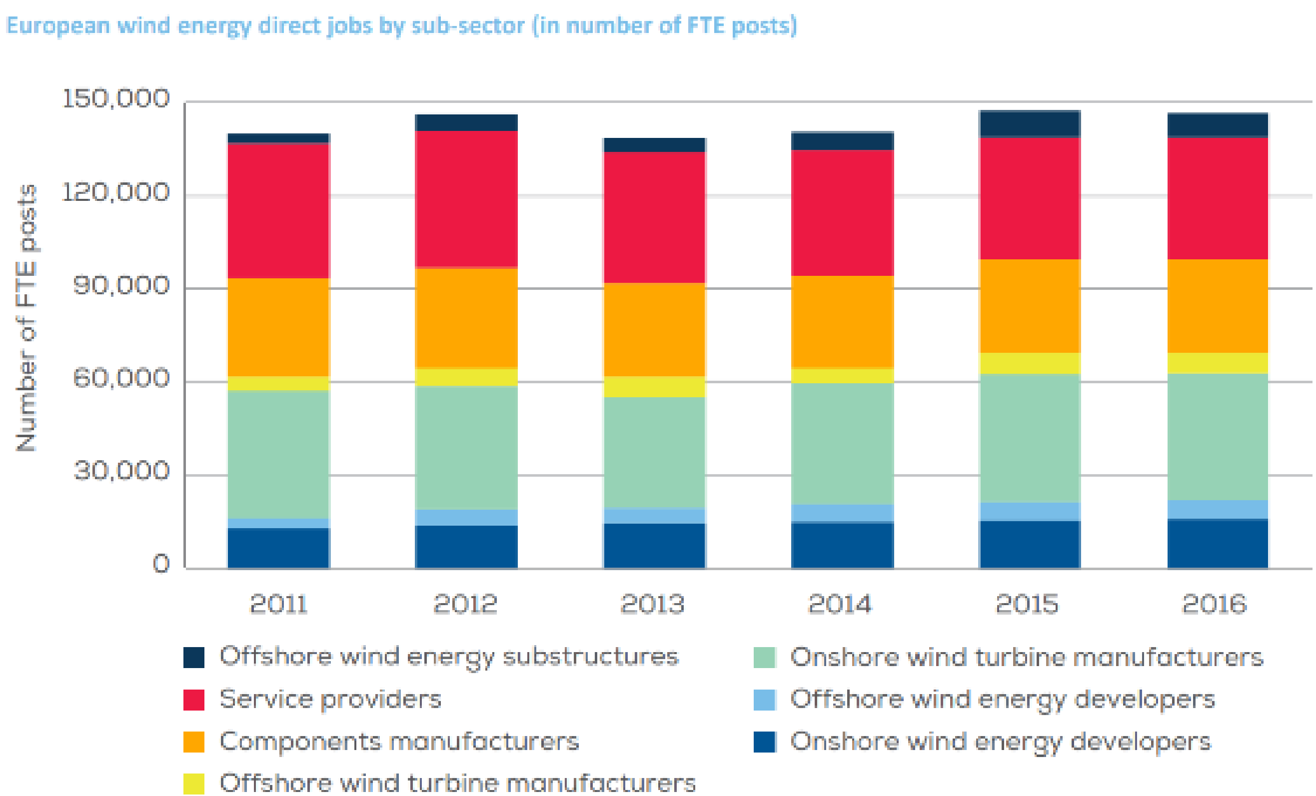
- bulk waste from the tower and foundations, even though a high percentage of the steel is recycled.
- hazardous waste from components in the nacelle.
- greenhouse gases (e.g. CO_2 from steel manufacturing).

Employment

In India, a total instalment of 22,465 MW onshore wind power, as of 2014, has resulted in an employment of around 48,000 people, meaning that an installed MW of wind power generates around 2.1 jobs locally in onshore wind power (ref. 7,8). The 300 MW Lake Turkana onshore wind project in Kenya is employing 1,500 workers during construction (October 2014-July 2017) and 150 workers at the operational state (from September 2016 onwards), of whom three quarters will be from the local communities, thus generating 0.5 long term jobs per MW (ref. 15).

The figure below illustrates the distribution of direct employment in different industries related to wind power in Europe. When considering the indirect employment numbers, the figures almost double, such that in the year 2016, the wind energy industry in Europe generated 146,545 direct jobs and 116,166 indirect jobs. This can be seen in the figure below.

Service providers include transportation of equipment, engineering and construction, maintenance, research and consultancy activities, financial services.



Direct employment (Full Time Employment) by company type related to the wind industry in Europe (ref. 6).

Research and development
Wind power technologies are commercial, but still under constant improvement (category 3). The R&D potential lies in the following (ref. 3,9):

- Reduced investment costs resulting from improved design methods and load reduction technologies.
- More efficient methods to determine wind resources, incl. external design conditions, e.g. normal and extreme wind conditions.
- Improved aerodynamic performance.
- Reduced O&M costs resulting from improvements in wind turbine component reliability.
- Development in ancillary services and interactions with the energy systems.
- Improved tools for wind power forecasting and participation in balancing and intraday markets.
- Improved power quality. Rapid change of power in time can be a challenge for the grid.
- Noise reduction. New technology can decrease the losses by noise reduced mode and possibly utilize good sites better, where the noise sets the limit for number of turbines.
- Storage technologies can improve value of wind power significantly, but is expensive at present.
- Offshore:
  - Further upscaling of wind turbines.
  - New foundation types suitable for genuine industrialization, among which floating substructures.
  - Development of 66kV electrical wind farm systems as alternative to present 33 kV.
  - Improved monitoring in operational phase for lowering availability losses and securing optimal operation.

Investment cost estimation, overview – Onshore Wind
The experience with wind power deployment in Indonesia is limited and therefore there is not a large amount of statistical cost data available that can be highly relied upon.

In 2017, PLN assumed a planning price of 1.75 mill. USD/MW for Indonesia (ref 12). Vestas' assessment in 2017 was that the investment cost for the first projects in Indonesia would be 1.4-1.5 mill. USD/MW. Considering the variation in costs across countries/regions reported above, the value of 1.5 mill. USD/MW is considered the best estimate for a planning cost for onshore large-scale wind turbines erected in Indonesia by 2023.

Onshore wind turbines can be seen as off-the-shelf products, but technology development continues at a considerable pace, and the cost of energy has continued to drop. While price and performance of today's onshore wind turbines are well known, future technology improvements, increased industrialization, learning in general and economies of scale are expected to lead to further reductions in the cost of energy.

Full-load-hours (FLH) are expected to continue to increase due to lower specific power, but also increased hub heights, especially in the regions with low wind, and improvement in efficiency within the different components is expected to contribute to the increase in production. Based on the projection in ref. 10 we assume a 2% increase in capacity factor by 2030 compared to 2020 and 4% improvement by 2050.

Investment costs [MUSD$_{2022}$/MW]		2020	2023	2030	2050
Catalogues	**New Catalogue (2023)**	-	**1.65**	**1.20**	**0.95**
	Existing Catalogue (2020)	1.72	-	1.46	1.23
Indonesia data	MEMR FGDs 2023[1]	1.08-3.23	1.60-2.21		
International data	Technology catalogue for Vietnam 2023	1.50		1.28	1.08
	IRENA[2] (weighted average of India and China 2022)		1.1		
	IEA WEO 2023 (average of India and China)		1.11	1.04	0.98
	IEA WEO 2023 (average of Europe and US)		1.44	1.40	1.33
	NREL ATB[4]		1.63	1.29	1.04
	Lazard		1.03-1.70		
Projection	Development curve – cost trend [%]	-	100%	79%	64%

[1]*Ministry of Energy and Mineral Resources Focus Group Discussions 2023. Estimates generally refer to wind farms with smaller capacity than the 70 MW assumed for this publication and therefore also higher costs per MW.*
[2]*IRENA (2022), Renewable power generation costs in 2022, International Renewable Energy Agency, Abu Dhabi.*
[4]*2023 Annual Technology Baseline Workbook Mid-year update 2-15-2023 based on US class 9 wind resource (weighted average wind speed of 6.2 m/s)*

Investment cost estimation, overview – Offshore Wind

The cost of offshore wind has fallen dramatically during the last decade as the technology has matured. However, its cost is more difficult to determine as distance to shore, water depth, and ocean floor quality vary from location to location. In addition, during the last 3 years (2020 to 2023) the cost of offshore wind has actually increased due to supply chain issues and inflation. Currently, there is large offshore wind investment in the North Sea in Europe and the East and South China Seas, where water depths are frequently below 50m and local offshore wind manufacturing exists. In Indonesia on the other hand, excluding the Southeastern coast of Papua Selatan, there is no large offshore areas with water depth lower than 50m and average wind speeds above 7 m/s. The Southeastern coast of Paupa Selatan has shallow waters and winds speeds just above 7 m/s, however these winds are still much weaker than the winds in the North Sea in Europe, where wind speeds are typically above 9.5 m/s.

All this is to say that, when evaluating offshore wind in Indonesia, Capex and CF will be different from the parts of the world where there is currently offshore wind investment, as the wind quality and water depth are both worse in Indonesia than in these areas.

EU and Chinese Capex data is lower than what is assumed in the catalog, as the water depths in Indonesia are higher than these areas. Japan has deep waters as well, the impact of which can be seen in the table above under the IRENA 2020 numbers. The capex numbers assumed in this catalogue are geared towards the Southeastern coast of Paupa Selatan, with water depths between 20 and 50m.

Investment costs [MUSD$_{2022}$/MW]		2020	2023	2030	2050
Catalogues	**New Catalogue (2023)**	-	**4.10**	**3.39**	**2.87**
	Existing Catalogue (2020)	3.99	-	3.39	2.87
Indonesia data					
International data	Technology catalogue for Vietnam 2023	3.15		2.15	1.70
	IRENA[1] (weighted average of Asia 2022)		3.16		
	NREL ATB[2]	4.44	3.72	3.35	2.85
Projection	Development – cost trend [%] compared to 2023	-	100%	75%	64%

[1]IRENA (2022), Renewable power generation costs in 2022, International Renewable Energy Agency, Abu Dhabi.
[2]2022 v3 Annual Technology Baseline Workbook Mid-year update 2-15-2023 (2) - NREL ATB numbers come from the Class 6 offshore turbine, which assumes 33m average water depth, 74km from shore, and CF of 39%.

Examples of current projects

Large Scale Wind Power Plant: Tolo 1 and Sidrap Wind Power Plants (Ref. 18)

The Tolo 1 Jeneponto Power Plant is a wind power plant located in Binamu District, Jeneponto Regency, South Sulawesi. This power plant has 20 Siemens Gamesa Wind Turbine Generators (WTG) with 133 meters high and 63 meters long propellers. Each generator has a capacity of 3.6 MW; thus, the capacity of the farm is 72 MW. The power plant is estimated to generate 198.6 GWh of electricity annually with wind speeds of 6 m/s. The wind farm was developed by Equis Energy and was installed by late 2017 (COD May 2019). The project itself started on July 2, 2018 and costs US $ 160.7 million. Prior to that, the government had signed a Power Purchase Agreement (PPA) for this power plant on November 14, 2016 with a 30-year contract period. The accepted selling price is 11.85 cents per kWh. During the construction period of this project 250 domestic workers, 122 of them are local workers and 27 foreign workers were engaged. During the operation, it is planned that only 1 foreign worker will be employed. The wind farm covers an area of 60 hectares.

Tolo 1 Wind Power Plant at Jeneponto, South Sulawesi (Ref. 18)

The Sidrap 1 Wind Power Plant is the first commercial-scale wind-power plant in Indonesia and located at Sidrap, South Sulawesi. Sidrap 1 wind power has a capacity of 75 MW and has been operating well and has a high level of reliability. Sidrap 1 was developed by PT UPC Sidrap Bayu Energi which is an SPV company formed by the UPC Renewables consortium with an investment cost of 150 million USD and creates a workforce of 709 people, consisting of 95% Indonesian Workers and 5% Foreign Workers. It was erected during 2016 – 2017 (COD: March 2018). Sidrap 1 was established on an area of 100 hectares with 30 units of Gamesa Wind Turbine Generators (WTG) or windmills that have a tower height of 80 meters and a propeller length of 57 meters. The capacity of each of them is 2.5 MW. The price of electricity for the 75 MW Sidrap 1 was agreed at US 11 cents per kWh. This price is corresponding to 85% of PLN's cost of electricity production (BPP) in the South Sulawesi.

Sidrap 1 Wind Power Plant at Sidrap, South Sulawesi (Ref. 19)

Small Scale Wind Power Plant: Baron Technopark

Baron Teknopark is an area designed as a center for R&D, Training and Promotion / Dissemination of Technology Utilizing New and Renewable Energy. It is located at Baron, Yogyakarta. One of its research facilities is a 2 x 5 kW wind power plant. This small-scale wind power plant is just for research purposes.

Baron Wind Power Plant in Yogyakarta. (Ref. 20)

Sidrap Wind Farm (ref 24)
The 75 MW Sidrap Wind Farm project is located in the Sidrap region, in South Sulawesi, Indonesia. The project is Indonesia's first utility scale wind farm and began providing power to the Southern Sulawesi PLN grid in March 2018. The project uses 30 Gamesa 2.5 MW turbines. The Sidrap Project is located on a group of windy ridges. The location has strong winds along with a supportive local community that welcomed the project. Numerous jobs in both project development and construction have been created with the majority being filled by the local citizens from the region.

Sidrap completed construction on the April 5th, 2018 and was inaugurated by the President of Indonesia, Joko Widodo on July 5th, 2018. Notably, Sidrap was completed on time and on budget. The operation profile continues to meet or exceed expectations. The Sidrap project is owned in partnership with AC Energy Holding (an Ayala Corporation subsidiary) with bank finance by the U.S. Overseas Private Investment Corporation.

Jeneponto (ref 25)
The domestic component level (TKDN) of the Tolo PLTB, which is controlled by a private power developer (Independent Power Producer/IPP), is roughly 40%. With a height of 133 meters (m) and a propeller length of 63 meters, each of the 20 installed turbines can transmit 3.6 MW of power, bringing the total capacity to 72 MW. This PLTB has the capacity to electrify the equivalent of 300,000 houses with 900 VA users.

PLTB Lombok UPC (ref 26)
West Nusa Tenggara (NTB) Province and UPC Renewables have signed a Memorandum of Understanding (MoU) to encourage green energy investment for the East Lombok 115 MW Wind Power Plant (PLTB) project, which will include Indonesia's first large-scale Battery Energy Storage System (BESS). The fulfilment of numerous essential permissions, including the AMDAL and Environmental Permit studies, signalled the preparedness of the 115 MW East Lombok PLTB Project in January 2021.

PLTB Tanah Laut Adaro (ref 27, 2023)
State Electricity Company (Persero) ("PLN") signed an Electricity Sales and Purchase Agreement ("PJBL") together with Total Eren S.A. ("Total Eren"), PT Adaro Power ("Adaro Power"), and PT Pembangkitan Jawa Bali Investasi ("PJBI"), which includes the construction of a wind power plant ("PLTB") with a capacity of 70 MW and equipped with a battery energy storage system of 10 MW or 10 MWh in Tanah Laut, South Kalimantan.

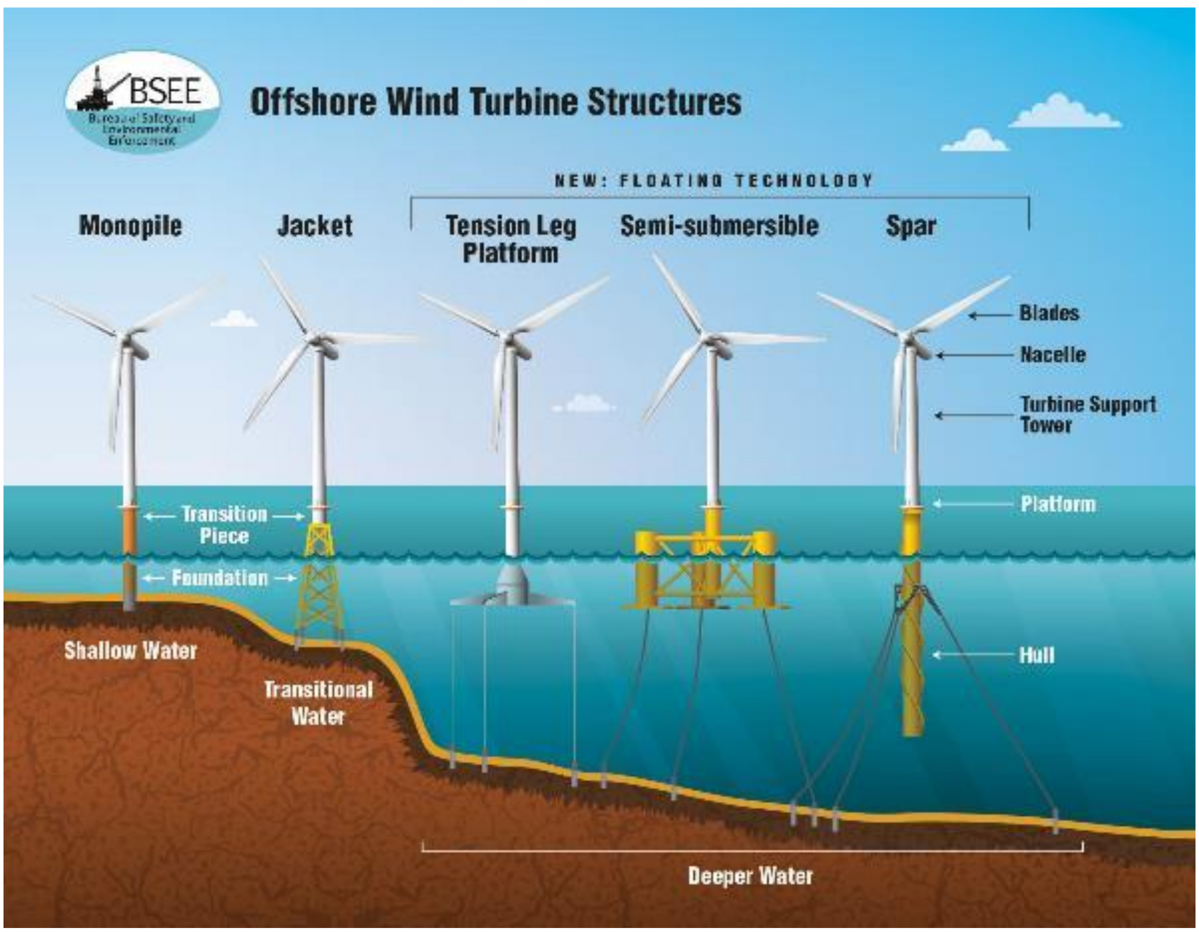
PLTB Tanah Laut Total Arem (ref 28,2023)
PLTB Tanah Laut features a battery energy storage system with a capacity of 10 MW/10 MWh. The benefit of BESS is that it can stabilize the PLTB's energy output, allowing it to deliver a more stable and scalable electrical supply.

Floating offshore wind
Floating offshore wind is in rapid development. While the application of bottom-fixed offshore wind is currently limited to water depths of 60 m or less, floating technologies can in principle be applied at any water depth above 30-40 m. Practical applications are likely to be limited to water depths less than 1000-1500 m due to the cost of mooring systems, but even so IEA has estimated that the commercially viable floating offshore wind resource may exceed the world's total electricity consumption by up to a factor of 10 (ref. 21).

Three main concepts of floating substructures are available, differing in the way they obtain the floating stability that is required to keep the turbine upright under all wind and wave conditions. The spar buoy concept relies on ballast for stability, having the center of gravity of the total assembly below the center of buoyancy. The semisubmersible concept relies on buoyancy for stability. It has lateral columns that penetrate the waterplane and are submerged to a varying degree when the turbine heels over due to bending moments caused by wind and wave loads, and the differences in buoyancy as a function of the submersion of the columns creates the restoring moment. The tension leg or TLP concept relies on the mooring system for stability. It has vertical or near-vertical mooring lines that are kept taut by the buoyancy on the substructure, and bending moments caused by wind and wave loads are countered by a restoring moment arising out of differences in line tension.

Standard offshore wind turbines can be used for floating applications; the only two modifications required are tower reinforcement and motion control software. The tower reinforcement is needed to account for the additional loads caused by tower inclinations and wave-induced accelerations, and the motion control software ensures stability during operation above rated power where standard pitch regulation algorithms lead to low or even negative aerodynamic damping.

In floating wind, the wind turbines are typically installed on the floating substructures at the quayside using land-based cranes. Towing of the fully assembled structure and hook-up to the pre-laid mooring system at the installation site can be carried out with large tugs, anchor handlers or similar vessels of a few thousand tons displacement, thereby eliminating the need for large and expensive installation vessels. A wide range of mooring systems is available, most commonly three or more drag anchors are connected to the floating substructure with a combination of chains and wire ropes. So-called dynamic cables are used as array cables; they are ordinary subsea cables fitted with additional steel wire reinforcement ensuring that bending resulting from substructure movement is kept within a range that minimizes fatigue loading on the cable conductors.



Examples of Offshore wind turbine structures [Ready-to-float: A permanent cost reduction for offshore wind, 2021, https://www.windpowerengineering.com/ready-to-float-a-permanent-cost-reduction-for-offshore-wind/]

During wind and wave conditions where crew transport is considered safe a floating substructure has no noticeable movements, and normal O&M can be carried out using the same vessels and methodologies as for bottom-fixed offshore turbines. Self-hoisting cranes and vessel-mounted cranes with motion control are being developed, but at the present time it is generally assumed that a floating wind turbine will require tow back to port in case of main component replacement.

At the present time, only a limited number of floating substructures have been demonstrated. The first demonstrators were installed around 2010 by Equinor (a spar buoy concept) and Principle Power (a semisubmersible concept), and both of these parties have subsequently demonstrated their technologies in small wind farms. A barge-type variant of the semisubmersible concept was installed by the French company Ideol in 2017, and a spar buoy was installed by the Danish company Stiesdal Offshore Technologies in 2021.

At the present time two Danish companies are active in the development of floating offshore substructures, Stiesdal Offshore Technologies and Floating Power Plant.

Stiesdal has developed the Tetra technology, a fully industrialized manufacturing concept where all substructure components are factory-manufactured and subsequently assembled in the port of embarkation. The manufacturing concept can be applied to all three substructure concepts. In 2021, a first spar-configuration demonstrator fitted with a 3.6 MW 130 m turbine was installed at 200 m water depth at the METCentre test site off the coast of Norway.

Floating Power Plant has developed the FPP Platform, a substructure integrating wind and wave power. A first full-scale demonstration project may be installed at the PLOCAN test site of the Canary Islands as early as 2024. The commercial potential for application of floating offshore wind in Denmark is unknown. For the foreseeable future the large areas of moderate water depth available in the Denmark's exclusive economic zone will be more than adequate for build-out using well-established bottom-fixed technologies. Some future applications in deeper-water parts of Kattegat and the Baltic may be envisaged.

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The description in this chapter is to a great extent from the Danish Technology Catalogue *"Technology Data on Energy Plants - Generation of Electricity and Heat"*. The following sources are used:

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Data sheets

The following pages contain the data sheets of the technologies. All costs are stated in U.S. dollars (USD), price year 2022. The uncertainty is related to the specific parameters and cannot be read vertically – meaning a product with e.g. lower efficiency does not have a lower price.

Technology

Technology	Wind power - Onshore								
	2023	2030	2050	Uncertainty (2023)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	3.5	4.5	6.0						3
Generating capacity for total power plant (MWe)	70	90	120						1
Rotor Diameter (m)	139	178	226						
Hub Height (m)	110	150	180						
Specific Power (W/m2)	230	180	150						
Forced outage (%)	2.5	2.0	2.0						3
Planned outage (weeks per year)	0.16	0.16	0.16	0.05	0.26	0.05	0.26		3
Technical lifetime (years)	27	30	30	25	35	25	40		3
Construction time (years)	1.5	1.5	1.5						1
Space requirement (1000 m^2/MWe)	14.0	14.0	14.0						1
Additional data for non thermal plants									
Capacity factor (%), theoretical	28	32	36	15	35	15	40	A,B	6,7
Capacity factor (%), incl. outages	27	31	35						3
Ramping configurations									
Ramping (% per minute)	-	-	-					E	
Minimum load (% of full load)	-	-	-					E	
Warm start-up time (hours)	-	-	-						
Cold start-up time (hours)	-	-	-						
Environment									
PM 2.5 (gram per Nm^3)	0	0	0						
SO_2 (degree of desulphuring, %)	0	0	0						
NO_X (g per GJ fuel)	0	0	0						
CH_4 (g per GJ fuel)	0	0	0						
N_2O (g per GJ fuel)	0	0	0						
Financial data									
Nominal investment (M$/MWe)	1.65	1.20	0.95	1.20	2.35	0.60	1.85	A,D,F	1,5,8
- of which equipment	65%	65%	65%					C	2,3
- of which installation	35%	35%	35%					C	2,3
Fixed O&M ($/MWe/year)	40,000	36,000	30,000	30,000	70,000	25,000	60,000	G	4,5,9
Variable O&M ($/MWh)	0	0	0						4,5
Start-up costs ($/MWe/start-up)	0	0	0						

References:

1 MEMR Focus Group Discussions with various stakeholders for the purposes of updating the Technology Catalogue in 2023
2 IRENA, Renewable Power Generation Costs in 2022, 2023
3 Danish Energy Agency, 2012/2016.Technology Data on Energy Plants - Generation of Electricity and District Heating, Energy Storage and Energy Carrier Generation and Conversion
4 IEA Wind Task 26, 2015, "Wind Technology, Cost, and Performance Trends in Denmark, Germany, Ireland, Norway, the EU, and the USA: 2007–2012".
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Notes:

A The onshore turbine assumed in this technology catalog is a class III turbine, as the onshore wind speeds in Indonesia are very low.
B The capacity factor provided represents the expected performance at the best onshore wind locations in Indonesia (where average wind speeds are above 6 m/s), which are found almost exclusicly on Jawa. However, the majority of Indonesia as very low wind speeds, where capacity factor below 20% should be expected
C Equipment: Cost of turbines including transportation. Installation: Electricical infrastructure of turbine, civil works, grid connection, planning and management. The split of cost may vary considerably from project to project.
D The CapEx decrease comes from the NREL ATB's moderate scenario
E With sufficient wind resource available (wind speed higher than 4-6 m/s and lower than 25-30 m/s) wind turbines can always provide down regulation, and in many cases also up regulation, provided the turbine is running in power-curtailed mode (i.e. with an output which is deliberately set below the possible power based on the available wind).
F For 2020, uncertainty ranges are based on cost spans of various sources. For 2050, we combine the base uncertainity in 2020 with an additional uncertainty span based on learning rates variying between 10-15% and capacity deployment from Stated Policies and Sustainable Development scenarios separately.
G Fixed O&M includes cost of land

Technology

Technology	Wind power - Small onshore wind turbines < 1 MW								
	2023	2030	2050	Uncertainty (2023)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	0.9	0.9	1.0						6
Generating capacity for total power plant (MWe)	13	18	19						5
Electricity efficiency, net (%), name plate	100	100	100					A	
Electricity efficiency, net (%), annual average	100	100	100						
Forced outage (%)	0	0	0						
Planned outage (weeks per year)	0.16	0.2	0.2	0	0	0	0		3
Technical lifetime (years)	27	30	30	25	35	25	40		3
Construction time (years)	1	1	1						5,6
Space requirement (1000 m^2/MWe)	14.0	14.0	14.0						1,6
Additional data for non thermal plants									
Capacity factor (%), theoretical	28	32	36	15	35	15	40	B	2
Capacity factor (%), incl. outages	27	31	35						
Ramping configurations									
Ramping (% per minute)	-	-	-					F	
Minimum load (% of full load)	-	-	-					F	
Warm start-up time (hours)	-	-	-						
Cold start-up time (hours)	-	-	-						
Environment									
PM 2.5 (gram per Nm^3)	0	0	0						
SO_2 (degree of desulphuring, %)	0	0	0						
NO_X (g per GJ fuel)	0	0	0						
CH_4 (g per GJ fuel)	0	0	0						
N_2O (g per GJ fuel)	0	0	0						
Financial data									
Nominal investment (M$/MWe)	4.20	3.57	3.02	3.2	5.3	2.3	3.8	D,E	5, 6
- of which equipment	55%	55%	55%					C	
- of which installation	45%	45%	45%					C	
Fixed O&M ($/MWe/year)	83,448	70,900	60,100	62,600	104,300	75,100	45,100	E	4
Variable O&M ($/MWh)	0	0	0						4
Start-up costs ($/MWe/start-up)	0	0	0						

References:

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5 Case: Faroe Islands, Húsahagi 2014

6 Case: Kenya, Lake Turkana, 2014-2017

Notes:

A The efficiency is defined as 100%. The improvement in technology development is captured in capacity factor, investment cost and space requirement.

B The capacity factor provided represent an average of good locations in Indonesia, see presentation in catalogue text. As mentioned in the description, generelly speaking, the wind resource in Indonesia is scarce.

C Equipment: Cost of turbines including transportation. Installation: Electricical infrastructure of turbine, civil works, grid connection, planning and management. The split of cost may vary considerably from project to project.

D The IEA expects approximately a doubling of the accumulated wind power capacity between 2020 and 2030 and 4-5 times more by 2050 compared to 2020. Assuming a learning of 12.5 % per annum this yields a cost reduction of approx. 13 % by 2030 and approx. 25 % by 2050.

E Uncertainty (Upper/Lower) is estimated as +/- 25%.

F With sufficient wind resource available (wind speed higher than 4-6 m/s and lower than 25-30 m/s) wind turbines can always provide down regulation, and in many cases also up regulation, provided the turbine is running in power-curtailed mode (i.e. with an output which is deliberately set below the possible power based on the available wind).

Technology

Technology	Wind power - Offshore								
	2023	2030	2050	Uncertainty (2023)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	8	16	20						3
Generating capacity for total power plant (MWe)	240	480	600						
Rotor Diameter (m)	171	248	296						
Hub Height (m)	107	146	170						
Specific Power (W/m2)	350	330	290						
Forced outage (%)	0.04	0.0	0.0						3
Planned outage (weeks per year)	0.16	0.16	0.16						3
Technical lifetime (years)	27	30	30	20	35	20	35		3
Construction time (years)	3.0	2.5	2.5	1.5	4	1.5	4		3
Space requirement (1000 m^2/MWe)	185	185	185	168	204	168	204		3
Additional data for non thermal plants									
Capacity factor (%), theoretical	0	0	0					B	2,6,7
Capacity factor (%), incl. outages	0	0	0						
Ramping configurations									
Ramping (% per minute)	-	-	-					F	
Minimum load (% of full load)	-	-	-					F	
Warm start-up time (hours)	-	-	-						
Cold start-up time (hours)	-	-	-						
Environment									
PM 2.5 (gram per Nm^3)	0	0	0						
SO_2 (degree of desulphuring, %)	0	0	0						
NO_X (g per GJ fuel)	0	0	0						
CH_4 (g per GJ fuel)	0	0	0						
N_2O (g per GJ fuel)	0	0	0						
Financial data									
Nominal investment (M$/MWe)	4.10	3.57	2.87	3.50	4.50	1.55	3.20	D,G	3,5
- of which equipment	45%	45%	45%					C	3
- of which installation	55%	55%	55%					C	3
Fixed O&M ($/MWe/year)	118,768	99,791	81,290	109,000	123,000	61,000	95,000		5
Variable O&M ($/MWh)	5.50	4.80	3.90	3.40	5.80	2.70	4.30		4
Start-up costs ($/MWe/start-up)	0	0	0						

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4 IEA Wind Task 26, 2015, "Wind Technology, Cost, and Performance Trends in Denmark, Germany, Ireland, Norway, the EU, and the USA: 2007–2012".
5 NREL's Annual Technology Baseline ATB 2023
6 Renewables Ninja
7 Global Wind Atlas

Notes:

A The efficiency is defined as 100%. The improvement in technology development is captured in capacity factor, investment cost and space requirement.
B The capacity factor provided represent an average of the absolute best fixed-bottom offshore wind locations in Indonesia (specifically south of Papua)
C Equipment: Cost of turbines including transportation. Installation: Electricical infrastructure of turbine, civil works, grid connection, planning and management. The split of cost may vary considerably from project to project.
D The IEA expects approximately a doubling of the accumulated wind power capacity between 2020 and 2030 and 4-5 times more by 2050 compared to 2020. Assuming a learning of 12.5 % per annum this yields a cost reduction of approx. 13 % by 2030 and approx. 30 % by 2050.
E Uncertainty (Upper/Lower) is estimated as +/- 25%.
F With sufficient wind resource available (wind speed higher than 4-6 m/s and lower than 25-30 m/s) wind turbines can always provide down regulation, and in many cases also up regulation, provided the turbine is running in power-curtailed mode (i.e. with an output which is deliberately set below the possible power based on the available wind).
G For 2023, uncertainty ranges are based on cost spans of various sources. For 2050, we combine the base uncertainity in 2020 with an additional uncertainty span based on learning rates variying between 10-15% and capacity deployment from Stated Policies and Sustainable Development scenarios separately.

Technology

Technology	Wind power - Floating offshore								
	2023	**2030**	**2050**	**Uncertainty (2023)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data				**Lower**	**Upper**	**Lower**	**Upper**		
Generating capacity for one unit (MWe)	7	16	20						1,2,5
Generating capacity for total wind farm (MWe)	35	500	1000						1,5
Electricity efficiency, net (%), name plate									
Electricity efficiency, net (%), annual average									
Forced outage (%)	6	4	4						3
Planned outage (%)	0.6	0.6	0.6						3
Technical lifetime (years)	20	25	30						4
Construction time (years)	3.0	2.5	2.5						4
Space requirement (1000 m^2/MWe)	185	185	185						4
Additional data for non thermal plants									
Capacity factor (%), theoretical	36%	38%	40%	-	-	-	-	D	
Capacity factor (%), incl. outages	34%	36%	38%	-	-	-	-		
Ramping configurations									
Ramping (% per minute)	-	-	-	-	-	-	-	B	
Minimum load (% of full load)	-	-	-	-	-	-	-	B	
Warm start-up time (hours)	-	-	-	-	-	-	-		
Cold start-up time (hours)	-	-	-	-	-	-	-		
Environment									
PM 2.5 (gram per Nm^3)									
SO_2 (degree of desulphuring, %)									
NO_X (g per GJ fuel)									
Financial data									
Nominal investment (M$/MWe)	5.50	4.00	3.00	4.0	7.0	2.0	4.0		3,4,5
- of which equipment (%)	80	65	60					A	
- of which installation (%)	20	35	40					A	
Fixed O&M ($/MWe/year)	155,000	125,000	65,000	140,000	180,000	52,000	81,000	C	4,5
Variable O&M ($/MWh)	-	-	-					C	4,5
Start-up costs ($/MWe/start-up)	0	0	0						
Technology specific data									
Rotor diameter (m)	150	200	250						1
Hub height (m)	100	170	180						1
Specific power (W/m2)	396	509	407						1
Availability (%)	94%	96%	96%						3

References:

1 Global Wind Energy Council, 2020, "Global Offshore Wind Report 2020"
2 BVG Associates, 2020, "Offshore wind roadmap for Vietnam"
3 Borg M. et al., *Qualification of innovative floating substructures for 10MW wind turbines and water depths greater than 50m*, 2019
4 World Bank, *Offshore wind roadmap for Vietnam: Preliminary Findings,* 2020.
5 AEGIR, *Vietnam site LCOE screening*, 2020.
6 M. Aquilina, 2014, "Cost Modelling of Floating Wind Farms with Upscaled Rotors in Maltese Waters"

Notes:

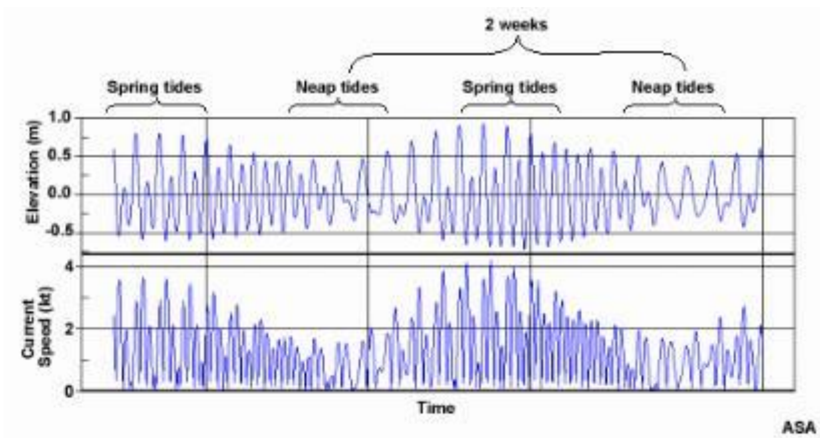
A Equipment: Cost of turbines including transportation. Installation: Electricical infrastructure of turbine, civil works, grid connection, planning and management. The split of cost may vary considerably from project to project.
B With sufficient wind resource available (wind speed higher than 4-6 m/s and lower than 25-30 m/s) wind turbines can always provide down regulation, and in many cases also up regulation, provided the turbine is running in power-curtailed mode (i.e. with an output which is deliberately set below the possible power based on the available wind).
C Operation and maintenance is entirely allotted to the fixed part.
D In Indonesia, floating offshore sites - further from shore - have only marginally better average wind speeds as fixed-bottom sites, which are already quite low relative to globally advantageous locations.

5. Tidal Power

Brief technology description

Tidal energy has been harnessed for various purposes since the 19th century. The oldest tidal power plant has been in operation since 1966. Despite these facts, as of 2019, the total installed capacity of marine energy in the world is a little over 500 MW. However, in the last decade there has been a renewed interest in harnessing tidal power, with marine energy sources (which includes tidal, wave and other ocean energy technologies) estimated to be 60 GW of installed electrical capacity by 2040 (ref. 1).

Tides are the result of the gravitational force from the sun and moon, combined with the rotation of the earth. The tidal cycles may be semidiurnal (i.e. two high tides and two low tides each day), or diurnal (i.e. one tidal cycle per day). Tidal energy is a variable yet highly predictable source of energy. Tides in most sites are semidiurnal, with a cycle lasting approximately twelve and a half hours. Tidal cycles also vary over a 14-day spring and neap cycle. During the spring tide tidal elevation is at a maximum and this occurs due to the full or new moon being in line with the Sun and Earth. When the moon is at first or third quarter, the Sun and Moon are at 90° to each other when viewed from the Earth, thus the solar tidal force partially cancels the lunar tidal force. At this point the tidal current is at a minimum, causing the neap tide. There is a seven-day interval between spring and neap tides (ref. 2).



Time series representation of spring and neap tide along with correlation with tidal current speed variation. (ref. 3)

An important parameter with regards to tidal resources is the tidal current, which is the movement of water and flow of water currents associated with the rise and fall of tides. The tidal current resource follows a sinusoidal curve with the largest currents generated during the mid-tide. The ebb-tide (when the water level is falling) often has slightly larger currents than the flood-tide (when water level is rising). The figure above shows the correlation between tidal elevation and the speed of tidal currents.

Furthermore, various non-tidal currents can also be exploited for tidal energy. This is especially relevant for the Indonesian perspective, as the Indonesian Throughflow (ITF) plays an important role with regards to water currents. The Indonesian Throughflow (ITF) is an ocean current with importance for global climate since it provides a low-latitude pathway for warm, freshwater to move from the Pacific to the Indian Ocean.

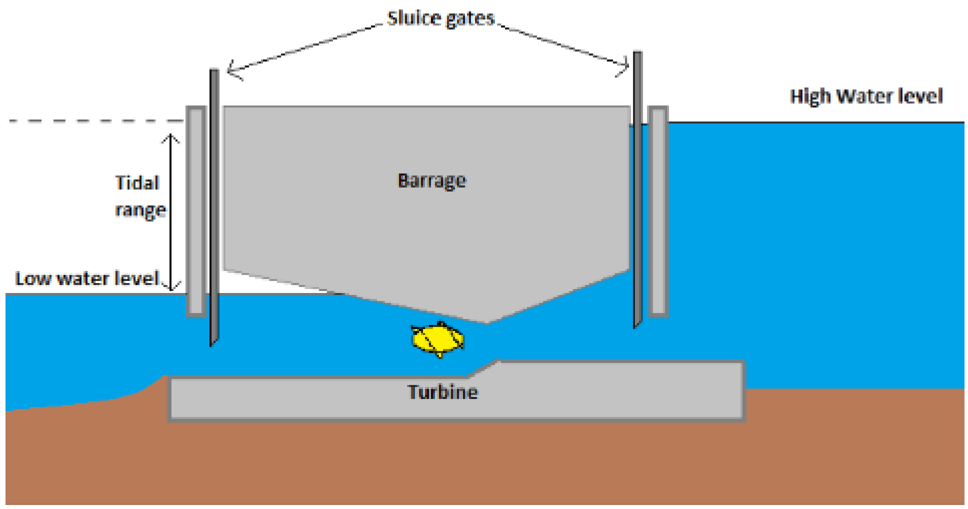
Tidal power plants exploit this movement of water to produce electricity. They are two main types of tidal power plants:

Tidal Impoundment: Broadly speaking this technology is very similar to hydropower plants. It requires the construction of a barrier to impound a large body of water and uses the difference in water levels to rotate the turbine and produce electricity. Tidal impoundment traps/impounds water, which can be used through various generation schemes: ebb generation, flood generation and two-way generation.

Ebb-generation: When the impounded water is at a higher level than that on the open sea or ocean side, the sluice gates (see figure) are opened to let the water flow. The water rotates the turbine while flowing out.

Flood generation: It is the opposite of ebb-generation. Here the flow of water is in the reverse direction, that is, the open sea/ocean side is at a higher level, and the water can flow from this side to the impounded side. However, this scheme is generally less efficient due to the shape of the waterbed, where the depth is lower on the impounded side.

Two-way generation: This is an amalgamation of both ebb and flood generation.



Schematic of tidal impoundment type plant. (ref. 4)

Tidal impoundment technologies are best located in shallow waters with a high tidal elevation or range (difference in height between high and low tide levels) and these ranges increase substantially towards the coast (ref. 2). Tidal impoundment plants can be designed in two ways called tidal barrages and tidal lagoons.

- *Tidal barrage* involves building a dam-like structure across a water body with a high tidal elevation, thereby creating an impoundment on one side of the dam.
- *Tidal lagoons* can be of two types. *Bounded tidal lagoons* are impoundments constructed against the banks of the shallow water areas. *Offshore tidal lagoons* are a more recent development, where a completely artificial offshore impoundment is built on tidal flats in high tidal range areas.

(a) (b) (c)

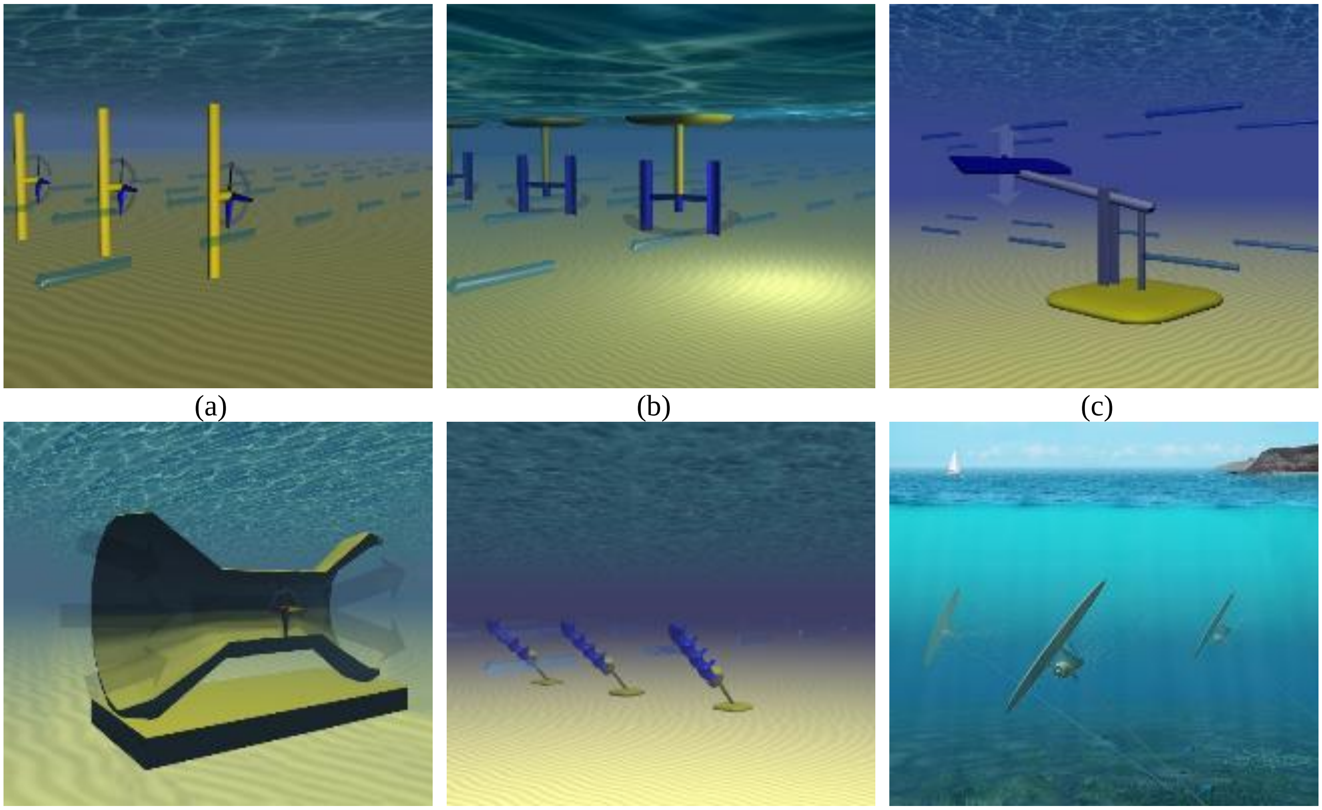
Tidal impoundment types: (a) Tidal barrage (b) Bounded tidal lagoon (c) Offshore tidal lagoon (ref. 2)

Tidal Stream: Utility-scale tidal stream energy conversion devices are a fast-upcoming technology, especially in the UK. While tidal impoundment exploits the energy from difference in water levels, tidal stream uses the kinetic energy from the flow of currents due to varying tides, also known as tidal current. The working principle for tidal stream is similar to wind power plants. Instead of the thrust force from wind, the force from flow of water currents is used to rotate the turbine. The advantage is that, because water is 830 times denser than air, large amounts of power can be produced with relatively small rotor diameters and slow rotation speeds (~10 rpm). However, this implies that, tidal stream turbines must be built much sturdier and marinized, which increases costs. An important factor to consider for tidal stream plants is the strength of the currents generated by the tidal and non-tidal resources, which vary depending on location, the shape of the coastline and depth of water.

The types of turbine technologies for tidal stream plants are (ref. 2, 5):

- *Horizontal axis turbine*: These work fundamentally in the same way as wind turbines. The tidal stream causes the rotors to rotate around the horizontal axis and generate power. The industry term for this technology is tidal turbine generator (TTG).
- *Vertical axis turbine*: Operating principle is similar to horizontal axis turbine. However, the turbine is mounted on a vertical axis. The tidal stream causes the rotors to rotate around the vertical axis and generate power.
- *Oscillating hydrofoil*: A hydrofoil is attached to an oscillating arm. The tidal current flowing either side of a wing results in lift. This motion then drives fluid in a hydraulic system to be converted into electricity.
- *Enclosed Tips (Venturi effect device)*: The tidal flow is directed through a duct, which concentrates the flow and produces a pressure difference. This causes a secondary fluid flow through a turbine. The resultant flow can drive a turbine directly or the induced pressure differential in the system can drive an air-turbine.
- *Archimedes Screw*: The Archimedes Screw is a helical corkscrew-shaped device (a helical surface surrounding a central cylindrical shaft). The device draws power from the tidal stream as the water moves up/through the spiralling turbines.
- *Tidal Kite*: A tidal kite is a device that is tethered to the seabed which carries a turbine below the wing. The kite ‘flies’ in the tidal stream, swooping in a figure-of-eight shape to increase the speed of the water flowing through the turbine to generate electrical power.

Most horizontal and vertical axis turbine use blades that are connected to a central rotor shaft, which through a gearbox, is connected to a generator shaft. Another type, called open-centre turbines, have a different design with the blades mounted on an inner, open centred shaft, housed in a static tube. As the water flows through the shaft, it rotates, and electricity is generated. The advantage of this design is that it eliminates the need for a gearbox. Devices without a gearbox are called direct-drive generators (ref. 6).



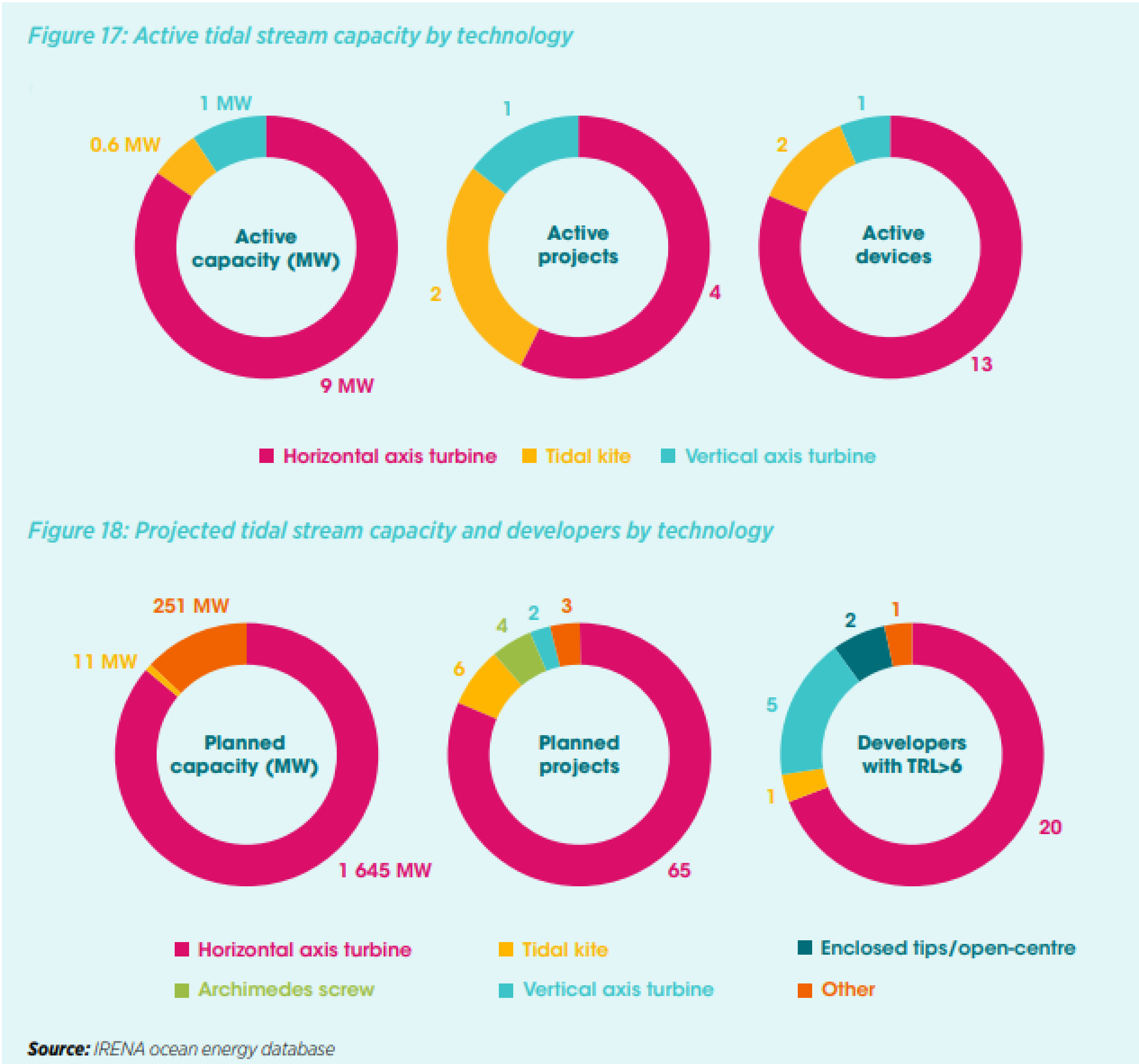
(a) (b) (c)

(d) (e) (f)

Tidal stream turbine types: (a) Horizontal axis turbine (b) Vertical axis turbine (c) Oscillating hydrofoil (d) Enclosed Tips (Venturi effect device) (e) Archimedes screw (f) Tidal kite (ref. 2)

An overview of tidal stream projects shows that nearly two-thirds of all turbine generator assemblies are horizontal axis (ref. 6, 28). Further, most projected multi-device arrays have also settled on horizontal-axis turbines. The relative maturity of this technology reflects its similarity to well-established wind turbines. But it is also favoured due to its easy scalability and its universality, as some developers focus on hydrokinetic turbines that can also be deployed in rivers.

However, 2019 saw more devices other than the horizontal axis technology deployed. The market is therefore taking an interesting turn. Although the non-horizontal-axis turbines are still much smaller in scale and number, the race towards market convergence is not yet finished, and there may soon be larger competition (ref. 28). This can be further seen from the active and projected tidal stream projects data as illustrated in the following figure:

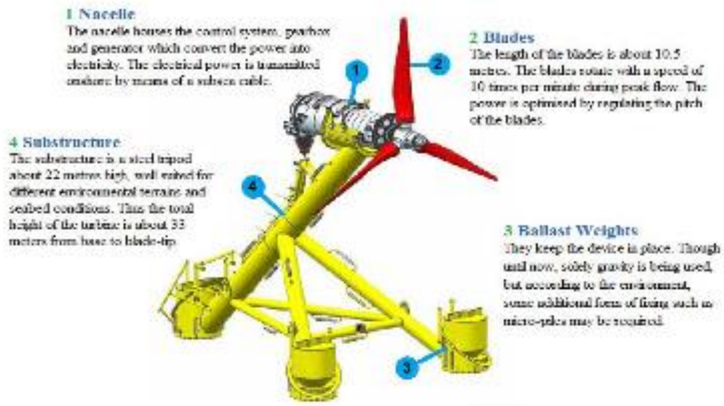


Active and project tidal stream capacity and technology (ref. 28)

A second classification of devices can therefore be based on the depth of the water column and type of foundation (ref. 7).

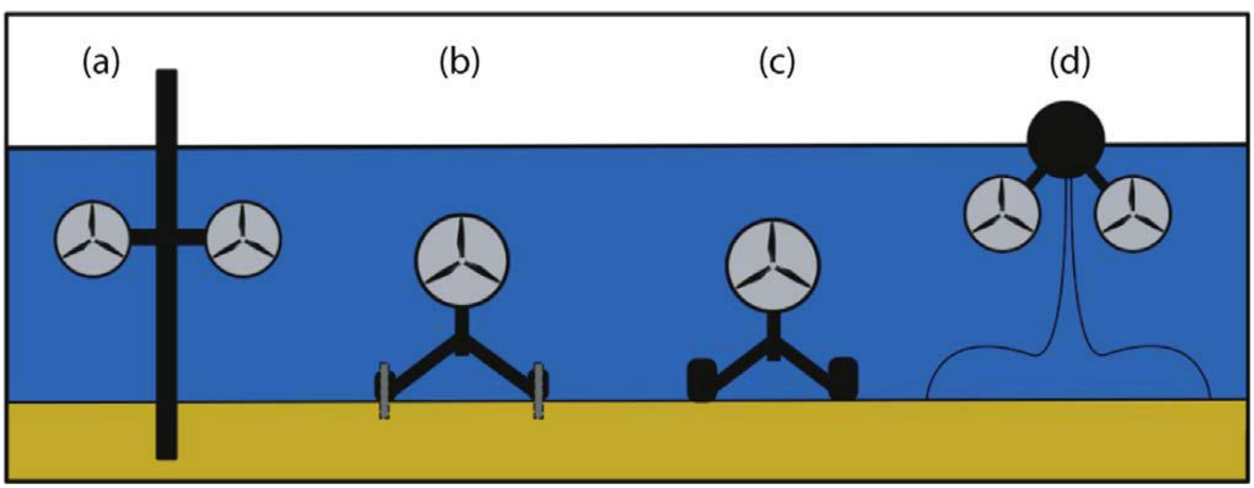
- *First generation*: These consist of devices fastened to the sea floor. They generally operate at depths of up to 40m. The following options with which to fix the turbine to the sea floor exist:
  Monopile: A tubular steel tower or turbine support structure (TSS) is embedded on the seabed and the turbine is mounted on this structure. The use of this design is limited to a water depth of up to 30m (can be up to 100-meter sea water (msw)).
  Piloted: This refers to 'piled' foundations. The foundation is positioned on the seabed, then steel piles are driven through pile-guide openings in the TSS. The piles may be cemented in situ, depending on the type of seabed soils/bedrock.

Gravity: The TSS supports the turbine and secured on the sea floor by means of a substantial mass – e.g., separate 200 tonne ballast weights at each extremity of the TSS.



Early gravity-based substructure design (ref. 8)

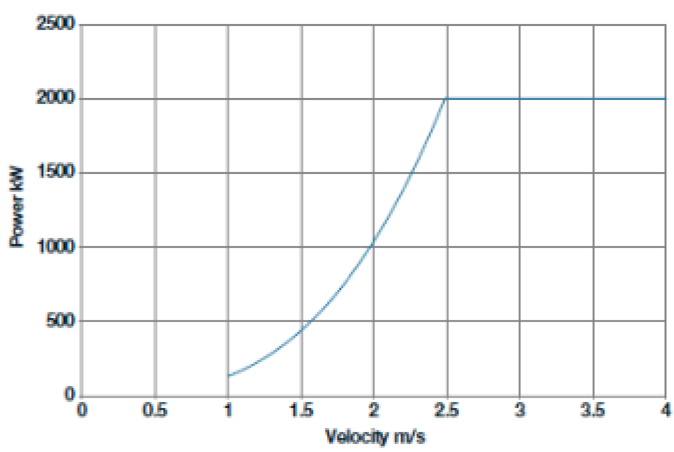
- *Second generation*: This device can float and can be anchored to the seabed via mooring lines or anchoring lines. This kind of floating devices interacts with shallow, near-surface currents. Other devices operate fully submerged with mooring lines and they may be a good proposal for harnessing energy from great depths because they can be installed at the desired depth using buoys and wires. However, these devices have many challenges to overcome like: how to deal with multiple device moorings; the associated long-term safety and maintenance of such deep-water moorings for arrays of floating or semi-submersed turbines. Also, surface-positioned devices are potential shipping hazards; are limited to the depth that the TTG device can be positioned.
- *Third generation*: These include devices that can harness energy from small velocity streams. However, these are still under development and have not been discussed much in literature.



Foundation types: First generation devices (a) Monopile; (b) Piloted; (c) Gravity (d) Pile Foundation. (ref. 7)

Foundation types: Second generation devices - Mooring system based on wires and buoys. (ref. 7)

As mentioned before, the main parameters to consider when estimating resource potential for tidal stream plants is the velocity of the water current. As most turbines are the horizontal and vertical axis design, the discussion here is more relevant for these. Most turbines have a minimum cut-in flow speed of 0.5 to 1.0 m/s with an ideal/operational speed between 1.5 and 3.5 m/s and cut-off speed between 4 and 5 m/s. Based on these values, the power curve for tidal stream turbines would appear to have a shape similar to that of wind turbines. This is further represented by the sample power curve for a theoretical 2 MW turbine shown in the figure.

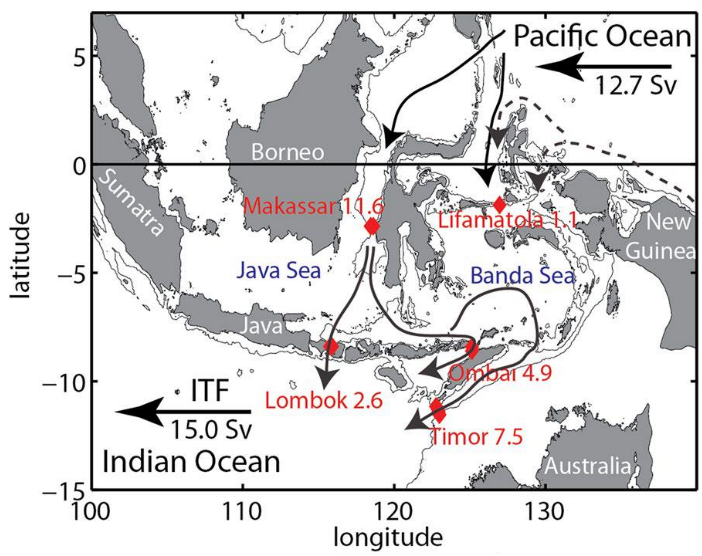


Sample power curve for tidal stream turbine. (ref. 9).

Globally most of the tidal projects so far are around the UK, France, Canada, USA, South Korea and China. However, in recent years there has been increasing interest for tidal power in Indonesia, resulting in various studies to evaluate the tidal power potential. One study found that the tidal currents in narrow straits were relatively high around archipelagos such as the Maluku Islands and Nusa Tenggara Islands. The Lombok Strait exhibited the maximum tidal current velocity of 4 m/s (ref. 10). Another study investigating potential for tidal stream energy in Indonesia assesses ten candidate sites for tidal energy extraction based on field measurements (ref. 11). These are represented in the figure below.

Potential sites for tidal energy generation assessed in Indonesia (ref. 11).

As previously mentioned, the ITF plays a key role in ocean current resources for Indonesia. The location and topography of the channels that make up the ITF are shown in the figure. In the Lombok Strait currents vary between 0.286 m/s eastward to 0.67 m/s westward and average 0.25 m/s westward (ref. 13).



Transport of the currents contributing to the Indonesian Throughflow via different passages. Numbers next to current arrows indicate transport in Sverdrups (Sv) (ref. 14)

While further research and investigation is needed to map the full potential of tidal energy in Indonesia, in general it is known that areas with higher tidal elevation and current velocity are ideal for tidal projects. Other factors that must be considered are type of coastline, available seabed area and sub-soil conditions, depth of water column, potential effect from shipping routes and tourism, impact on marine ecosystems and grid connection proximity.

There have been a few attempts at tidal stream developments, however, only one project has received govt. and PLN approval. This is the Nautilus project.

Input

Depending on the type of plant, the primary input can be from change in tidal elevation or movement of water due to tidal currents. From the Indonesian perspective, the available resources pre-dominantly include daily tidal and 24/7 non-tidal, unidirectional Indonesian Throughflow (ITF) flows.

Output

Electricity.

Typical capacities

Globally, large-scale installed capacity so far, has been of the tidal impoundment type. Plant sizes can vary from less than 10 MW to the larger operational power plants like La Rance Tidal Power Station and Sihwa Lake Tidal Power Station being over 200 MW. Some of the future projects proposed around the world are could be expected to be of much larger sizes going into GW (ref. 15). Therefore, the typical capacity of tidal impoundment type plant varies a lot depending upon area available and tidal resource.

With the exception of proven operating turbines on sites such as MeyGen (Atlantis) since 2016, and Bluemull Sound (Nova Innovations) since April 2014, other OEMs tidal stream devices are still in the early stages of development with most projects being set up for demonstration or pilots. Therefore, typical capacities vary from less than 1 MW to over 100 MW. The MeyGen tidal stream project in the Pentland Firth off the north coast of Scotland, being installed in phases, is expected to be one of the largest with a govt-approved capacity of 398 MW.

Ramping configurations

The operation and control of tidal systems is dependent on the type of turbines and generators used, however there are various strategies that have been explored and successfully used by existing sites. In general, the control systems operate dynamically and are designed to achieve maximum power output following the power curve by adjusting the rotational speed based on the tidal resource. The control of the turbine in a tidal array seeks to optimise operation and power output by applying individual turbine spacing in the water column with due consideration to array orientation within the tidal cycle. The advantage with tidal stream configuration is that the resource is more predictable than wind, allowing for predictive control strategies and therefore better optimization of the output. However, control of tidal stream turbines also needs to account for the harsh operational conditions due to high turbulence events. This is to avoid damage of the equipment. For tidal impoundment, similar to hydropower, the turbine can be ramped rapidly across a wide range. Moreover, the control of sluice gates allows for a better optimisation of power output.

Advantages/disadvantages

Advantages:

- Clean energy, with no emission during generation.
- Higher energy density compared to wind. As water is 830 times denser than air, it allows for a higher energy conversion from a smaller area, despite a narrower speed range. This also allows for smaller rotor design, allowing for reduction in equipment and operation cost.
- Tidal parameters like daily tides, elevation and current velocity are more predictable than other variable renewable energy sources. Moreover, the flow rates are sequential, making tidal better than wind and wave for improving the continuity of energy supply.
- Potentially longer lifetime as compared to solar and wind.

Disadvantages:

- Technology is in its nascent stage, so commercial viability needs to be evaluated.
- High initial investment costs.
- Hard to regulate with respect to energy demand.
- Environmental impact depending on location.

Environment

While the power generation from tidal plants is emission free, the installation of such plants has various external impacts which if not managed properly, can be a hurdle for these projects across the globe. Some of these impacts include:

- Physical changes to the water resource and surrounding coastlines. Increase in water levels and flooding in some locations, while reduced levels of water in other locations is possible due to tidal impoundment projects are possible.
- The potential change in soil quality around projects can have an impact on the ecology of the area.
- The change in tidal elevation and current after the installation of tidal projects can influence the well-being of biodiversity in the area.
- There is a potential impact on marine industries and other human activities that rely on the water bodies like fisheries, agriculture, tourism, and shipping routes.

Predicted environmental impact like flooding in nearby areas and impact on biodiversity in the area have led to the Severn Barrage project in the UK being put on hold for over a decade despite high tidal energy potential. Similarly, the Kislaya Guba tidal power plant in Russia led to diminution of tides, diminution of sea swells, reduction in the flow of fresh water from the partitioned water area to the sea, and the mechanical effect of the turbine on plankton and fish (ref. 16).

With experience and better environmental assessments, future projects could avoid at least some of these pitfalls. This is relevant with the Indonesian context because issues like changes to biodiversity, marine ecology, industries and shipping routes are relevant for many potential sites like the Riau Strait, Toyopakeh Strait, and Mansuar Strait (ref. 11).

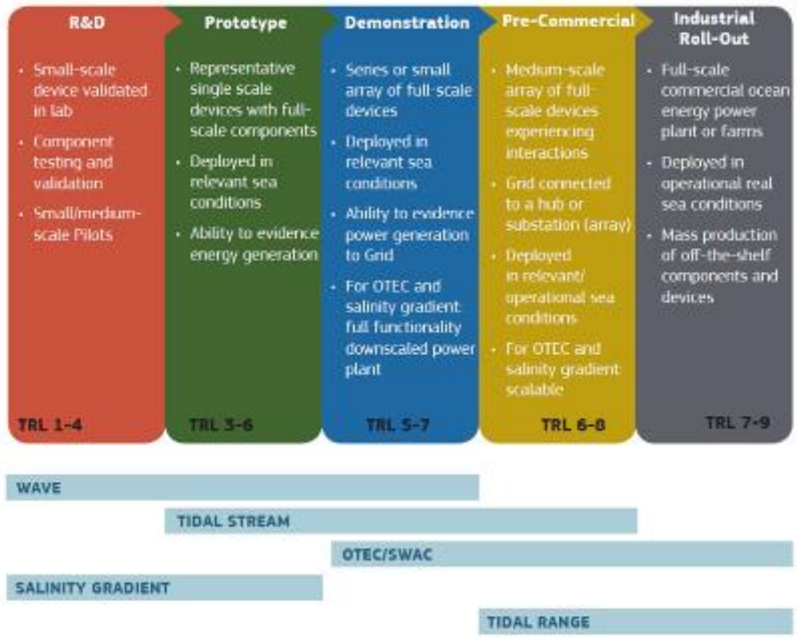
It must also be noted that not all the projects necessarily have negative impacts. In some cases, tidal barrages can improve connectivity and tourism. Tidal stream projects can in some cases also decrease turbidity, or sediment in the water, allowing sunlight to penetrate down and trigger phytoplankton blooms which can have the effect of boosting the food chain positively.

Employment

For Europe it is estimated that a target of 100 GW ocean energy (which includes tidal energy) would lead to 400,000 jobs by 2050. This could imply that potentially 4000 jobs are created per GW of ocean energy development (ref. 17).

Research and development

While the technology behind turbines being used for tidal power has been around for a long time, there is scope for further development. In this regard, tidal impoundment technology can be categorised as category 3 and tidal stream technology is category 2. A well-recognised framework to assess the technology development with ocean energy is the Technology Readiness Levels (TRL). The European Marine Energy Centre (EMEC) is the only grid-connected test facility in the world accredited to issue TRL certification. As seen below, tidal range (impoundment) is considered at a TRL 7-9 level while tidal stream is still at precommercial stage.



Technology Rediness Levels for ocean energy technologies in terms of development stages (ref. 17)

Turbine: To enable turbine blades to withstand strong tidal forces, better design options need to be explored. Avoiding fatigue failure is an important design consideration for tidal turbine blades. Blades are commonly constructed from composite materials made of a polymer reinforced by carbon or glass fibres. There is scope for improvement in design to increase reliability and improve performance by improvements in blade design and innovative use of materials (ref. 18).

One of the recent developments in turbine design is the direct-drive method which eliminates the need for the gearbox. This technology has been successfully installed in Shetland (UK) for commercial purposes. It claims to reduce the cost by a third.

500 kW direct drive turbine (ref. 19)

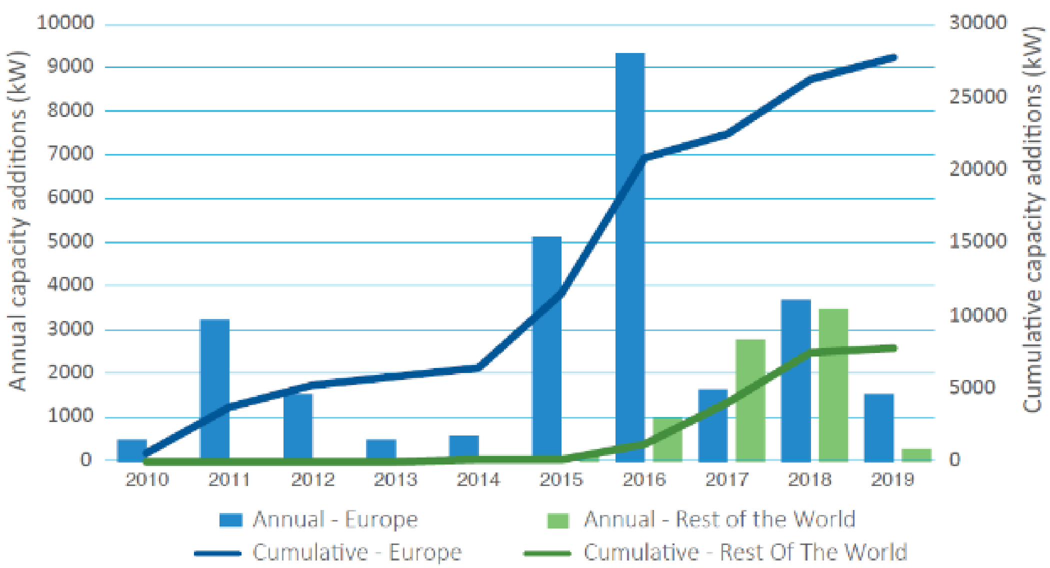
Foundations and mooring: A considerable share of the installation cost is dependent on type of foundation structure. In most cases the type of foundation is either pin-piled or gravity based. Installation of gravity-based foundations is a costly affair as it involves lifting heavy foundation weights into position. The tidal stream sector is moving towards monopile structures as these provide the ability to position the turbine very accurately in the optimum ‘zone’ of the tidal flows. Also, monopiles remove the problem with gravity base structures of uneven seabeds, which is usually the case, and where extensive seabed levelling has been required. Moreover, the demand of steel is almost halved for a mono-pile solution compared to a gravity base. New techniques for pin-piling from remote-operated submarine vehicles are already reducing costs as developers move from prototypes to first arrays (ref. 18).

Installation: In general, ocean energy technologies like tidal have a much higher cost than other renewable technology. A major reason for this is the high cost associated with contracting vessels for installation work. With improved design of components and innovative technologies like mooring systems that can be controlled remotely, the installation costs for some devices types are expected to reduce substantially. Solutions like special subsea drilling techniques (as an alternative to expensive jack-up vessels) and developing installation procedures which allow use of cheaper vessels (ref. 18), are expected to reduce the cost of tidal installations.

Operation and Maintenance: Similar to installation costs, a key factor for high O&M costs for tidal devices is the cost of sea vessels. Moreover, the frequency of device maintenance is also an important reason for higher costs, as it is also linked with vessel usage. Therefore, improvements in deployability or vessel usage of tidal devices is bound to have a positive impact on the cost. An example of technology for easier maintenance is the development of tidal devices with buoyant nacelle (a cover that houses all of the generating components) which can be easily detached and floated to the surface (ref. 18). Like with other technologies, development of predictive maintenance systems that allow for shorter and less frequent maintenance are bound to reduce costs, lesser outage periods and increase plant lifetimes.

Investment cost estimation

Even though tidal energy technology has been around for decades, there has been a very low growth in capacity. As seen in the figure below, the cumulative capacity for tidal stream plants is below 100 MW.



Installed and cumulative tidal stream energy capacity (ref. 20).

Similarly, other than the two largest barrage projects in France and Korea of 240 MW and 254 MW, there has not been significant development for tidal impoundments even though a lot projects have been proposed. Therefore, it is difficult to assess how the cost will develop. The learning rate approach is less applicable here as the technology is still in its early stages of development and more capacity needs to be deployed before learning rate estimates can be calculated. Considering these factors, the cost estimates presented here are based on various ranges from different sources. These are associated with a level of uncertainty because the data is based on relatively older studies. The estimated costs have not been changed from the 2020 version of the Technology Catalogue, but values have been adjusted to 2022 price year.

Investment Cost for Tidal Impoundment:

Investment costs [$MUSD_{2022}$/MW]	**Estimates**	**2023**	**2030**	**2050**
New catalogue (2023		**5.8**	**5.4**	**5.4**
Existing Catalogue (2020)		5.8	5.4	5.4
UK Government (DECC) (ref. 21)	5.62 (3.1 to 7.3)	7.3	5.6	5.6
Literature (ref. 22)	5.4 (3.8 to 6.0)	6.0	5.1	5.1
IRENA (ref. 23)	4.24 (proposed/planned)	4.24		

The recommended values for 2023 are an average of: the higher values and estimated project costs around the world. Under the assumption that with increased deployment in Indonesia the costs will potentially go down, the values for 2030 show a reduction to the central values from the different ranges. However, similar to hydro costs plateauing, it is assumed here that the cost is not expected to reduce a lot more over time. Therefore, it is assumed that they should plateau towards 2050.

Investment Cost for Tidal Stream:

Investment costs [$MUSD_{2019}$/MW]	**Estimates**	**2020**	**2030**	**2050**
New catalogue (2023)		**5.6**	**4.9**	**3.6**
Existing Catalogue (2020)		**5.6**	**4.9**	**3.6**
IEA Report (ref. 24)	4.9 (3.6 to 6.0)	5.94	4.9	3.6
Commercial Developer Suggested Values	3.18 (in UK) 2.12 (in few years)			
Indonesia- Lombok Project (ref. 25)	5.3	5.3		

The recommended cost values here tidal stream in 2023 are an average of: the higher value from IEA report and estimated project cost in Indonesia. For 2030 the central values are considered and for 2050 the lower values are taken. This is done under the assumption that with increased deployment the cost will decrease. However, as the technology is still in early days, there is a higher uncertainty with respect to the cost, as seen by the estimates given by a commercial developer. This uncertainty is accounted for in the range provided in the final data sheet.

It is expected that the learning rate for tidal stream technology in the long term will be between 5% and 10% (ref. 26), which is relatively lower than most other renewable technologies. However, there are some synergies expected between wind, hydro and marine technologies like tidal that can reduce the costs at higher rate. But this can be better predicted once there is higher capacity deployment globally and in Indonesia.

Examples of current projects

The MeyGen tidal stream project in the Pentland Firth off the north coast of Scotland, being installed in phases, is expected to be one of the largest with a govt-approved capacity of 398 MW by 2025. The Phase 1A 6MW demonstration array (comprised four 1.5MW tidal turbines) reached financial close in 2014 and was fully constructed and operational in 2017. Each turbine has a dedicated subsea array cable laid directly on the seabed and brought ashore. The turbines feed into the onshore power conversion unit building at the Ness of Quoys, where the low voltage supply is converted to 33kV for export via the 14.9MW grid connection into the local distribution network. Phase 1A incorporates two different turbine technologies (Atlantis Resources AR1500 and Andritz Hydro Hammerfest AH1000 MK1), with environmental monitoring equipment installed that will assess the interaction between the tidal turbines and the marine environment, including marine mammals. Phase 1b (80MW) is scheduled for 2021/2 (ref. 29).

The Nautilus tidal-stream project will be one of the tidal stream projects in Indonesia located in the Lombok Strait. The total cost of the commercial array has been estimated at USD 750 million. Since 2015, risk assessment; feasibility study and other reports for the project have been delivered. Agreements with the country's state-owned electrical utility company PT. Perusahaan Listrik Negara (PLN) for exclusive tidal energy site developments have been reached. For the project UK based SBS International is working with OEM partner, SIMEC Atlantis Energy to develop the 150 MW tidal turbine generator array using AR2000 turbines. The project plans to build out site capacity in three stages; stage 1: 10 MW by 2022, stage 2: 70 MW and stage 3: 70 MW by 2024 (ref. 25, 27).

PLT arus laut (ref 30)

Nova Innovation Ltd., a Scottish business, is researching the possibilities for electrical energy from the Gonzalu Strait's marine currents. The company tested the current between Adonara Island and Flores Island in East Nusa Tenggara Province. Nova Innovation is a world-class tidal energy company that designs, builds, and operates turbines that generate electricity. Nova Innovation from Scotland, and perhaps this year there are plans for a small ocean current generator, perhaps 100 or 200 kilowatts, for testing.

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Datasheets

The following pages contain the data sheets of the technology. All costs are stated in U.S. dollars (USD), price year 2022.

Technology

Technology	Tidal power - Impoundment Type								
	2023	2030	2050	Uncertainty (2023)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	1	10	25	1	25	1	25	A	3
Generating capacity for total power plant (MWe)	30	100	150	10	300	10	300	B	3
Electricity efficiency, net (%), name plate	90	90	90	85	95	85	95	F	5
Electricity efficiency, net (%), annual average	90	90	90	85	95	85	95	F	5
Forced outage (%)	4	4	4	2	6	2	6		
Planned outage (weeks per year)									
Technical lifetime (years)	40	40	50	30	120	30	120	C	2
Construction time (years)	5	5	4	4	6	4	6		3,5
Space requirement (1000 m^2/MWe)	0.2	0.2	0.2	0.1	0.3	0.1	0.3	D	
Additional data for non thermal plants									
Capacity factor (%), theoretical	35	35	40	35	40	35	40	E	
Capacity factor (%), incl. outages									
Ramping configurations									
Ramping (% per minute)	50	50	50	30	100	30	100	G	
Minimum load (% of full load)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	G	
Warm start-up time (hours)	0.1	0.1	0.1	0.0	0.3	0.0	0.3	G	
Cold start-up time (hours)	0.1	0.1	0.1	0.0	0.3	0.0	0.3	G	
Environment									
PM 2.5 (gram per Nm^3)	0	0	0						
SO_2 (degree of desulphuring, %)	0	0	0						
NO_X (g per GJ fuel)	0	0	0						
CH_4 (g per GJ fuel)	0	0	0						
N_2O (g per GJ fuel)	0	0	0						
Financial data									
Nominal investment (M$/MWe)	5.80	5.40	5.40	3.10	8.00	3.10	8.00	E	1,2,4
- of which equipment									
- of which installation									
Fixed O&M ($/MWe/year)	75,048	66,250	37,842	24,804	76,320	24,804	76,320	E	1,2,3,4
Variable O&M ($/MWh)									
Start-up costs ($/MWe/start-up)									

References:
1 DECC GOV.UK, "The UK 2050 Calculator: Tidal Range Cost Data," 2011.
2 Ernst & Young, "Cost of and financial support for wave, tidal stream and tidal range generation in the UK," 2010
3 IRENA, "Tidal Energy Technology Brief," 2014
4 Pacific Northwest National Laboratory (PNNL), Tethys
5 Tatiana Montllonch Araquistain, Tidal Power: Economic and Technological assessment.

Notes:
A Based on various projects and company datasheets. The turbine size can vary from project to project based on requirement. The Sihwa Lake project in Korea has 25.4 MW turbines.
B The capacity is strongly dependent on resources available and shape of coastline. Although a lot of proposed plants are much larger in size, with some being over 2 GW as well, the capacity shown here is based on deployment of plants so far.
C Actual operational life can be upto 120 years. However, lifetime is taken as 40 years, since there can be significant re-fitting costs after 40 years and discounted cash flows are insignificant after 40 years.
D Based on information of proposed plants.
E The projections here are assuming that with increased deployment and improved technology the values will improve within the range estimated.
F Bulb type turbines are commonly used for tidal impoundment plants. The value here is estimated based on efficiencies of bulb type water turbines.
G Considered as similar to Hydro

Technology

Technology	Tidal power - Stream Type								
	2023	2030	2050	Uncertainty (2023)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	1	2	2	0	6	1	6	A	3,5
Generating capacity for total power plant (MWe)	10	150	150	1	400	1	400	A	3,5
Electricity efficiency, net (%), name plate	90	92	95	87	97	87	97	B	2,3,5
Electricity efficiency, net (%), annual average	90	92	95	87	97	87	97	B	2,3,5
Forced outage (%)	4	4	4	2	6	2	6		2
Planned outage (weeks per year)									
Technical lifetime (years)	25	25	30	20	30	20	30	B	
Construction time (years)	3	2	2					C	
Space requirement (1000 m^2/MWe)									
Additional data for non thermal plants									
Capacity factor (%), theoretical	33	35	37	33	40	35	40	B	1,2,4
Capacity factor (%), incl. outages	33	35	37	33	40	35	40	B	1,2,4
Ramping configurations									
Ramping (% per minute)	-	-	-						
Minimum load (% of full load)	-	-	-						
Warm start-up time (hours)	-	-	-						
Cold start-up time (hours)	-	-	-						
Environment									
PM 2.5 (gram per Nm^3)	0	0	0						
SO_2 (degree of desulphuring, %)	0	0	0						
NO_X (g per GJ fuel)	0	0	0						
CH_4 (g per GJ fuel)	0	0	0						
N_2O (g per GJ fuel)	0	0	0						
Financial data									
Nominal investment (M$/MWe)	5.60	4.90	3.60	3.20	7.50	2.10	7.50	B	1,2,3
- of which equipment	87%	87%	87%	83%	91%	83%	91%		1,2
- of which installation	13%	13%	13%	9%	17%	9%	17%		1,2
Fixed O&M ($/MWe/year)	299,980	243,800	120,840	98,580	436,720	98,580	436,720	B	1,2
Variable O&M ($/MWh)	12.00	9.00	8.00						4
Start-up costs ($/MWe/start-up)									

References:

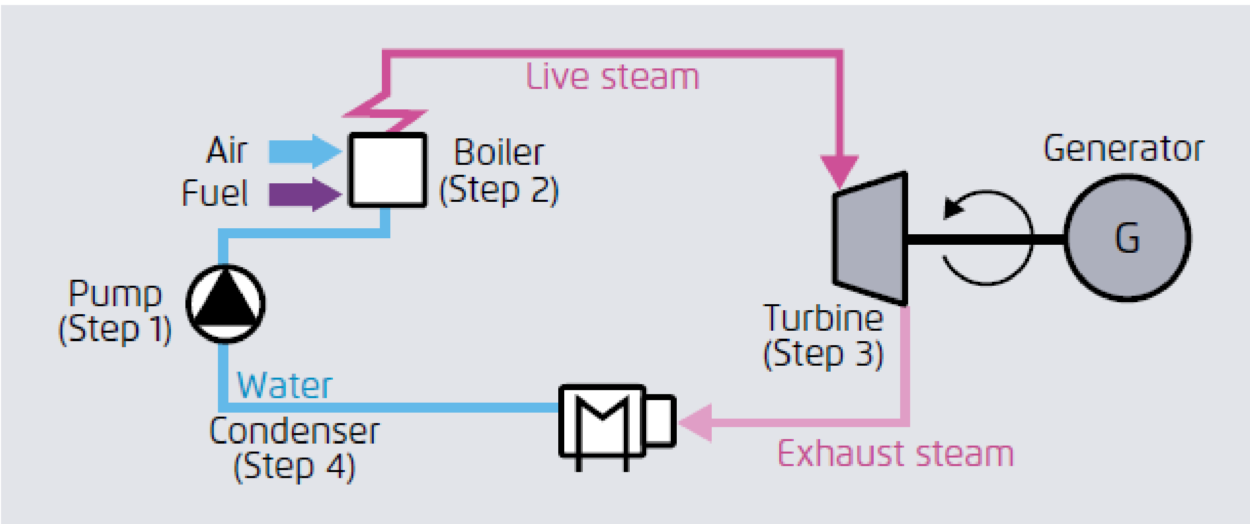
1 Ernst & Young, "Cost of and financial support for wave, tidal stream and tidal range generation in the UK," 2010.
2 Ocean Energy Systems - OES (IEA), "International Levelised Cost of Energy for Ocean Energy Technologies," 2015.
3 SIMEC Atlantis Energy, Projects
4 UK Govt., Electricity Generation Costs 2020 (back calculation from LCOE values)
5 Pacific Northwest National Laboratory (PNNL), Tethys

Notes:

A Projects are in the early stages os turbines and capacities are smaller. Larger projects are expected to be executed in smaller capacity phases.
B The projections here are assuming that with increased deployment and improved technology the values will improve within the range estimated.
C Estimated based on MeyGen tidal stream project

6. Coal Power Plant - Steam Cycle

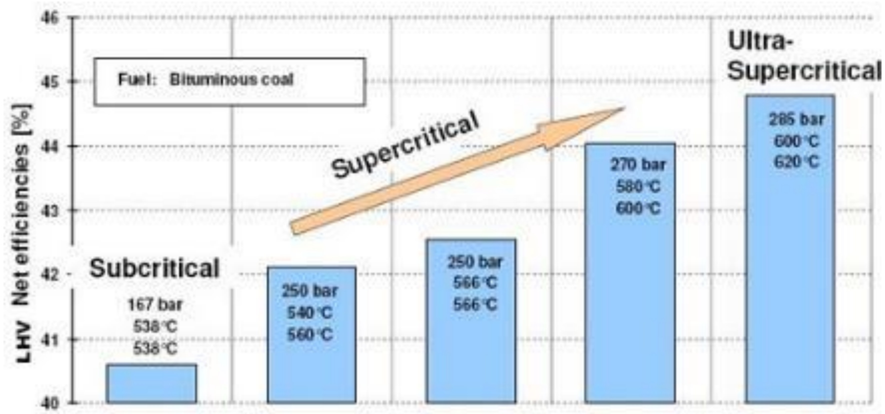
Brief technology description
Coal-fired plants run on a steam-based Rankine cycle. In the first step the operating fluid (water) is compressed to high pressure using a pump. The next step, the boiler heats the compressed fluid to its boiling point converting it to steam, still at a high pressure. In the third step the steam is allowed to expand in the turbine, thus rotating it. This in turn rotates the generator to produce electricity. The final step in the cycle involves the condensation of the steam in the condenser.



Schematic representation of operational flow of steam-based Rankine cycle in coal plants (ref. 2).

We distinguish between three types of coal fired power plants: subcritical, supercritical and ultra-supercritical. The names refer to the state (temperature and pressure) of the steam during the evaporation phase. Besides the technical variations in the plant layout, from an energy modelling perspective the main differences lie in the plant's cost and in its cycle efficiency, as shown in the figure below.

Subcritical is below 200 bars and 540°C. Both supercritical and ultra-supercritical plants operate above the water-steam critical point, which requires pressures of more than 221 bars (by comparison, a subcritical plant will generally operate at a pressure of around 165 bars). Above the water-steam critical point, water will change from liquid to steam without boiling – that is, there is no observed change in state and there is no latent heat requirement. Supercritical designs are employed to improve the overall efficiency of the generator. There is no standard definition for ultra-supercritical versus supercritical. The term 'ultra-supercritical' is used for plants with steam temperatures of approximately 600°C and above (ref. 1).

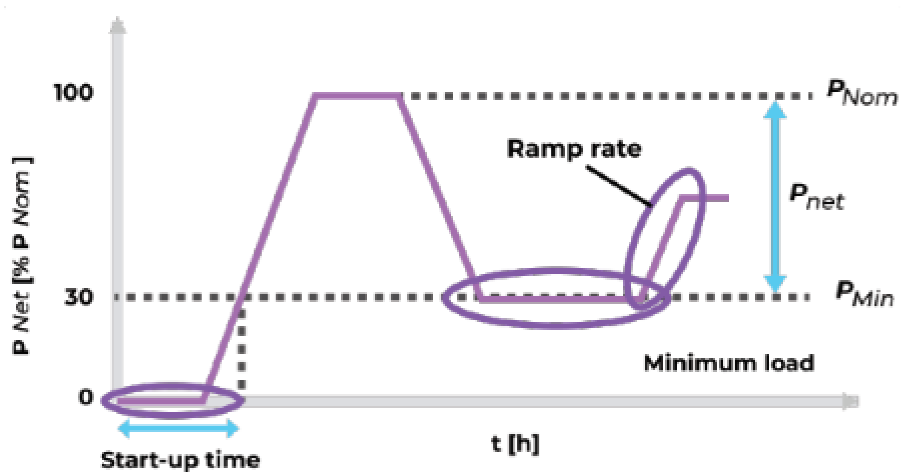


Differences between sub-, super-, and ultra-supercritical plant (ref. 6).

Flexibility of coal power plants

With the increase in variable sources of electricity like solar and wind, coal-fired plants need to be more flexible to balance the power grid. Key parameters related to the flexibility of a thermal plant are:

- **Minimum Load (P_{min})**: Is the minimum or lowest power that can be produced by the plant.
- **Maximum Load (P_{nom})**: It is the nominal capacity of a plant.
- **Start-up time**: It is the time needed for the plant to go from start of operation to the generation of power at minimum load. There are three types of start-up: **hot start-up** is when the plant has been out of operation for less than 8 hours, **warm start-up** is when the plant has not been operational for 8 to 48 hours, and **cold start-up** is when the plant is out of operation for more than 48 hours.
- **Ramp-rate**: It refers to the change in net power produced by the plant per unit time. Normally, the unit for ramp rate is MW/min or as a percentage of the nominal load per minute. Usually there is a ramp up rate for increase in power and ramp down rate for a decrease in power produced.
- **Minimum up and down time**: The up time refers to the minimum time the plant needs to be in an operational state once turned on. The down time refers to the minimum time after shutdown that the plant is out of operation, before it can be turned on again.



Key flexibility parameters of a power plant (ref. 3).

These parameters represent critical operation characteristics of a thermal power plant. Therefore, for a coal plant to be more flexible, it would be ideal to reduce minimum load, reduce the start-up time and increase the ramp rate. In this regard, there are various retrofit solutions that can be added on to existing plants or considered when building new plants. These solutions have been summarised in the table below.

Solutions for increasing the flexibility of coal-fired power plants (ref. 2).

Solutions	Objective	Description	Impact	Limitation
Indirect Firing	Lower minimum load, increased ramp rate and better part load efficiency	Milling is decoupled from load dynamics. Involves setting up a dust bunker between the coal mill and the burner to store pulverized coal. During periods of low load, auxiliary power can be used for coal milling, thereby reducing total power injected into the grid. Plus this reduces the minimum load in high load periods as the required coal is already stored in the bunker and can be used flexibly.	Indirect firing can decrease the minimum stable firing rate. Firing rate and net power are proportional. A reduction of the firing rate therefore leads to a similar reduction of minimum load. Another advantage of reaching a low stable fire is that the need for ignition fuels, such as oil or gas, can be reduced by 95 %.	Fire stability
Switching from two-mill to single-mill operation	Lower minimum load	Switching to a single mill operation results in boiler operation with fewer burning stages. In this operation, heat is released only at the highest burner stage, ensuring operational stability.	Switching to a single mill operation has resulted in reducing minimum load to 12.5% P_{nom} in experiments conducted in hard coal-fired thermal plants at Bexbach and Heilbronn in Germany.	Water-steam circuit
Control system optimization and plant engineering upgrade	Lower minimum load, higher ramp rate, shorter start-up time	Upgrading control systems can improve plant reliability and help operate different components of the plant close to their design limits.	Control system and engineering upgrades resulted in the reduction of minimum load from nearly 67% P_{nom} to 48% P_{nom} at two units in the Weisweiler lignite-fired plant in Germany.	Fire stability/thermal stress
		Software systems that enable dynamic optimization of key components such as boilers can reduce the start-up time and increase ramp rate.	Boiler control system software have been developed that allow plant operators to choose between different start-up options based on market requirements.	
Auxiliary firing for stabilizing fire in boiler	Lower minimum load, higher ramp rate	This involves using auxiliary fuel such as heavy oil or gas to stabilize fire in the boiler. This ensures a lower stable firing rate in the boiler. Auxiliary firing can also be used for rapid increases to the firing rate, thereby enabling a higher ramp rate.	Since fire stability in the boiler usually limits the minimum load, auxiliary firing can support the minimum load reduction. As part of Jänschwalde research project, ignition burners were used for auxiliary firing using dried lignite, which	Fire stability and boiler design

			reduced the minimum load from 36% P_{nom} to 26% P_{nom}.	
“New” turbine start	Shorter start-up time	This option involves starting up the steam turbine as the boiler ramps up by allowing “cold” steam to enter the turbine quickly after shutdown.	The start-up time can be reduced by 15 minutes using this approach.	Turbine design
Thin-walled components/special turbine design	Shorter start-up time, higher ramp rate	Using high-grade steel, thinner-walled components can be built to ensure quicker start-up and higher ramp rates compared to traditional thick-walled components.	Not known.	Mechanical and thermal stresses
Thermal energy storage for feed water preheating	Lower minimum load	Heat from the steam turbine can be absorbed by feed water, thereby reducing net power. Thermal energy stored in the feed water can be discharged to increase net power during periods of high demand.	Using a hot water storage system that can operate for 2–8 hours can reduce minimum load by 5–10%, and during discharge the hot water system can be used to increase net power by 5% without increasing the firing rate.	-

It is important to mention here that, while improved flexibility can allow for better operation of the plant, there are certain drawbacks to frequent plant start-ups and fast load swings that occur under such operation. Flexible operation causes thermal and mechanical fatigue stress on some of the components. When combined with normal plant degradation this can reduce the expected life of some pressure parts. In this regard, the critical parts that need to be given more attention to are the boiler and steam turbine systems (ref. 5).

The improvement in flexibility of plants is dependent on various factors like age of plant, existing technology, type of coal and various thermodynamic properties. Therefore, ideally, the improvement should be calculated on a case-by-case basis. However, various studies and projects have been conducted around the world to measure the improvement in flexibility. The table below provides a summary and comparison of potential improvement in relevant parameters for a hard coal-fired power plant before and after flexibilisation.

Comparison of flexibility parameters before and after flexibilisation initiatives in a hard coal power plant (ref. 2, 4).

Flexibility Parameter	Average Plant	Post Flexibilisation
Start-up time (hours)	2 to 10	1.3 to 6
Start-up cost (USD/MW instant start)	> 100	>100
Minimum load (% P_{nom})	25 to 40%	10 to 20%
Efficiency (at 100% load)	43%	43%
Efficiency (at 50% load)	40%	40%
Avg. Ramp Rate (%P_{nom}/min)	1.5 to 4%	3 to 6%
Minimum uptime (hours)	48	8
Minimum Downtime (hours)	48	8

The estimation of cost for flexibility improvement solutions can vary on a case by case basis. A rough estimate suggests costs between 120,000 and 600,000 USD/MW (ref. 2, 4). Furthermore, a study conducted by COWI and Ea Energy Analyses, investigated the cost of various flexibility improvements for coal plants. The investment cost estimates from this study are summarized below[5].

Investment cost estimated for flexibility improvement solutions based on a study for 600 MW hard coal power plant (ref. 6).

Solution	Investment estimate (in USD for a 600 MW hard coal power plant)
Increase maximum load (Includes: 3-way valve and optionally bypass piping)	558,265
Lower minimum load (Includes: boiler circulation pump, connecting pipe work, control and stop valves, standby heating, electrical, instrumentation and programming of the DCS system)	1,898,101
Increased ramping speed Upgrade of DCS-system Refurbishment of pulverizes	 156,314 424,281

Input

The process is primarily based on coal but will be applicable to other fuels such as wood pellets and natural gas.

Output

Electricity. The auxiliary power need for a 500 MW plant is 40-45 MW, and the net electricity efficiency is thus 3.7-4.3 percentage points lower than the gross efficiency (ref. 2).

[5] The conversion rate applied is 1 EUR = 1.12 USD (2019 exchange rate from the World Bank).

Typical capacities
Subcritical power plant can be from 30 MW and upwards. Supercritical and ultra-supercritical power plants have to be larger and are usually from 400 MW to 1500 MW (ref. 3).

Ramping configurations
Pulverized fuel power plants are able to deliver both frequency control and load support. Advanced units are in general able to deliver 5% of their rated capacity as frequency control within 30 seconds at loads between 50% and 90%.

This fast load control is achieved by utilizing certain water/steam buffers within the unit. The load support control takes over after approximately 5 minutes, when the frequency control function has utilized its water/steam buffers. The load support control is able to sustain the 5% load rise achieved by the frequency load control and even further to increase the load (if not already at maximum load) by running up the boiler load.

Negative load changes can also be achieved by by-passing steam (past the turbine) or by closure of the turbine steam valves and subsequent reduction of boiler load.

Advantages/disadvantages
Advantages:
- Mature and well-known technology.
- The efficiencies are not reduced as significantly at part load compared to full load as with combined cycle-plants.

Disadvantages:
- Coal fired power plants emit high concentrations of NOx, SO2 and particle matter (PM), which have high societal costs in terms of health problems and in the worst-case death.
- The burning of coal is the biggest emitter per CO_2 emission per energy unit output, even for a supercritical power plant.
- Coal fired power plants using the advanced steam cycle (supercritical) possess the same fuel flexibility as the conventional boiler technology. However, supercritical plants have higher requirements concerning fuel quality. Inexpensive heavy fuel oil cannot be burned due to materials like vanadium, without the steam temperature (and hence efficiency) is being reduced, and biomass fuels may cause corrosion and scaling, if not handled properly.

Environment
The burning and combustion of coal creates the products CO_2, CO, H_2O, SO_2, NO_2, NO and other particle matter (PM). CO, NOx and SO_2 are locally poison for the brain and lung, causing headaches and shortness of breath, and in worst case death. CO_2 is causing global warming and thereby climate changes. (ref. 3)

It is possible to implement filters for NOx and SO_2. In Indonesia, it is currently the Ministry of Environment Decree no. 21/2008 on stationary sources of air pollutants that states the maximum pollution from fossil fuel fired power plants.

Employment
The PLTU Adipala 700 MW supercritical power plant have employed 2000 full time employees in the construction phase. Hereof 500 was hired from the local villages.

Research and development
Conventional supercritical coal technology is fairly well established and so there appear to be no major breakthroughs ahead (category 4). There is very limited scope to improve the cycle thermodynamically. It is more likely that the application of new materials will allow higher efficiencies, though this is unlikely to come at a significantly lower cost (ref. 4).

Investment cost estimations, overview of examples of costs
Investment costs for coal power plants are very sensitive to the plant's design. Supercritical power plants use once-through boilers which contribute to cost increases; in state-of-the-art plants, efficiency gains in the order of a few percent are obtained through a well-thought design of machines and feedwater preheating. This remarkably increases overnight expenses.
Another important factor that greatly affect costs is the presence of sophisticated control systems, which are needed to optimize the functioning at partial load. Additional equipment for fault prediction also increases costs. Plants designed for base-load electricity supply are less expensive on average, and so are units forced to comply with very stringent environmental regulations.
The typical coal power plant in Indonesia operates in condensing mode, with no district heat production. Compared to other international figures (e.g. Denmark's), this indicates a less complicated design and therefore lower costs. It is therefore complicated to draw a comparison with other international values; all in all, coal power plants in Indonesia are found to be cheaper than the international average on a per-MW basis. The data below refers to supercritical power plants.

Investment costs [$MUSD_{2022}$/MW]	**2020**	**2023**	**2030**	**2050**
New Catalogue (2023)		**1.60**	**1.55**	**1.50**
Existing catalogue (2020)	1.60		1.55	1.50
MEMR FGDs[1]		1.40-2.00		
Viet Nam technology catalogue (2021)	-	1.66	1.65	1.42
IEA WEO 2023 (average of India and China)	1.00	1.00	1.00	1.00
IEA WEO 2023 (average of Europe and US)		2.05	2.05	2.05
Development curve - cost trend [%]		100%	98%	96%

[1] *MEMR Focus Group Discussions with various stakeholders for the purposes of updating the Technology Catalogue in 2023*

Examples of current projects
Ultra Super Critical Coal Power Plant: Jawa 7 Unit 1 Coal Power Plant. (Ref. 12)
Jawa 7 Unit 1 Coal Steam Power Plant (PLTU) with a total capacity of 1,000 MW was officially operational before the end of 2019. This coal-based power plant is considered to be the largest PLTU in Indonesia right now. It is located at Serang, Banten. This is the first coal-fired power plant in Indonesia that uses Ultra Super Critical (USC) boiler technology. The USC technology is projected to be able to increase the efficiency of the plant 15% higher than the non-USC, thereby reducing the cost of fuel per kWh. This also means higher greenhouse gas emissions reduction. This project is owned by PT Shenhua Guohua Pembangkitan Jawa Bali (PT SGPJB) which is a

consortium between China Shenhua Energy Company Limited (CSECL) and PT PJBI. The investment cost of Jawa 7 Unit 1 coal fired power plant is 13 trillion rupiahs or equivalent to 896.55 million USD. PLTU Jawa 7 uses SWFGD (Sea Water Fuel Gas Desulfurization) technology for coal handling. It is very environmentally friendly because coal handling from the barge to the plant uses a 4-kilometer long coal handling plant so that there is no scattered coal along the way to the coal yard. The electricity price of PLTU Jawa 7 is just 4.2 US cents/kWh. During construction, this project creates jobs for 4,000 workers. PLTU Jawa 7 Unit 2 with the same capacity will come online this year. In total, PLTU Jawa 7 will have installed capacity of 2 x 1000 MW this year. Then, the need for coal to run PLTU Jawa 7 Unit 1 and 2 would be around 7 (seven) million tons per year. This project uses low rank coal fuel which has heating value of 4000 to 4600 kCal/kg.

Jawa 7 Unit 1 USC Coal Fired Power Plant at Serang, Banten. (Ref. 13)

Super Critical Coal Power Plant: Cilacap Coal Power Plant (Ref. 14)

660 MW Cilacap Expansion 1 is one of the strategic projects and is located at Cilacap, Central Jawa. It came on line in February 2019. The Cilacap Expansion Coal Power Plant (PLTU) project was developed by PT Sumber Segara Primadaya (S2P) with a 51% stake and PT Pembangkitan Jawa Bali (PJB) with a 49% stake. The investment required for the development of this PLTU is almost USD 900 million and uses Super-Critical Boiler technology and can create jobs to 4000 workers during construction and 800 workers during its operation. The company agreed to sell the electricity to PLN at 854 rupiahs/kWh or it equals to 5.89 US cents/kWh. PLTU Cilacap Expansion 1 uses Super-Critical Boiler (SCB) fueled by Low Rank coal (4,200 kilo calories per kilogram) and is equipped with Electristastic Precipitator and Fluidized Gas Desulphurizaton (FGD) which are designed to operate efficiently and environmentally friendly.

Cilacap Expansion 1 Coal Power Plant in Central Jawa (Ref. 14)

References

The description in this chapter is to a great extend from the Danish Technology Catalogue *"Technology Data on Energy Plants - Generation of Electricity and District Heating, Energy Storage and Energy Carrier Generation and Conversion".* The following sources are used:

1. IEA and NEA, "Projected costs of generating electricity", 2015.
2. DEA, "Technology data for energy plants – Generation of electricity and district heating, energy storage and energy carrier generation and conversion", 2012.
3. Nag, "Power plant engineering", 2009.
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8. ISER, "Understanding flexibility of thermal power plants: Flexible coal power generation as a key to incorporate larger shares of renewable energy.," Jakarta, 2020.
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10. C. Henderson, "Improving the flexibility of coal-fired power plants," 2014.
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Data sheets

The following pages contain the data sheets of the technology. All costs are stated in U.S. dollars (USD), price year 2022. The uncertainty is related to the specific parameters and cannot be read vertically – meaning a product with e.g. lower efficiency does not have a lower price.

Technology

Technology	Subcritical coal power plant								
	2023	2030	2050	Uncertainty (2023)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	150	150	150	7	660	100	660	I	1
Generating capacity for total power plant (MWe)	300	300	300	7	2640	100	2640	I	1
Electricity efficiency, net (%), name plate	35	36	37	30	38	33	39		1,2,3
Electricity efficiency, net (%), annual average	34	35	36	29	37	32	38		1,2,3
Forced outage (%)	7	5	3	5	20	2	7	A	1
Planned outage (weeks per year)	6	5	3	3	8	2	4	A	1
Technical lifetime (years)	30	30	30	25	40	25	40		1
Construction time (years)	3	3	3	2	4	2	4		1
Space requirement (1000 m^2/MWe)	-	-	-	-	-	-	-		
Additional data for non thermal plants									
Capacity factor (%), theoretical	-	-	-	-	-	-	-		
Capacity factor (%), incl. outages	-	-	-	-	-	-	-		
Ramping configurations									
Ramping (% per minute)	3.5	3.5	3.5	2	4	2	4	B	1
Minimum load (% of full load)	40	40	40	25	50	20	40	A	1
Warm start-up time (hours)	3	3	3	1	5	1	5	B	1
Cold start-up time (hours)	8	8	8	5	12	5	12	B	1
Environment									
PM 2.5 (mg per Nm^3)	150	100	100	50	150	20	100	A,F	2,4
SO_2 (degree of desulphuring, %)	73	80	95	73	95	73	95	A,C,D	2,4
NO_X (g per GJ fuel)	263	150	38	263	263	263	263	A,D	2,4
CH_4 (g per GJ fuel)									
N_2O (g per GJ fuel)									
Financial data									
Nominal investment (M$/MWe)	1.88	1.82	1.76	1.14	1.94	1.14	1.94	E,H	1,3
- of which equipment									
- of which installation									
Fixed O&M ($/MWe/year)	51,600	50,000	48,550	38,750	64,500	36,500	60,800	G	1,3
Variable O&M ($/MWh)	1.50	1.45	1.40	1.00	1.80	1.00	1.70	G	1,3
Start-up costs ($/MWe/start-up)	125	125	125	57	228	57	228		5

References:

1 MEMR Focus Group Discussions with various stakeholders for the purposes of updating the Technology Catalogue in 2023

2 Platts Utility Data Institute (UDI) World Electric Power Plant Database (WEPP)

3 Learning curve approach for the development of financial parameters.

4 Maximum emission from Minister of Environment Regulation 21/2008

5 Deutsches Institut für Wirtschaftsforschung, On Start-up Costs of Thermal Power Plants in Markets with Increasing Shares of Fluctuating Renewables, 2016.

Notes:

A Assumed gradidual improvement to international standard in 2050.

B Assumed no improvement for regulatory capability.

C Indonesian sulphur content in coal is up to 360 g/GJ. Conversion factor 0.35 to mg/Nm3 yields 1030 mg/Nm3. With a max of 750 mg/Nm3 then gives a % of desulphuring of 73%.

D Calculated from a max of 750 mg/Nm3 to g/GJ (conversion factor 0.35 from Pollution Prevention and Abatement Handbook, 1998)

E For economy of scale a proportionality factor, a, of 0.8 is suggested.

F Uncertainty Upper is from regulation. Lower is from current standards in Japan (2020) and South Korea (2050).

G Uncertainty (Upper/Lower) is estimated as +/- 25%.

H Investment cost include the engineering, procurement and construction (EPC) cost. See description under Methodology.

I Based on data collection from Indonesian projects

Technology

Technology	Supercritical coal power plant								
	2023	2030	2050	Uncertainty (2023)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	600	600	600	250	800	250	800	I	1
Generating capacity for total power plant (MWe)	600	600	600	250	800	250	800	I	1
Electricity efficiency, net (%), name plate	38	39	40	33	40	35	42		1
Electricity efficiency, net (%), annual average	37	38	39	33	40	35	42		1
Forced outage (%)	7	6	3	5	15	2	7	A	1
Planned outage (weeks per year)	7	5	3	3	8	2	4	A	1
Technical lifetime (years)	30	30	30	25	40	25	40		1
Construction time (years)	4	3	3	3	5	2	4	A	1
Space requirement (1000 m^2/MWe)	-	-	-	-	-	-	-		
Additional data for non thermal plants									
Capacity factor (%), theoretical	-	-	-	-	-	-	-		
Capacity factor (%), incl. outages	-	-	-	-	-	-	-		
Ramping configurations									
Ramping (% per minute)	4	4	4	3	4	3	4	B	1
Minimum load (% of full load)	40	40	40	25	50	20	40	A	1
Warm start-up time (hours)	4	4	4	2	5	2	5	B	1
Cold start-up time (hours)	12	12	12	6	15	6	12	B	1
Environment									
PM 2.5 (mg per Nm^3)	150	100	100	50	150	20	100	F	2,4
SO_2 (degree of desulphuring, %)	73	73	73	73	95	73	95	C,D	2,4
NO_X (g per GJ fuel)	263	263	263	263	263	263	263	D	2,4
CH_4 (g per GJ fuel)	-	-	-	-	-	-	-		
N_2O (g per GJ fuel)	-	-	-	-	-	-	-		
Financial data									
Nominal investment (M$/MWe)	1.60	1.55	1.50	1.20	2.00	1.13	1.88	E,G,H	1,3,6
- of which equipment									
- of which installation									
Fixed O&M ($/MWe/year)	47,000	45,600	44,100	35,200	58,700	33,000	55,200	G	1,3,6
Variable O&M ($/MWh)	1.40	1.35	1.30	1.00	1.70	1.00	1.60	G	1,3
Start-up costs ($/MWe/start-up)	57	57	57						5

References:

1 MEMR Focus Group Discussions with various stakeholders for the purposes of updating the Technology Catalogue in 2023
2 Platts Utility Data Institute (UDI) World Electric Power Plant Database (WEPP)
3 Learning curve approach for the development of financial parameters.
4 Maximum emission from Minister of Environment Regulation 21/2008
5 Deutsches Institut für Wirtschaftsforschung, On Start-up Costs of Thermal Power Plants in Markets with Increasing Shares of Fluctuating Renewables, 2016.
6 IEA, World Energy Outlook, 2023

Notes:

A Assumed gradidual improvement to international standard in 2050.
B Assumed no improvement for regulatory capability.
C Indonesian sulphur content in coal is up to 360 g/GJ. Conversion factor 0.35 to mg/Nm3 yields 1030 mg/Nm3. With a max of 750 mg/Nm3 then gives a % of desulphuring of 73%.
D Calculated from a max of 750 mg/Nm3 to g/GJ (conversion factor 0.35 from Pollution Prevention and Abatement Handbook, 1998)
E For economy of scale a proportionality factor, a, of 0.85 is suggested.
F Uncertainty Upper is from regulation. Lower is from current standards in Japan (2020) and South Korea (2050).
G Uncertainty (Upper/Lower) is estimated as +/- 25%.
H Investment cost include the engineering, procurement and construction (EPC) cost. See description under Methodology.
I Based on data collection from Indonesian projects

Technology

Technology	Ultra-supercritical coal power plant								
	2023	2030	2050	Uncertainty (2023)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	1000	1000	1000	700	1200	700	1200	I	1
Generating capacity for total power plant (MWe)	2000	2000	2000	700	1200	700	1200	I	1
Electricity efficiency, net (%), name plate	42.5	44	45	40	45	42	47		1,3
Electricity efficiency, net (%), annual average	42	43	44	40	45	42	47		1,3
Forced outage (%)	7	6	3	5	15	2	7	A	1
Planned outage (weeks per year)	7	5	3	3	8	2	4	A	1
Technical lifetime (years)	30	30	30	25	40	25	40		1
Construction time (years)	4.3	3	3	3	5	2	4	A	1
Space requirement (1000 m^2/MWe)	-	-	-	-	-	-	-		
Additional data for non thermal plants									
Capacity factor (%), theoretical	-	-	-	-	-	-	-		
Capacity factor (%), incl. outages	-	-	-	-	-	-	-		
Ramping configurations									
Ramping (% per minute)	5	5	5	4	5	4	5	B	1
Minimum load (% of full load)	40	40	40	25	50	20	40	A	1
Warm start-up time (hours)	4	4	4	2	5	2	5	B	1
Cold start-up time (hours)	12	12	12	6	15	6	12	B	1
Environment									
PM 2.5 (mg per Nm^3)	150	100	100	50	150	20	100	F	2,4
SO_2 (degree of desulphuring, %)	73	73	73	73	95	73	95	C,D	2,4
NO_X (g per GJ fuel)	263	263	263	263	263	263	263	D	2,4
CH_4 (g per GJ fuel)	-	-	-	-	-	-	-		
N_2O (g per GJ fuel)	-	-	-	-	-	-	-		
Financial data									
Nominal investment (M$/MWe)	1.73	1.68	1.63	1.30	2.17	1.22	2.04	E,G,H	1,3,6
- of which equipment									
- of which installation									
Fixed O&M ($/MWe/year)	64,500	62,500	60,600	48,450	80,700	45,500	75,800	G	1,3,6
Variable O&M ($/MWh)	1.25	1.20	1.15	0.90	1.60	0.90	1.50	G	1,3
Start-up costs ($/MWe/start-up)	57	57	57	45.6	114	45.6	114		5

References:

1 MEMR Focus Group Discussions with various stakeholders for the purposes of updating the Technology Catalogue in 2023
2 Platts Utility Data Institute (UDI) World Electric Power Plant Database (WEPP)
3 Learning curve approach for the development of financial parameters.
4 Maximum emission from Minister of Environment Regulation 21/2008
5 Deutsches Institut für Wirtschaftsforschung, On Start-up Costs of Thermal Power Plants in Markets with Increasing Shares of Fluctuating Renewables, 2016.
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D Calculated from a max of 750 mg/Nm3 to g/GJ (conversion factor 0.35 from Pollution Prevention and Abatement Handbook, 1998)
E For economy of scale a proportionality factor, a, of 0.85 is suggested.
F Uncertainty Upper is from regulation. Lower is from current standards in Japan (2020) and South Korea (2050).
G Uncertainty (Upper/Lower) is estimated as +/- 25%.
H Investment cost include the engineering, procurement and construction (EPC) cost. See description under Methodology.
I Based on data collection from Indonesian projects

7. Coal Power Plant - Integrated Gasification Combined Cycle (IGCC)

IGCC power plants can play an important role in countries that consider coal a main source for power production. They can reach higher efficiencies than conventional coal plants and they can use lower quality coal. When it comes to emissions, they emit less pollutants, such as sulphur dioxide (SO_2), nitrogen oxide (NOx) and particulate matter (PM) than other coal technologies. Regarding Carbon capture, CO_2 pre-combustion capture is less costly than post-combustion capture from the flue gases.

The first IGCC power plants started operating in the mid-nineties as demonstration plants, mainly in Europe and the USA. Some of them were closed due to the high costs compared to energy prices, partly caused by the drop in natural gas prices, what caused the conversion of a number of operational plants to gas. There was a second wave of IGCC plants from 2010 onwards in the USA and Asia. Most of these have or intend to install Carbon Capture technologies and an increasing number of plants have oxygen blown systems. Most of the projects from 2019 on are either in Japan, China or the UK. Japan is currently constructing two high-efficiency 540 MW IGCC plants in the Fukushima area. The UK proposals are unlikely to proceed due to reduced CCS funding, whereas China has over 180 proposed projects in the pipeline, which shows commitment to IGCC deployment. Nonetheless, it is unclear whether many of these will reach the construction phase.

Technology Description

Coal gasification is a thermo-chemical process in which coal is first converted into a synthesis gas (syngas), which then fires a gas cycle, typically a combined-cycle gas turbine. Two main sections can be identified in an IGCC plant, the gasification and the combined cycle (CC).

The process starts by gasifying coal with limited amounts of either oxygen or air. The combination of high temperature and pressure conditions with limited amounts of oxygen allows only some of the organic materials to get burned. This triggers a second reduction reaction that produces a fuel-rich gaseous mix of hydrogen and carbon monoxide known as syngas. Gasifiers operate at temperatures up to 1300°C. Heat is recovered after the gasification process to vaporize steam which is sent to turbines for expansion. Heat recovery is usually performed through radiant (high-temperature) and convective (low-temperature) syngas coolers; however, other cooling options are possible, such as partial or full quenching. The heat recovery process is performed in different stages, depending on operating temperature of the subsequent cleaning equipment. After the radiant section, the syngas goes through cyclones and/or scrubbers in order to get rid of big particles, alkaline metals and nitrogen compounds. The removal of big particles is important to minimize soiling in the convective heat exchangers which follow on the plant layout. Before it is sent to the gas cycle, other unwanted substances (mainly acids, sulfur in particular, but also mercury, unconverted carbon and even carbon dioxide) are removed. After that, the syngas can be used to power a gas cycle. The whole energy efficiency of the gasification process is often referred to as *cold gas efficiency*, which can be assumed to be around 75-80%.

The syngas then feeds a combined cycle. The exhaust gases go through a heat recovery steam generator (HRSG), which produces steam for the bottoming section of the combined cycle (ref. 1).

IGCC gasifiers are not standardized and each manufacturer designs their own. The main variations are:

- **Gasification agent**: It can be air or oxygen, the latter being more common (ref. 2). Steam is generally added, unless low-quality coal rich in water is used.
- **Gasifier type**:

  Entrained-Flow Gasifiers, where coal particles react with the concurrent steam and oxygen flow. The residence time is a few seconds, and the operating temperature above ash fusion.

Pressurized gasification is preferred for IGCC to avoid large auxiliary power losses in the compression of the syngas to the gas turbine pressure.

Moving-Bed Gasifier, where coal moves downwards and the syngas in the opposite direction (updraft). The operating temperature can reach more than 1200°C.

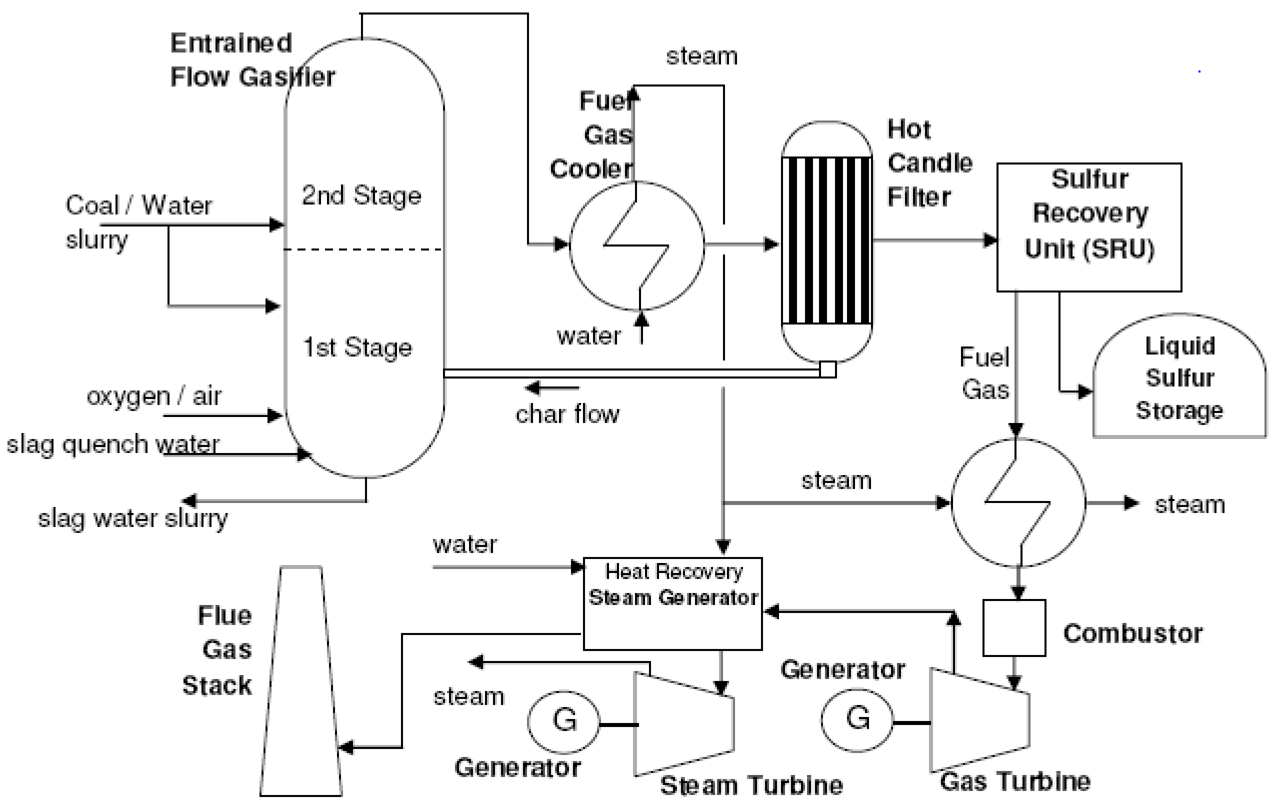
Fluidized-Bed Gasifiers have coal suspended in an oxygen-rich gas, so the resulting bed will act as a fluid. The syngas exits the gasifier from the top. They can operate at lower temperatures compared to other gasifiers (< 1000°C) (ref. 1).

- **Syngas cooling** happens through heat exchangers:

  Radiant coolers are radiant type heat exchangers with cage shaped tubes, where water in the secondary circuit gets heated and the temperature of the syngas is reduced (high-temperature cooling).

  Convective syngas coolers are usually shell and tube type heat exchangers. They are used after the radiative cooling (ref. 3).

- **Syngas cleaning**. Physical or chemical absorption processes via solvents, sorbents and membranes are used (ref. 4).



IGCC plant scheme using entrained flow gasifier technology (ref. 5).

The power block in an IGCC plant is very similar to a standard combined cycle (CC). However, some differences exist. The syngas has a lower calorific value than natural gas and H_2 – which can be assumed to make up roughly 35% of the syngas in volume - cannot be pre-mixed before combustion (due to H_2 high flame speed). A lower calorific value requires a higher fuel mass flowrate to reach the same cycle performance, which in turn results in a higher pressure at the final compressor stages. Nitrogen needs to be added in the combustion chamber to decrease diffusivity and NOx formation.

Input
The main fuel is coal in its low rank form or petcoke (ref. 6). As a secondary input, oxygen or air are necessary for the gasification process. Steam can be necessary, but it is produced in the IGCC.

The auxiliary consumption varies depending on the used gasifier. Air-blown systems are estimated to consume less than 8% of the output power, while oxygen-blown systems account for around 10-15% of the power of the plant according to the CTCN (ref. 7) and the Clean Coal Centre. Additional consumption is due to the Air Separation Unit. Gas clean-up and/or CO_2 capture can reduce CO_2 emissions up to 90%. Nonetheless, the cost of CO_2 capture is very substantial and will also increase the auxiliary consumption of the plant (ref. 8). The power output decreases by about 11% at 60% capture and by about 16% at 80% capture (ref. 10) and 7-11% as stated by the Clean Coal Centre.

Output
The main output is electricity. Heat could also be produced for process heating. Sulfur, produced as a high-purity liquid, is a highly marketable product. Alternatively, if the plant is located close to a sizeable market, sulfuric acid synthesis is an option. Slag is also potentially marketable (ref. 10).

The overall electric efficiency of existing IGCC plants lies around 42%, which is comparable, albeit slightly lower, to that of supercritical coal plants. The installation of new IGCCs could bolster the R&D in the technology and contribute to reaching higher efficiencies; new demonstration projects in Japan have proven that a 48% efficiency can be attained.

Typical Capacities
The typical capacities are 250-300 MW (ref. 11) or 500-600 MW (*ref. 8*), as evident from the latest IGCC projects in Japan.

Ramping Configurations
The minimum load is normally 50%, although the Nakoso #10 plant in Japan showed that 36% minimum load could be achieved. The current capability for IGCC ramping is typically 3% /minute (ref. 12), but efforts aim at reaching ramping rates of 5%/minute.

Advantages
- IGCC allows high plant efficiencies while meeting stringent air emission standards (ref. 1). CO_2 can be removed prior to feeding the syngas to the turbine, capturing 80-90% of it.
- Gasifiers can deal with coal that pulverized coal plants cannot use, due to the high sulfur or ash content and other residues (ref. 7).
- Countries with abundant coal reserves can use IGCCs (possibly with pre-combustion carbon capture) for power production instead of traditional coal power plants. IGCCs offer an environmentally superior performance than pulverized coal plants, with a CO_2 concentration in the exhaust gas stream.

- IGCC plants have achieved the lowest levels of criteria in pollutant air emissions of any coal fueled power plant (ref. 7).
- Compared to the existing coal power fleet in Indonesia, deployment of IGCC could substantially increase the efficiency of coal utilization, improve Indonesia's energy security and reduce the emission of pollutants (ref. 14).
- IGCC plants can use up to 30% less water than conventional Pulverized Coal (PC) plants because the steam cycle is only part of the power production (ref. 1).
- Instead of generating fly and bottom ash (which is more complicated to treat) as in conventional coal-fired power plants, IGCC produce a marketable molten slag by-product. This can for instance be used in the cement and asphalt industries.

Disadvantages

- Construction cost is high compared to supercritical coal fired power plants.
- High O&M costs (ref. 16).
- The toxic gases that contain CO and H_2S require additional precaution.
- The technical complexity increases the risk of unforeseen costs and operational problems.

Being able to treat a considerable portion of the environmentally hazardous substances comes at a cost. The overnight cost of power plant construction and the LCOE are high for IGCC and higher for IGCC with carbon capture when compared to other fossil-fueled power generation technologies (ref. 15, 16).

Environment

As mentioned above, IGCC plants intend to minimize the polluting emissions, nonetheless, some are still present. The following list includes the major pollutants:

- Most of the sulfur in the coal converts to H_2S or COS in the gasification and is later removed prior to combustion, but the remaining sulfur turns into **SO_2**.
- **NO_x** forms in fossil combustions (NO & NO_2). Due to the limited amount of oxygen, mostly N_2 is formed, but besides NO_x, a small portion is still converted to NH_3 (ammonia) and Hydrogen cyanide (HCN).
- **CO** is emitted as a result of incomplete combustions.
- **Lead** is released during combustion and gasification. One third ends up as slag and 5 % as air emissions. The remaining is assumed to be removed by acid gas clean-up.
- **Slag** is discharged from the gasifier and PM containing **ash** can be removed by using cyclone, filters, wet scrubbers and acid gas removal (AGR).
- **Mercury** can be gotten rid of with gas or wet scrubbers. It is more of an economic issue than a technical one.
- **Aqueous Effluents**. Wastewater from the steam cycle & water blowdown, high in dissolved solids and gases.
- The largest Greenhouse Gas emitted by IGCC is **CO_2**.
- Discharge of solid byproduct and wastewater is reduced by 50% compared to direct fire combustion. Some of the generated by-products can be sold as valuable products like sulfur (ref. 14).

IGCC and Carbon Capture

To be able to capture CO_2 from syngas it needs to go through a water-gas-shift (WGS) reactor, which converts the CO to CO_2 and the H_2 concentration is increased. This CO_2 is at a high pressure, which makes it easier and cheaper to capture compared to post combustion processes, where the flue gas needs to be compressed, causing a high auxiliary load (Carbon Dioxide Capture Approaches). This makes the separation of carbon dioxide much cheaper than for systems with post-combustion capture (IGCC with Carbon Capture and Storage).

Employment

The existing coal based IGCC demonstration projects face competition in continuing to operate over the next few years due to deregulation and reduced subsidiaries. In the U.S and Europe they must compete with power from natural gas-based turbines and combined cycles.

A plant with 2 units of 600 MW requires 3000 employees for the construction and 200 employees for the operation and maintenance (ref. 17).

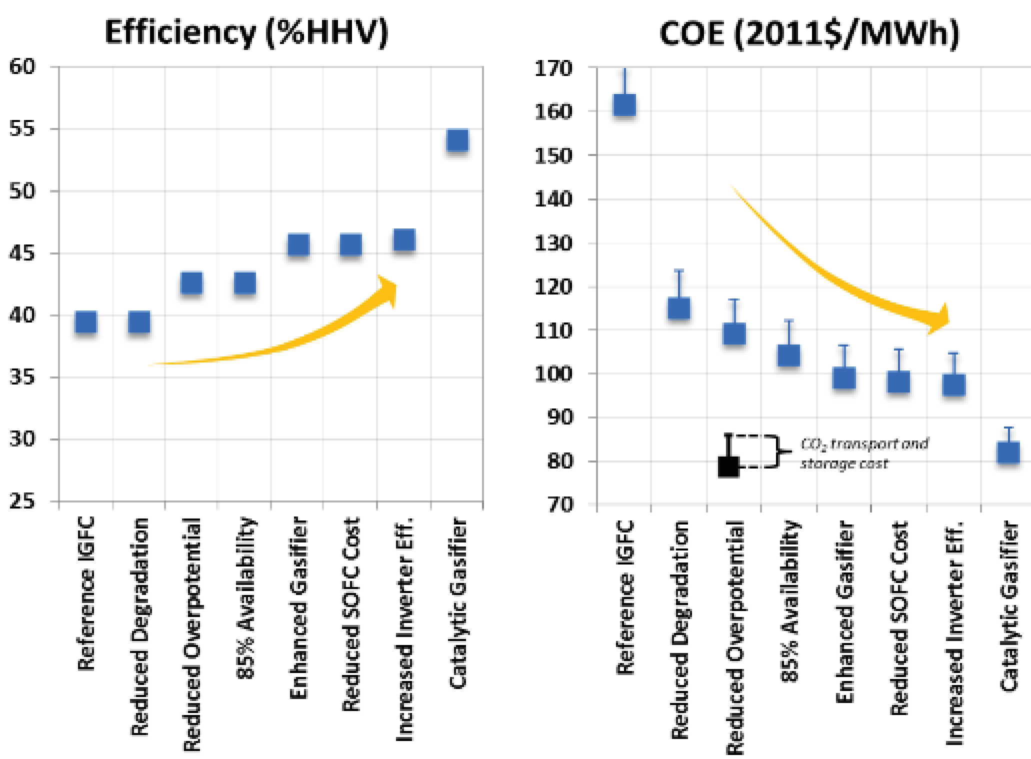
Research and development

The research and development of second-generation technologies is targeted to achieve a 20% reduction in cost of energy compared to the state-of-the-art technology of 2012 according to the US Department of Energy and NETL (ref. 18).

The pathways are built up to incorporate these technologies in a cumulative manner:

1st Advanced Hydrogen Turbine (AHT)
2nd Ion Transport Membrane (ITM)
3rd Warm Gas Clean Up (WGCU)
4th Hydrogen membrane for pre-combustion capture (Hydrogen Membrane)

By applying these, there is an increase in efficiency and a reduction in the Cost of Energy generated.



Change in efficiency and cost as different measures are implemented (ref. 18)

Examples of current projects

Eight major coal-based IGCC power stations had been put into operation by 2020 (ref. 19). The International Energy Agency (IEA) states that many IGCC projects have been announced, but failed to proceed. At least 18 planned IGCC plants have been cancelled, shelved or put on hold globally from 2011 to 2015 alone, according to publicly available data (ref. 20). These abandonments are mainly due to climate concerns, elimination of coal plants from long-term plans, insufficient financing and raise of construction costs (ref. 21). Below, some of the existing plants are presented.

Duke Energy´s Edwardsport IGCC (USA)

The 618 MW plant got approval to be built on 2007 and started operations in 2013. Its cost was estimated to be $1.9 billion, however, the final price ended up being $3.5 billion. This cost overrun was mainly due to numerous construction problems and wrong estimates of amounts of piping, steel and concrete needed. Other issues were labor productivity and an unforeseen water-disposal system (ref. 23).

During the first four years of operation, the average O&M costs for power generation were around 60 $/MWh, while the wholesale market electricity costs averaged slightly above 31 $/MWh (*ref. 23*). The director of resource planning from IEEFA blames the high O&M costs on both trains of the gasification plant not operating in tandem, tandem meaning that the two combustion turbines and two steam turbines are producing electricity. He states that unless it is operating in those conditions the plant is uneconomical (ref. 24).

Kemper County (USA)

The construction began in 2011 and started operating in 2016 to produce 582 MW. It captures 65% of the CO_2 emissions. The initial investment cap was $2.4 billion but was raised to $3.42 billion, nonetheless, ended up costing $7.5 billion.

Due to a pressed schedule, caused by significant delays from material contractors and suppliers, the design of the plant was taking place at the same time as the building phase. This impacted the initially low cost estimates, which had not accounted for enough contingency (ref. 25). The cost increase is a result of labor costs and productivity, adverse weather conditions, shortage and inconsistent quality of equipment (ref. 26).

The failure is attributed to an oversized scale-up from the demonstration plant, which was 7 MW. Apparently, the problems are due to the system components upstream of the capture stage, in the gasification part of the plant. Nonetheless, other projects demonstrate that capturing CO_2 from coal plants is indeed feasible in the US (ref. 27). One of the reasons for building this plant was the stable price of lignite compared to natural gas, but when the price of natural gas decreased, due to newly found natural gas troves in the US, it became uncompetitive against natural gas combined cycles (ref. 28). Therefore, it is now operating with natural gas and no carbon capture.

Huaneng Tianjin (China)

This project is not only using IGCC technology, it is a demonstration project for Clean Coal Technologies GreenGen, but the first stage was an IGCC plant, which began operating in 2005 (ref. 29). The IGCC capacity is 250 MW with a cost of 528.4 USD million.

Nakoso #10, 250 MW (Japan)

The plant was initiated in 2007 as a demonstration plant and it was later converted to become the first commercial IGCC Plant in Japan since 2013. Since then, it has been operating for more than 50,000 hours, and exceeding all the necessary parameter targets such as higher net output (225 MW against 220 MW), higher net efficiency (42.9% against 42%), superior SO_X (1 ppm against 8 ppm@16%O2,dry basis) NOX (3.4 ppm against 5 ppm@16%O2,dry basis) particulate matter (0.1 mg/m3N against 4 mg/m3N@16%O2,dry basis), faster start up time (15 hours against 18 hours), lower minimum load (36% against 50%) and long-term continuous operation (3917 hours against 2000 hours).

Nakoso 540 MW (Japan)
As part of Japanese Government initiatives to revitalize Fukushima area after the nuclear disaster, the Nakoso 540 MW started construction in April 2017. It utilizes air blown gasifier, MDEA gas clean up and high efficiency F-class gas turbine in one-on-one configuration, resulting in nominal efficiencies up to 48% LHV.

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Data sheets

The following pages contain the data sheets of the technology. All costs are stated in U.S. dollars (USD), price year 2022. The uncertainty is related to the specific parameters and cannot be read vertically – meaning a product with e.g. lower efficiency does not have a lower price.

Technology

Technology	Coal, Integrated Gasification Combined Cycle (IGCC)								
	2023	2030	2050	Uncertainty (2023)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	200	200	200					A	
Generating capacity for total power plant (MWe)	600	600	600					A	1
Electricity efficiency, net (%), name plate	42	43	45					G	1
Electricity efficiency, net (%), annual average	40	41	43					G	
Cold gas efficiency (%)	75	80	80					B	
Forced outage (%)	5.5	6.0	6.0						2
Planned outage (weeks per year)	6.6	7.0	7.0					C	3
Technical lifetime (years)	30	30	30						1
Construction time (years)	4	4	4						4
Space requirement (1000 m^2/MWe)	-	-	-	-	-	-	-		
Additional data for non thermal plants									
Capacity factor (%), theoretical	-	-	-	-	-	-	-		
Capacity factor (%), incl. outages	-	-	-	-	-	-	-		
Ramping configurations									
Ramping (% per minute)	3.0	3.5	5.0					D	5
Minimum load (% of full load)	50	40	30					D	5
Warm start-up time (hours)	6	6	6						10,11
Cold start-up time (hours)	40	40	40	15	80	15	80	F	10,11
Environment									
PM 2.5 (mg per Nm3)	115	100	100						7,12
SO_2 (degree of desulphuring, %)	99	99	99						9,12
NO_X (g per GJ fuel)	173	52	49						7,12
CO (g per GJ fuel)									
Financial data									
Nominal investment (M$/MWe)	2.73	2.51	2.32	2.46	3.99	2.00	3.42	H	6,13
- of which equipment (%)	30	30	30	25	50	25	50		6,13
- of which installation (%)	70	70	70	50	75	50	75		6
Fixed O&M ($/MWe/year)	68,400	66,300	64,300	64,000	78,000	64,000	78,000		6
Variable O&M ($/MWh)	13.70	13.30	12.90	18.20	9.00	19.00	9.00		6,13
Start-up costs ($/MWe/start-up)	114	114	114					E	

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13 NREL ATB 2020

Notes:

A IGCCs use combined (gas) cycles to produce power. Their efficiency is higher for big plant sizes (economy of scale). Preliminary screenings in Sumatra and Kalimantan identify in 150-200 MW the IGCC size.

B The cold gas efficiency is the efficiency of the gasification unit

C Unplanned outages can be sizeable. These mainly concern corrosion and fouling in the heat exchangers, particularly the syngas coolers.

D It is assumed that improvements in the air sepration unit (ASU) and in the gasification unit boost the cycle's ramping capabilities in the coming years

E Start-up costs vary depending on the idle time. Warm-up of the gasification unit requires time and can be expensive, therefore start-up cost is higher than a CC plant.

F Start-up time is the necessary time to reach minimum load. It takes a long time for IGCC to reach full-load and it can vary depending on the specific technology, hence the wide range.

G The efficiency is strongly dependent on coal type. High-grade coal can lead to efficiencies of over 45%, but low-rank coal (3-4000 kcal/kg) used in Indonesia leads to lower efficiencies with today's technology.

H Price for one unit. An IGCC power plant consisting of two units can be considered to have a 10% lower overnight cost

8. Retrofit of Coal Plants - Ammonia Co-Firing in Coal Power Plants

Brief technology description

Ammonia co-firing in pulverized coal-fired power plants is a technology that involves using ammonia (NH_3) as a substitute fuel for a portion of the coal. The pulverized coal and ammonia are both fed into the furnace from modified burners.

Using ammonia as a fuel in co-firing operations could decrease the CO_2 emissions of coal-fired power plants. Additionally, as ammonia combustion produces less soot and particulate matter, this can also lead to reduced ash build-up on heat transfer surfaces, resulting in improved boiler performance. However, the low flame temperature and narrow combustible temperature range of ammonia can make it difficult to keep the flame stable during co-firing. The possible formation of significant amounts of NO_x from ammonia is a concern. However, NOx removal systems using selective catalytic reduction (SCR) technology, which converts nitrogen oxides into diatomic nitrogen and water could effectively solve the problem (ref. 6).

The diagram of ammonia co-firing technology is shown in figure below:

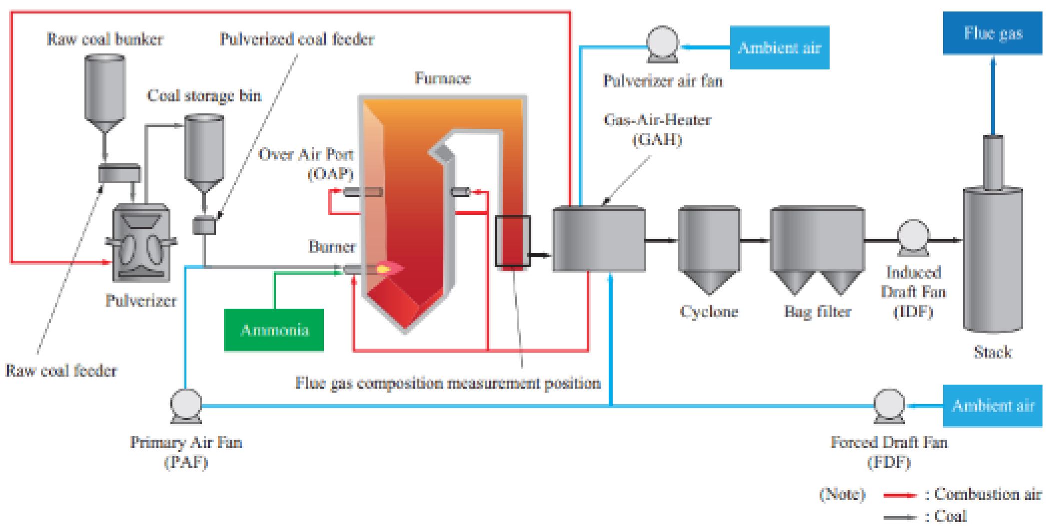


Diagram of ammonia co-firing in pulverized coal-fired power plants (ref. 1)

The required modifications to the boiler system when co-firing ammonia in a pulverized coal were examined in (ref. 1). The findings of the study are summarized (ref. 1):

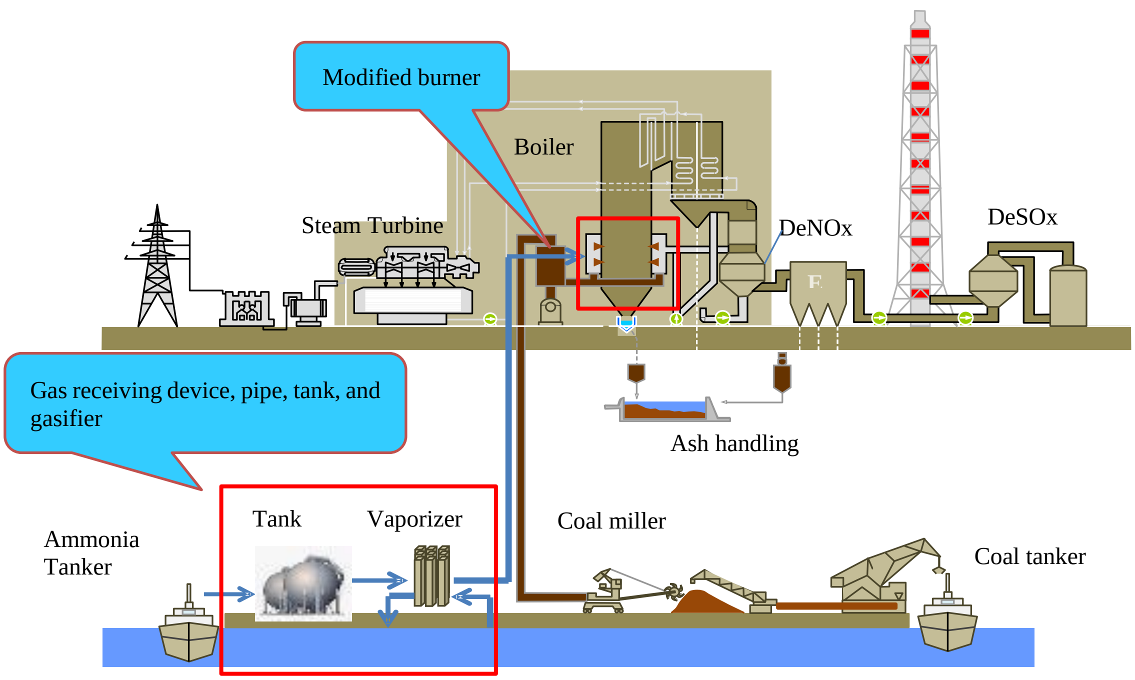
- Heating surfaces of the boiler: No need of modification - the heat recovery quantity is almost the same for coal firing and ammonia co-firing, and the steam and gas temperatures throughout the system are not different.
- Burner: Some modification. The burners designed for coal firing are also used for ammonia co-firing. However, it is necessary to add ammonia supply facilities, such as including equipment that injects ammonia gas into the burner.
- Primary Air Fan (PAF): No modification. The amount of air used to carry coal only decreases when ammonia co-firing is added.

- Forced Draft Fan (FDF): Consideration is required to determine whether modification is needed. The air required for combustion is supplied by the PAF and FDF. During ammonia co-firing, the amount of air supplied by the PAF decreases, and the FDF has to compensate for this in order to ensure the required amount of air for combustion. Hence, the flow rate on the FDF side tends to increase. Depending on the design specification, surplus FDF capacity may or may not exist.
- Induced Draft Fan (IDF): Careful consideration is required, since modification may be needed depending on the setting in which surplus capacity is ensured (as with the FDF).
- Pulverizer: No modification of the pulverizer is necessary. The amount of injected coal decreases for ammonia co-firing so the operation load of the pulverizer decreases.
- Gas Air Heater (GAH): No modification of the GAH is required.
- Environmental facilities (NOx removal equipment, removal equipment): There is an increase in the amount of gas and moisture content of the flue gas, so it is necessary to further evaluate modification and expansion of environmental facilities.

Modifying existing coal plants for ammonia co-firing requires boiler modifications and investment in additional facilities like ammonia tanks and vaporizers. In general, the retrofits include (ref. 2):

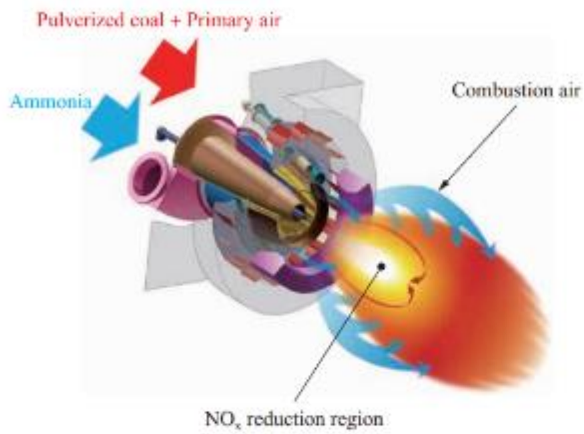
- Modified burner.
- New ammonia receiving device, pipe, tank and vaporizer.
- Additional NO_x removal device

This is illustrated in the figure below.



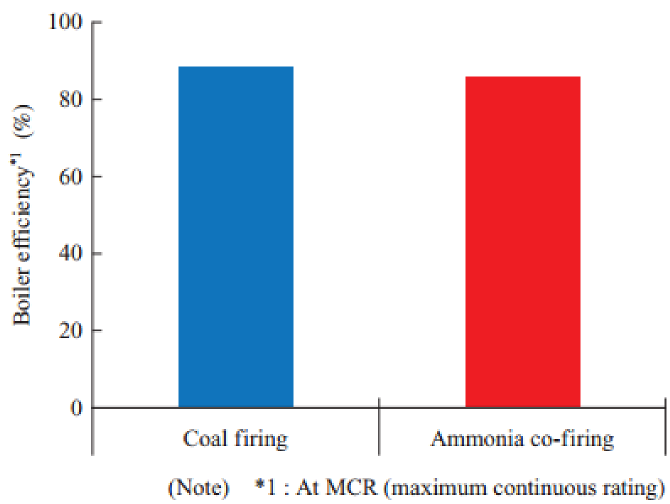
Facilities to be implemented and improved at a coal ammonia co-fired power plant

Figures below shows a schematic diagram of the modified burner to co-firing ammonia, adding the necessary equipment injecting ammonia. Some combustion tests show that a stable flame when co-firing ammonia can be archived by supplying ammonia from the center of the modified burner. In this way, the NO_x emission is also being limited (ref. 1).



Schematic diagram of the modified burner to co-firing ammonia (ref. 1)

Effect on boiler efficiency
The boiler performance between a coal-firing and an ammonia co-firing at 20% plant was compared in (ref. 1). The result shows that the boiler efficiency during ammonia co-firing is slightly lower than that during coal firing. This is presumably because, although ammonia co-firing reduces the loss due to unburned coal, burning ammonia increases the moisture content in the boiler flue gas, which increases the latent heat of the moisture discharged from the gas.



Comparison of boiler performance for coal firing and ammonia co-firing 20% (ref. 1)

Ramping configurations
Effect on operation characteristic
The regulation abilities including ramp rate, minimum load and start up time will not change much in case existing boilers of coal fired plants are co-firing with ammonia.

Advantages/disadvantages
There are both potential benefits and drawback to the use of ammonia co-firing in coal-fired power plants:

Advantages:

- As ammonia is a non-carbon fuel, it does not emit carbon dioxide during combustion. Therefore, ammonia co-firing could reduce CO_2 emission of coal-fired power plants. With the co-firing ratio of 50%, CO_2 emission of co-firing coal power plant will be equivalent level to gas-fired power generation (ref. 2).
- Ammonia could be utilized directly as a fuel without cracking. Ammonia co-firing reduces the amount of soot and coal power particles in the furnace, leading to reduced ash deposition on heat transfer surfaces.
- Transmission of ammonia via pipelines is a mature technology. Ammonia is also well developed in terms of intercontinental transmission, relying on semi-refrigerated liquefied petroleum gas (LPG) tankers.

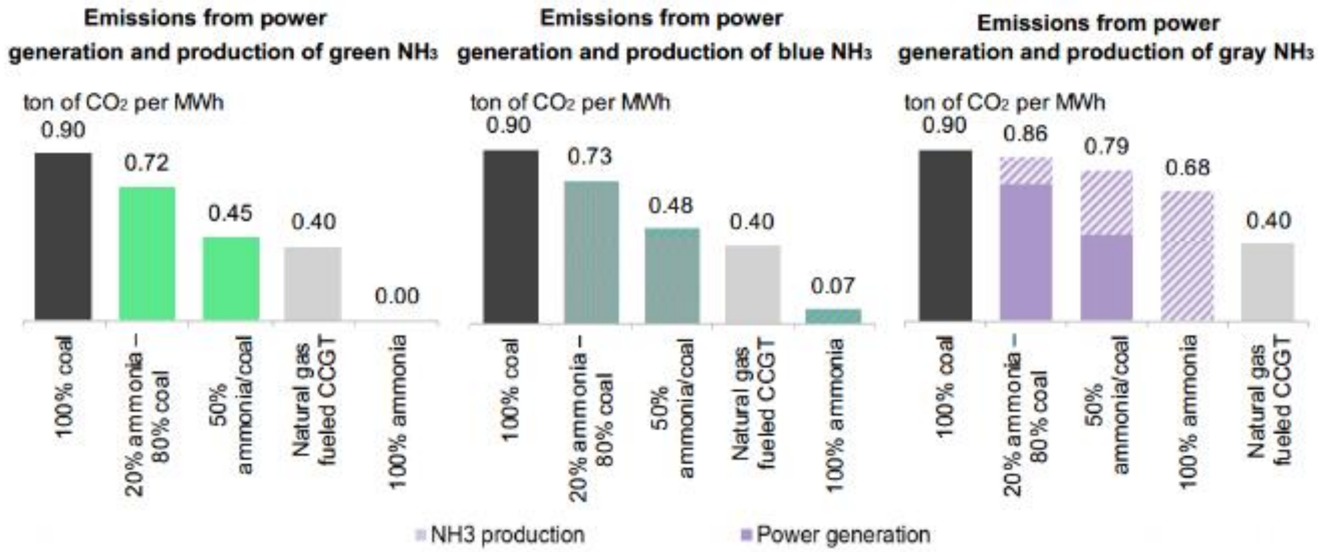
Disadvantages:

- Ammonia is a highly reactive and toxic gas, and proper safety measures must be in place to prevent accidents or releases.
- Ammonia co-firing requires modified burners and other facilities to retrieve, vaporize and transport ammonia. Moreover, additional NO_x removal systems (selective catalytic reduction SCR) are also required, due to the significant amounts of NO_x generated during combustion. Those modification and implementation can be costly.
- The price of ammonia is higher than that of coal, increasing fuel costs for the plant. An estimation of the Institute of Energy Economics, Japan projected that the fuel costs for a power plant that uses a 20% blend of ammonia will be significantly higher, more than double, than that of a power plant which uses coal alone (ref. 5).
- Currently, more than 90% of ammonia is synthesized from nitrogen in the air and hydrogen produced from fossil fuels, such as natural gas, coal, and oil without carbon capture and storage (grey ammonia). This process still emits large amount of CO_2. Other kinds of ammonia like blue ammonia (made via steam reforming of methane or gasification of coal couple with CO_2 capture and storage), or green ammonia (made via electrolysis of water using renewable energy electricity) release smaller volumes of CO_2 but are more costly solutions.
- Further research is needed to increase the NH_3-to-coal ratio and improve the efficiency of the boiler.

Environment

Effects on emissions

Reduction in CO_2 emissions is the main advantage of ammonia co-firing at coal power plants. The following graph shows the emission reduction potential depending on the ammonia source, with green ammonia offering the best option.



Emission reduction potential depending on the ammonia source (ref. 2)

Note: Emissions for power generation and ammonia production. Grey (unabated) ammonia production assumes 9kg of CO_2 emissions to produce 1kg of hydrogen. Blue ammonia production assumes 90% CO_2 capture rates of carbon capture and storage (CCS) technologies for unabated hydrogen production.

The emission of SO_2 and particle matter (PM) also decreases when co-firing ammonia. The reason for this is related to the lower amount of injected coal and the fact that NH_3 does not contain sulfur and forms less PM during combustion (ref. 1).

Studies pointed out that when co-firing ammonia at the rate of 20% in coal-fired power plants, it is possible to keep the NO_x emission from increasing significantly compared to the case of 100% coal combustion by keeping a stable flame and adjusting the two-stage combustion ratio and heat input (ref. 1, 3). The results from another study showed that under the condition of 20% co-firing, equivalent NO_x emission and unburnt carbon content are achieved, in comparison with those of pure coal combustion (ref. 4). This is probably caused by a combined effect of a high local equivalence ratio of NH_3/air and the prominent denigration effect of NH_3 in the vicinity of the location of the NH_3 downstream injection.
Higher rates of ammonia co-firing will lead to higher emission of NO_x. At 100% ammonia co-firing, the NO_x emission is estimated to increase about 30% compared to pure coal combustion (ref. 2). However, NO_x removal systems using selective catalytic reduction (SCR) technology, which converts nitrogen oxides into diatomic nitrogen and water, could effectively solve the problem.

Investment cost estimation

At the level of co-firing 20% ammonia in the pulverized coal-fired power plants, retrofit includes upgrading burners and additional balance of plant expenses to receive and store ammonia. Additional NO_x-reduction facilities are not necessary because NO_x emissions do not increase significantly with 20% co-firing ratio (see Effect on emission); these upgrades come at an estimated 11% premium in Capex (ref. 2)]. Considering using super-critical coal-fired power plants in Indonesia (investment cost of 1.40 MUSD/MW in 2020 – see Coal Power Plant – Steam Cycle/data sheet), the investment cost for co-firing 20% ammonia will be 0.15 MUSD/MW in 2020.

At higher ammonia co-firing ratio (e.g. 50% co-firing or 100% co-firing), storage tanks for ammonia would need to be bigger, as well as additional advanced equipment to capture NO_X emission. The boilers would require major upgrades or even replacement. At 100% firing of ammonia, the investment cost to retrofit coal-fired power plant is preliminary estimated at about 25% of CAPEX.

O&M cost: Since a new ammonia receiving device, pipes, tank and vaporizer, and modified burner are needed when co-firing ammonia, the O&M cost will tend to slightly increase from 5 – 10% depending on co-firing rate of ammonia (ref. 2).

Examples of current projects
Ammonia co-firing in coal-fired power plants is a relatively new technology that is still in the testing and development phase in many countries, including Japan and China. In Japan, ammonia co-firing has been tested at the Chugoku power plant, with a project to co-fire 1% ammonia in Unit 2 (120MW) starting in 2017 (ref. 7). More recently, Japan has also been testing co-firing of ammonia in Unit 4 (capacity 1000 MW) at the Hakinan power plant (3x700 + 2x1000 MW), with an ammonia mixing ratio of around 20% (ref. 8). In China, ammonia co-firing has been tested in a coal-fired power plant in Shandong province with a capacity of 40 MW and an ammonia mixing ratio of 35% (ref. 9).

The co-firing technology also are adopted by South Korea, India, and several countries of Southeast Asia like Indonesia and Malaysia (ref. 2). However, in those countries, the technology is still in development phase.

Ammonia cofiring Suralaya (ref 10)
Mitsubishi Heavy Industries, Ltd. (MHI), with support from its power solutions brand, Mitsubishi Power, has begun a feasibility study on the use of ammonia as fuel for power plants in Indonesia. The two proposals to carry out this study were recently adopted by Japan's Ministry of Economy, Trade and Industry (METI), to uncover and leverage the advanced technologies and expertise of Japanese companies to meet new global demands for infrastructure and contribute to global socioeconomic development. This is part of efforts to support energy decarbonization in the country through the Asia Energy Transition Initiative (AETI)(Note1).

These two studies will examine the feasibility of utilizing ammonia (Note2) at the Suralaya coal-fired power station and at an existing natural gas-fired power station in the country, derived from the abundant oil and natural gas produced in Indonesia, with the goal of establishing an integrated ammonia value chain encompassing production, transport, fuel consumption, and CO_2 storage.

The two proposals selected by METI for its "Feasibility Studies for the Overseas Deployment of High-quality Energy Infrastructure (Projects to Survey the Promotion of Overseas Infrastructure Development by Japanese Corporations)" are the "Survey of the Feasibility of Ammonia Mixed Fuel Combustion at the Suralaya Power Station in Indonesia and Evaluation of the Overall Value Chain" (the "Suralaya Project"), and the "Survey of the Feasibility of Retrofitting an Existing Natural Gas-fired Power Station in Indonesia to Introduce Power Generation Using Ammonia and the Establishment of a Value Chain" at an existing natural gas-fired power station (the "Existing Natural Gas-fired Power Station Project"). Both proposals will examine the potential reduction of CO_2 resulting from energy generation and its effects. The potential global impact, and high degree of utility and innovativeness of these feasibility studies, are regarded as significant to policies involving the Japanese government.

The main objective of the Suralaya Project is to calculate the economic efficiency of the envisioned process of transporting ammonia produced in Indonesia to the power station and consuming it as fuel for generating power. The project will be conducted jointly with Mitsubishi Corporation and Nippon Koei Co., Ltd., with operations expected to begin around 2030.
The main objective of the Existing Natural Gas-fired Power Station Project is to calculate the economic efficiency of transporting ammonia and hydrogen produced in Indonesia to a nearby existing natural gas-fired power station

as a fuel to generate power. The project will be conducted jointly with Tokyo Electric Power Services Co., Ltd. (TEPSCO), with operations expected to begin in the second half of this decade.

Both projects will examine the effectiveness of CO_2 reductions throughout the value chain, with MHI focusing primarily on the outcome of introducing ammonia power generation technologies. In addition, MHI plans to conduct a feasibility study based on institutional support measures such as financial support from the Japanese government, and decarbonization efforts and carbon pricing by Indonesia. Through the implementation of these projects, MHI hopes to contribute to the expansion of energy infrastructure exports from Japan.
Indonesia has announced a policy of deriving 23% of its power supply from renewable energy by 2025, and 28% by 2035. MHI and Mitsubishi Power will make a concerted effort as a corporate group, working in cooperation with Indonesia's state-owned power company group and the Bandung Institute of Technology (ITB), to support approaches that help the country achieve its targets.
Going forward, with encouragement from METI's adoption of these feasibility studies, MHI and Mitsubishi Power will contribute to further decarbonization in Indonesia, and provide momentum for the global deployment of the company's net zero energy transition policy through the projects.

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Data sheet

The following pages contain the data sheets of the technologies. All costs are stated in U.S. dollars (USD), price year 2022. The uncertainty is related to the specific parameters and cannot be read vertically – meaning a product with e.g., lower efficiency does not have a lower price.

Technology

Technology	Coal Power Plant – Steam Cycle – co-firing 20% ammonia								
	2023	2030	2050	Uncertainty (2030)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MW)	600	600	600	300	800	300	800		
Electricity efficiency. net (%). name plate	-1	-1	-1	0	-2	0	-2	A,B	1
Electricity efficiency. net (%). annual average	-1	-1	-1	0	-2	0	-2	A,B	1
Forced outage (%)	0	0	0	0	+1	0	+1	A	
Planned outage (weeks per year)	0	0	0	0	0	0	0	A	
Technical lifetime (years)									
Construction time (years)									
Space requirement (1000m2/MW)									
Ramping configurations									
Ramping (% per minute)	0	0	0	0	0	0	0	A	
Minimum load (% of full load)	0	0	0	0	0	0	0	A	
Warm start-up time (hours)	0	0	0	0	0	0	0	A	
Cold start-up time (hours)	0	0	0	0	0	0	0	A	
Environment									
PM2.5 (% compared to 100% coal)	-20%	-20%	-20%	-10%	-20%	-10%	-20%	A	1
SO2 (% compared to 100% coal)	-20%	-20%	-20%	-10%	-20%	-10%	-20%	A	1
NO_X (% compared to 100% coal)	+5%	+5%	+5%	0%	+10%	0%	+10%	A	1,2,3,4
Financial data									
Nominal investment (M$/MWe)	+0.15	+0.15	+0.14	+0.11	+0.19	+0.11	+0.18	A,C,D	2
- of which equipment	-	-	-	-	-	-	-		
- of which installation	-	-	-	-	-	-	-		
Fixed O&M (% compared to 100% coal)	+5%	+5%	+5%	+3%	+8%	+3%	+8%	A	2
Variable O&M (% compared to 100% coal)	+5%	+5%	+5%	+3%	+8%	+3%	+8%	A	2

Technology	Coal Power Plant – Steam Cycle – co-firing 100% ammonia							
	2030	2050	Uncertainty (2030)		Uncertainty (2050)		Note	Ref
Energy/technical data			Lower	Upper	Lower	Upper		
Generating capacity for one unit (MW)	600	600	300	800	300	800		
Electricity efficiency. net (%). name plate	-2	-2	-1	-3	-1	-3	A,B	1
Electricity efficiency. net (%). annual average	-2	-2	-1	-3	-1	-3	A,B	1
Forced outage (%)	0	0	0	+1	0	+1	A	
Planned outage (weeks per year)	0	0	0	0	0	0	A	
Technical lifetime (years)								
Construction time (years)								
Space requirement (1000m2/MW)								
Ramping configuration								
Ramping (% per minute)	0	0	0	0	0	0	A	
Minimum load (% of full load)	0	0	0	0	0	0	A	
Warm start-up time (hours)	0	0	0	0	0	0	A	
Cold start-up time (hours)	0	0	0	0	0	0	A	
Environment								
PM2.5 (% compared to 100% coal)	-100%	-100%	-70%	-100%	-70%	-100%	A	1
SO2 (% compared to 100% coal)	-100%	-100%	-70%	-100%	-70%	-100%	A	1
NO_X (% compared to 100% coal)	+30%	+30%	+20%	+50%	+20%	+50%	A	1,2,3,4
Financial data								
Nominal investment (M$/MWe)	+0.34	+0.33	+0.26	+0.44	+0.25	+0.41	A,C,D	2
- of which equipment	-	-	-	-	-	-		
- of which installation	-	-	-	-	-	-		
Fixed O&M (% compared to 100% coal)	+10%	+10%	+5%	+15%	+5%	+15%	A	2
Variable O&M (% compared to 100% coal)	+10%	+10%	+5%	+15%	+5%	+15%	A	2

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Notes:

A Value depends on the original plant. Value indicates the estimated change from the original value (unit is the same as the parameter).

B Typically, the electricity efficiency will be 1-2 % point lower than that of the plant prior to conversion.

C The nominal investment assumes that exclude investment for a general lifetime extension campaign

D The investment cost includes, modifying existing coal plants for ammonia co-firing requires boiler modifications and investment in additional facilities like ammonia tanks and vaporizers. In general, the retrofits include (ref. 2):Modified burner; New ammonia receiving device, pipe, tank and vaporizer; Additional NOx removal device. The cost of improving pipelines outside the plant-land plot is not included.

9. Retrofit of Coal Plants - Direct Co-Firing of Biomass in Existing Power Plants

Brief technology description

Co-firing biomass and coal in power generation refers to a method of using biomass as a replacement for some of the coal used in thermal power plants. The potential advantages of a power plant that uses co-firing biomass and coal over a traditional coal-fired power plant include a significant reduction in CO_2, NO_x, and SO_x emissions (ref. 1). However, due to the lower heating value of biomass fuel compared to coal, the electricity efficiency of the co-firing system is lower than a 100% coal-burning system.

There are three main technologies: direct co-firing, indirect co-firing, and parallel co-firing (ref. 2).

- Direct co-firing involves the simultaneous combustion of biomass and coal in the same furnace. This means that the fuel is simultaneously fed into the same combustion chamber and burned together.
- Indirect co-firing, on the other hand, involves the gasification of the biomass in a separate chamber, the gasification gas is then let into the combustion chamber of the coal boiler and combusted.
- Parallel co-firing involves the use of a separate combustion chamber or boiler solely dedicated to the combustion of biomass. The steam generated from the combustion of biomass is then used in the conjunction with steam generated from the combustion of coal to generate electricity.

The three types are illustrated in the figure below.

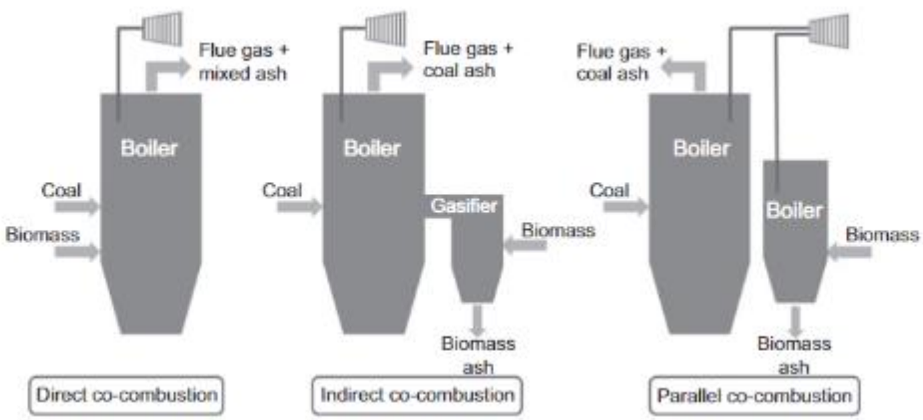

Figure 1: Schematic presentation of co-firing technology options (ref. 4).

Each of the three technologies has its own advantages and limitations in terms of cost, efficiency, feasibility, and environmental impact. Direct co-firing is the simplest, cheapest and most widespread approach of the three (ref. 10), however it requires high-quality, low moisture and low ash biomass fuel. Indirect co-firing requires more complex equipment, but it allows for more flexibility in terms of fuel types, including lower quality fuels. Finally, parallel co-firing allows for the combustion of a wide range of biomass fuel types, however it's the most complex and costly, and will require most extensive modification to the power plants. In this sub-chapter, we will focus on **direct co-firing technology**.

With pulverized coal technology (PC), the most suitable biomass for co-firing is wood pellets, which is a fuel with the most similar characteristics to coal, meaning that the same boiler can be used. Pellets is a homogeneous and pre-dried fuel of various standardized qualities, produced from biomass material such as wood, wood industry residues, other energy crops or residues of agricultural production, etc., typically produced abroad and transported to the power plants in large vessels. The pellets have controlled water content, typically below 10% (ref. 1).

The simplest is to pre-mix the biomass with the coal and feed the mixed fuel into the bunkers, processing the fuel through existing coal milling and firing equipment. This approach is possible for cofiring up to 10% (energy basis) with negligible additional investment costs. This limitation is related to the ability of coal mills to co-mill biomass materials. Problems may arise as most mills pulverizing coal depend on brittle fracture of the coal particles whereas biomass materials, which are generally fibrous, do not mill by this mechanism. To increase the share of biomass co-firing, the second method is the separate handling, metering and comminution of the biofuel which is then injected into the pulverized coal flow upstream of the burners or at the burners. The third method is combusted in a number of dedicated burners. In general, when increasing to firing 100% biomass, the below elements are expected to be added, replaced, or refurbished:

- New storage silos and transport systems for the pellets
- Coal mills, to be modified and with extended capacity due to lower calorific value
- Larger fans for pneumatic transport systems
- New burners
- Boiler modifications, e.g. soot blowers to avoid deposits

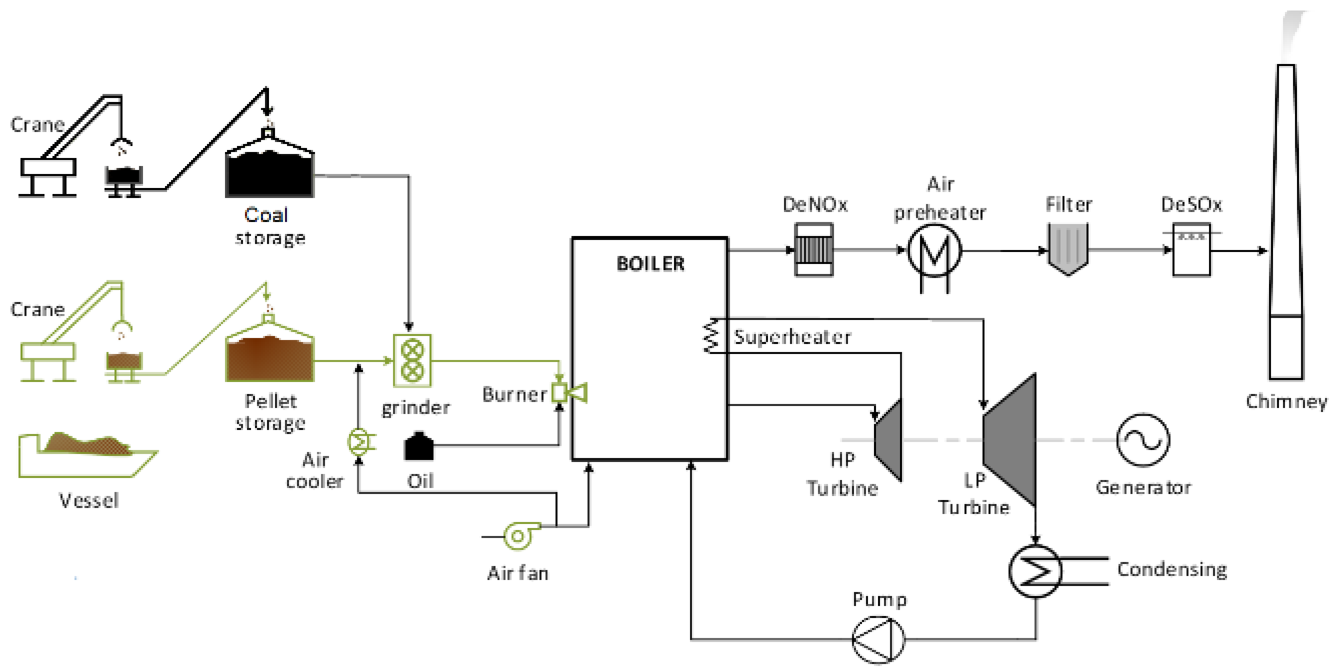

Figure 2. Sketch of a pulverized coal plant co-firing with wood pellets. The green elements indicate the equipment that needs to be added, replaced or refurbished.

Wood chips are a less homogeneous fuel than pellets, with large variations in quality and size. Its water content is high, typically from 20% and up to more than 50%, and it may as well contain fractions of soil. Therefore, in case of using wood chip for co-firing in pulverized coal plant, it is needed to install a plant for processing the chips into dry and fine-grained matter, i.e. comparable to the fuel obtained by grinding wood pellets, this will increase the retrofit cost of co-firing.

The circulating fluidized bed (CFB) coal-fired plant can use wood pellet, wood chip and other biomass for co-firing. Clearly, stoker and FBC boilers, which are designed to fully fire biomass, are much more suited for co-firing higher percentages of biomass than pulverized coal boilers. The CFB boiler can co-fire with 20% biomass for a low extra cost. The figure below shows a principal sketch of the CFB plant and which elements are expected to be added, replaced or refurbished to run on 100% biomass.

- New storage and transport systems for the wood chips
- Larger fans for pneumatic transport systems
- At high share of biomass, the steam pressure is often lower, therefore, the high-pressure turbine may need to be upgraded (Otherwise, the pressure drops over the high-pressure turbine and the steam will condensate. In this case, the low-pressure turbine will get steam that is too "wet" which will reduce the life time).
- Upgrading the flue gas system if needed.

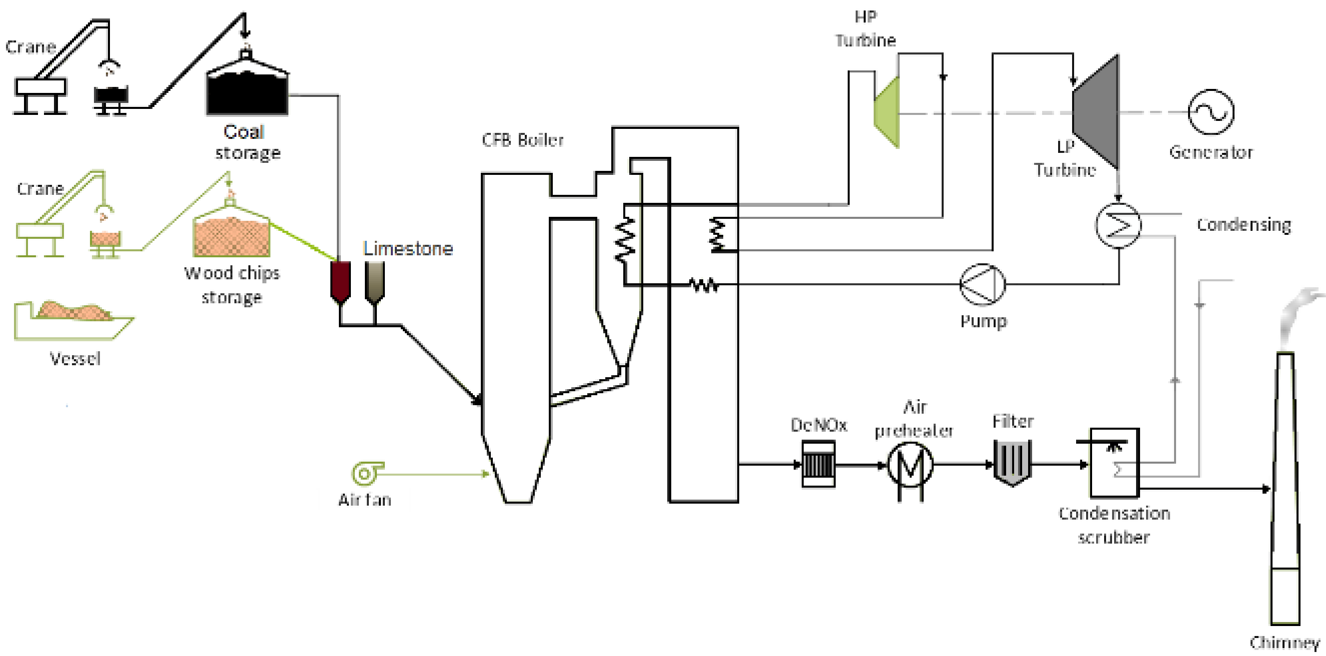

Figure 3. Sketch of a CFB coal plant co-firing with wood chip. The green elements indicate the equipment that needs to be added, replaced or refurbished.

The optimal mixing ratio of biomass fuel is determined based on factors such as cost and the operating requirements of each power plant. Currently, most power plants using co-firing technology of biomass and coal are applying mixing ratios of biomass fuel ranging from 5% to 10% (ref. 2). In terms of technical feasibility, this ratio can reach over 50%, and may even be up to 100% depending on the conditions of the power plant.

The current trend in co-firing biomass and coal technology is to increase the biomass ratio in commercial projects and to eventually move towards using only biomass fuel as a replacement for coal. In some European countries like Denmark and the UK, there are power plants that started with mixing ratios of 3% to 10%, and some of them have already switched to using 100% biomass1 fuel (ref. 8). In Japan, there are currently some power plants that blend biomass with a ratio from 15% to 30% in existing coal-fired power plants, with plans to increase the biomass ratio to 50% to 100% after some plants undergo renovation from 2023 to 2035. In Vietnam, Ninh Binh coal-fired plant of the pulverized coal type has tested co-firing with wood pellets at the highest share of biomass of 43% in 2020 (ref. 11).

Table 1: Example of co-combustion ratio of biomass in coal-fired power plants (ref. 3)

Power Plant/Commissioning Time.	Capacity of Coal-Fired Unit	Coupling Form	Biomass Fuel	Co-Combustion Ratio of Heat	Technical Characteristics
Shiliquan Power Plant/2005	400t/h high temperature and high pressure boiler	Direct co-firing	Wheat-straw, corn stalk	18.6% (Design), 5%~8% (Reality)	Adopt the independent burning system of BWE company in Denmark to achieve co-combustion, and the fuel entering the boiler needs to be pretreated.
Baoji No.2 Power Generation Co., Ltd/2010	300 MW boiler	Direct co-firing	Straw, molding biomass	6.76%~21.90%	Through a set of pulverizing system, biomass fuel is burned separately
British Tibury power plant/2004	712 MW	Direct co-firing	Forest tree, wood pellet	~100%	Using biomass to break in biomass burner
British Fiddlers Ferry power plant/1995	4*500 MW	Direct co-firing	Pressed waste wood pellet fuel, olive core and other biomass	20%	After grinding, biomass particles are directly sent to the boiler for combustion

<u>Fuel delivery, storage and handling:</u> Biomass has a much lower bulk density, it is generally moist, strongly hydrophilic and non-friable. The lower heating values and much lower bulk densities mean that the overall fuel densities of biomass in MJ/m^3 could be one tenth that of coal. Hence, co-firing biomass at 10% of thermal input requires comparable flows of biomass and coal. Co-firing higher percentages of biomass would require much higher flows of biomass than coal. Hence, the on-site delivery, storage and fuel handling demands of biomass are disproportionately high compared with coal. These issues will be particularly apparent when co-firing high biomass ratios. It may also be necessary to add extra flexibility in fuel storage and handling facilities to utilize multiple sources of biomass. The handling and flow properties of biomass are usually more problematical than coal due to the fuel size variation and high fibre and oversized particle content.

<u>Slagging and fouling:</u> Biomass fuels can contain a higher proportion of alkaline species compared with coal though the total ash content must also be considered. The constituents of ash such as alkali metals, phosphorus, chlorine, silicon, aluminum and calcium affect ash melting behavior. Alkaline metals readily vaporize during combustion. A key reaction that needs to be considered is the release of volatile species, such as alkali metals and phosphate compounds and their subsequent deposition on boiler surfaces and on surfaces of ash particles and deposits. The major proportion of inorganic materials in biomass is in the form of salts or bound in organic matter, whereas in coal they are bound in silicates which are more stable.

<u>Corrosion and erosion</u>: The majority of biomass fuels tend to be relatively rich in alkali metals, especially potassium and in some cases phosphates. They also have relatively low sulfur contents. Moreover, some types of biomass contain relatively high chlorine contents, up to 1% which is released as HCl in the boiler flue gas and can lead to the enrichment of chloride at the metal/oxide/ash deposit interface. Biomass ash deposits tend to have relatively high potassium contents and relatively high chloride to sulphate ratios. This can have a significant impact on corrosion, particularly at high metal temperatures on superheater surfaces.

Effect on boiler efficiency and operation characteristic

Compared to coal and other fossil fuels, biomass fuel typically has a lower heating value and a higher cost. Biomass co-firing could lead to the reduction of furnace's efficiency. Blending biomass with bituminous and lignite coal at a ratio of 30%, the efficiency of the plant can decrease from 35.2% to 34.6% and from 34.1% to 33.8% respectively (ref. 7).

The regulation abilities will in most cases not change much, in case existing boilers of coal fired plants are co-firing with biomass.

Investment cost estimation
The investment cost of co-firing biomass in coal power plant largely depends on the plant capacity and service (i.e. power generation only or combined heat and power), as well as the type of the biomass fuel to be used, and the quality of the existing boiler.

At 20% biomass co-firing on energy basis, PC boiler need to install new biomass storage and transport systems, retrofit burner and modified coal mill, or a new dedicated mill come with a retrofit cost of about 10% base Capex. While in CFB boiler, only biomass storage and transport systems are needed with low retrofit cost of about 3% Capex (ref. 1,11,12).

Pulverized coal plants 100% biomass firing will need larger biomass storage and transport systems. Furthermore, a larger dedicated mill and a new burner is needed. There is a need for modifying the reheater and superheater for larger spacing, using more corrosion resistant high alloy materials, increasing soot blowing and lowering the final temperature to reduce risk of the ash depositions and excessive slag. This comes with the higher retrofit cost of about 25% base Capex. With CFB boiler, the retrofit includes larger biomass storage and transport systems, larger fan, and other related facilities. This comes with an investment cost of about 15% of Capex (ref. 1,11,12).

O&M cost: Since there are modifications of some components when co-firing biomass (fuel delivery and storage, mill or burner), the O&M cost will tend to slightly increase, from 3 – 5% depending on co-firing rate of biomass.

Environment
Effect on emission
SO_2 emissions decrease, often in proportion to the amount of biomass used, as most types of biomasses contain less sulfur than coal. Further reductions are sometimes observed as biomass ash frequently contains higher levels of alkali and alkaline earth compounds than coal and can retain a greater fraction of sulfur in the ash. The proportion of sulfur retained in the ash typically increases from 10% in coal to 50% for pure biomass.

NO_x emissions when co-firing biomass are more difficult to predict and may increase, decrease, or remain the same as compared to coal firing depending on the type of biomass, firing conditions and operating conditions. Some biomass fuels, such as wood fuels, have lower nitrogen contents than coal, other fuels such as alfalfa stalks and rice hulls can contain higher nitrogen contents than typical coals. However, NO_x emissions are mainly formed by the N_2 in the combustion air and the amount are mainly determined by the pressure and temperature in the combustion zone.

In the studies from (ref. 5,6), it was estimated that NO_x and SO_x emissions can be reduced by approximately 10% compared to burning 100% coal, with a mixing ratio of around 16% to 20% biomass.

Examples of current projects
British Tibury power stations B began converting to burn 100% biomass from May 2011 with direct co-firing technology, the conversion would allow 750 MW of electricity to be generated from burning wood pellets imported from a pelleting plant in Georgia, USA, and other sources from Europe by the winter of 2011. This conversion made the station the biggest biomass generating site in the world (ref. 19).

In Vietnam, Ninh Binh Thermal Power Plant has been in operation since 1974 and consists of four medium-voltage generating with a total design capacity of 100 MW (4 x 25 MW). The plant has conducted 2 trials of biomass co-firing with the main purpose to reduce SO_x emissions in 2020. The first time in October 2020, the plant purchased 30 tons of biomass in pellet form produced from forest by-products and mixed with coal at the depot at the rates of 15% and 20%. Biomass was supplied to the coal crushing system and burned in the boiler. The second time in November 2020, the plant co-fired about 50 tons of biomass with coal through 3-level wind nozzles into the boiler with the rates: 18%, 28% and 43%. The results showed that SO_2 emission concentration decreased significantly from 408.4 mg/Nm^3 at 0% biomass to 382.52 mg/Nm^3 at 18%, 296.06 mg/Nm^3 at 28% and 145.67 mg/Nm^3 at 43% (ref. 20).

PLTU Air Anyir Bangka (ref 14)

Co-firing at the 2×30 MW capacity PLTU uses woodchip biomass with local energy sources of wood from production forests on the island of Bangka. Currently, the woodchips used come from rubber trees in the Bangka district area, with a heating value of ±4000 kcal/kg. During the co-firing journey, PLTU Air Anyir Bangka has tested woodchip co-firing with a coal mixture on April 19–20, 2021. The woodchip mixture used was 5%, or 36 tons, of biomass at a load of 25 MW gross. The results of this 5% co-firing combustion can reduce NOx emissions by 15 ppm and SOx emissions by 65.8 ppm.

By implementing 5% cofiring, the PLTU, with an average production of 354,391 MWh per year, has the potential to consume 18,297 tons of woodchip biomass per year, or 1,500 tons per month. As of September 1, 2022, the total green energy production had reached 140.62 GWh. With the increasing commercialization of co-firing at the Air Anyir PLTU, PNP is optimistic that total green energy production by the end of 2022 can increase.

With an average annual production of 354,391 MWh, the PLTU has the ability to utilize 18,297 tons of woodchip biomass per year, or 1,500 tons per month, by applying 5% cofiring. Total green energy production had reached 140.62 GWh as of September 1, 2022. PNP is optimistic that total green energy production will increase by the end of 2022 due to the rising commercialization of co-firing at the Air Anyir PLTU.

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Data sheet

The following pages contain the data sheets of the technologies. All costs are stated in U.S. dollars (USD), price year 2022. The uncertainty is related to the specific parameters and cannot be read vertically – meaning a product with e.g., lower efficiency does not have a lower price.

Technology

Technology	Coal Power Plant – Steam Cycle – co-firing 20% biomass (wood pellets)								
	2023	2030	2050	Uncertainty (2030)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MW)	600	600	600	300	800	300	800		
Electricity efficiency. net (%). name plate	-1	-1	-1	0	-2	0	-2	A,B	1,3,4
Electricity efficiency. net (%). annual average	-1	-1	-1	0	-2	0	-2	A,B	1,3,4
Forced outage (%)	0	0	0	0	1	0	1	A	1,3,4
Planned outage (weeks per year)	0	0	0	0	0	0	0	A	1,3,4
Technical lifetime (years)									
Construction time (years)									
Space requirement (1000m2/MW)								A,C	1,3,4
Ramping configurations									
Ramping (% per minute)	0	0	0	0	0	0	0	A	1,3,4
Minimum load (% of full load)	0	0	0	0	0	0	0	A	1,3,4
Warm start-up time (hours)	0	0	0	0	0	0	0	A	1,3,4
Cold start-up time (hours)	0	0	0	0	0	0	0	A	1,3,4
Environment									
PM2.5 (% compared to 100% coal)	-10%	-10%	-10%	-5%	-20%	-5%	-20%	A	1,2,3,4
SO2 (% compared to 100% coal)	-10%	-10%	-10%	-5%	-20%	-5%	-20%	A	1,2,3,4
NO_X (% compared to 100% coal)	-5%	-5%	-5%	0%	-10%	0%	-10%	A	1,2,3,4
Financial data									
Nominal investment (M$/MWe)	+0.16	+0.16	+0.15	+0.12	+0.20	+0.11	+0.19	A,D	1,3,4
- of which equipment	-	-	-	-	-	-	-		
- of which installation	-	-	-	-	-	-	-		
Fixed O&M (% compared to 100% coal)	3%	3%	3%	1%	5%	1%	5%	A	1,3,4
Variable O&M (% compared to 100% coal)	3%	3%	3%	1%	5%	1%	5%	A	1,3,4

Technology	Coal Power Plant – Steam Cycle – co-firing 100% biomass (wood pellets)							
	2030	2050	Uncertainty (2030)		Uncertainty (2050)		Note	Ref
Energy/technical data			Lower	Upper	Lower	Upper		
Generating capacity for one unit (MW)	600	600	300	800	300	800		
Electricity efficiency. net (%). name plate	-2	-2	-1	-3	-1	-3	A,B	1,3,4
Electricity efficiency. net (%). annual average	-2	-2	-1	-3	-1	-3	A,B	1,3,4
Forced outage (%)	0	0	0	1	0	1	A	1,3,4
Planned outage (weeks per year)	0	0	0	0	0	0	A	1,3,4
Technical lifetime (years)								
Construction time (years)								
Space requirement (1000m2/MW)							A,C	1,3,4
Ramping configurations								
Ramping (% per minute)	0	0	0	0	0	0	A	1,3,4
Minimum load (% of full load)	0	0	0	0	0	0	A	1,3,4
Warm start-up time (hours)	0	0	0	0	0	0	A	1,3,4
Cold start-up time (hours)	0	0	0	0	0	0	A	1,3,4
Environment								
PM2.5 (% compared to 100% coal)	-70%	-70%	-50%	-90%	-50%	-90%	A	1,2,3,4
SO2 (% compared to 100% coal)	-70%	-70%	-50%	-90%	-50%	-90%	A	1,2,3,4
NO_X (% compared to 100% coal)	-30%	-30%	-5%	-40%	-5%	-40%	A	1,2,3,4
Financial data								
Nominal investment (M$/MWe)	+0.36	+0.36	+0.28	+0.46	+0.26	+0.44	A,D	1,3,4
- of which equipment	-	-	-	-	-	-		
- of which installation	-	-	-	-	-	-		
Fixed O&M (% compared to 100% coal)	5%	5%	3%	10%	3%	10%	A	1,3,4
Variable O&M (% compared to 100% coal)	5%	5%	3%	10%	3%	10%	A	1,3,4

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Notes:

A Value depends on the original plant. Value indicates the estimated change from the original value (unit is the same as the paramter).

B Typically the electricity efficiency will be 1-2 % point lower than that of the plant prior to conversion.

C Some additional under roof space (or silos) will be required for storage of pellets compared to coal (estimated 50%-100% extra m3 storage). But not more floor space (m2).

D The nominal investment is excluding investment for a general life time extension campaign

10. Lifetime Extension of Existing Coal Plants

Brief technology description

Lifetime extension of existing large coal fired power plants offers a relatively quick and easy solution to keep existing capacity in operation, since the costs are typically several times lower than investments in new capacity. When a plant has been in operation for 30-35 years or more, the reliability of its components and systems will likely decrease leading to reduced availability and/or increased O&M costs. Therefore, based on experience, it will usually be necessary and beneficial to carry out a larger package of work that addresses repairs, renovation, and replacement of selected components and systems depending on their actual condition. Improvement of environmental performance may be required, e.g. by improving the flue gas cleaning performance.

This 'Lifetime Extension' (LTE) is done with the purpose of restoring the plant to get close to its original conditions in terms of availability, efficiency, and O&M costs. Though, the exact scope and extent of such a campaign shall be tailored to the actual plant in question and will depend on its design, previous records of operation, earlier major works carried out, etc. Furthermore, the expected/desired future operation of the plant must be considered. Therefore, the lifetime extension of a power plant is not a simple decision but involves complex economic and technical factors (ref. 5).

In this technology catalogue it is assumed that the lifetime extension:

- Takes place after approx. 30 years of normal operation;
- During such operation, the maintenance of the plant has been carried out as planned;
- The maintenance has enabled the plant to be operated with the availability rate close to that of the original new plant, and within the originally expected O&M budget;
- Extended lifetime of approx. 20 years

Aging limit mechanisms: The life extension of a power plant usually requires replacing the existing components if they reach their technical lifetime. The aging limit can vary significantly, depending on the component design, operating conditions, and regular maintenance. In a coal power plant, the aging limit of component depends on many mechanisms including creep, fatigue, corrosion, erosion, spallation and obsolescence, each of which are explained below (ref. 2).

The typical failure mechanisms for major components in a power plant are shown in the following table.

Typical components failure mechanisms (ref. 2)

	Components	Creep	Low Cycle Fatigue	High Cycle Fatigue	Corrosion	Erosion	Concrete Spallation	Obsolescence
Boiler	HT components, headers, main steam pipework, steam chests HT bolts.	X HT Pressure parts	X Drums and Headers		X Internal tubing	X Parts in air/ gas path	X Support structures	
Steam Turbine	HP and IP rotors and cylinders, casings, valves, steam chests	X HT pressure parts	X	X	X Parts exposed to air/moisture/ heat	X LP blades		
Balance of Plant	Airheaters, ID Fans, FD Fans, PA fans, Milling Plant		X Fans, Mills, Airheaters		X ID Fans Mills, Airheaters	X	X Mill Foundations	
Cooling and Feedwater Systems	Condenser, air ejectors, pumps, motors, valves, cooling towers feedwater heaters.		X Pumps and Motors	X Pumps and Motors	X	X		
Electrical	Generators , transformers, switchyard , cabling breakers.		X	X	X			
Civils	Roofs, Walls, Steel Structures, Foundations				X	X	X	
Other	Instrumentation, Digital Control systems, auxiliary control systems							X

In connection with the LTE, the plant will be out of operation for a period of typically 6-9 months.

The LTE will involve considerable project costs for planning and management since it requires establishing a project organization for engineering, purchase, construction management, test, and commissioning.
The works involved with a LTE of an existing coal fired plant could be as follows, however depending widely on the actual scope of the project (ref. 5).

Main elements:

- Revision of electrical systems
- Instrumentation and control systems replacement
- Pulverizers upgrade or replacement (fuel supply and disposal)
- Boiler upgrade
- Turbine refurbishment (possibly generator refurbishment)
- Water systems (heat exchanges for condensers and district heating)
- Buildings
- Flue gas cleaning.

In order to extend the lifetime of coal-fired power plants, the components in the table below need to be periodically replaced, upgraded or refurbishment.

Main component life cycle for coal power plant (ref. 2)

Area	Inspection	Activity	Frequency (year)	Year	30 31	32 33	34 35	36 37	38 39	40 41	42 43	44 45	46 47	48 49
Boiler	Major overhaul		4			x		x		x		x		x
	Ineter overhaul		2		x		x		x		x		x	
	HT Headers	Replace	28											
	Main steam pipework	Replace	40							x				
Stem turbine	Major overhaul		12					x						x
	Ineter overhaul		4			x				x		x		x
	HP & IP rotors	Refurb	16			x								x
	LP rotors	Refurb	28											
	Steam chests	Replace	28											
	Generator	Refurb	16			x								x
Feed water system	Feed heaters	Refurb	30		x									
	Condenser waterbox	Refurb	30		x									
Electrical	Generator	Refurb	20							x				
	Transformers	Renew	30		x									
	Motors	Refurb	10		x					x				
Control & Inst	DCS	Upgrade	10		x					x				
	Man machine interface	Upgrade	10		x					x				
Coal & Ash plant	Coal plant	Refurb	12					x						x
	Ash plant	Refurb	12					x						x
	Precipitors	Refurb	12					x						x
Civil	Exposed steelwork	Repaint	25											
	Roof & cladding	Repair	25											

For a typical coal power plant, the major overhaul frequency is shown in the following table.

Major overhaul frequency for coal power plant [ref 2]

Plant Area	Type	Frequency (Years)	Duration (weeks)
Boiler	Major Overhaul	4	10 weeks
	Intermediate	2	4 weeks
Steam Turbine	Major Overhaul	12*	10 weeks
	Intermediate	4*	4 weeks

Lifetime extension of existing plants is also relevant when converting to other fuels e.g. biomass as discussed in the section of co-firing of power plants.

Effect on efficiency and operation characteristic

Lifetime extension of coal-fired plants aims to maintain the performance of the existing plants, so the efficiency will remain the same or slightly lower than the original one (ref. 2).

The regulation abilities of coal fired power plants, e.g. start-up time and ramp rates may improve in connection with LTE due to implementation of better control systems (ref. 2). This effect is, however, not possible to be quantified on a general level. In general, start-up times and -costs are not considered to change due to LTE.

Investment cost estimation, overview

During an international study (ref. 2), the cost of lifetime extension for 20 years from the year 30th to 50th of operations for a typical 1000 MW coal-fired power plants were calculated. The results showed that the total cost is estimated at 257 million dollars, corresponding to **0.26 M$/MW** (as shown in the table below):

Component cost of lifetime extension for coal-fired power plant (ref. 2)

Area	Inspection	Activity	Frequency (year)	Cost per unit (M$)	30 31	32 33	34 35	36 37	38 39	40 41	42 43	44 45	46 47	48 49
Boiler	Major overhaul		4	20.1		1		1		1		1		1
	Ineter overhaul		2	2.31	1		1		1		1		1	
	HT Headers	Replace	28	1.54										
	Main steam pipework	Replace	40	12.32						1				
Stem turbine	Major overhaul		12	12.32				1						1
	Ineter overhaul		4	1.54		1				1		1		1
	HP & IP rotors	Refurb	16	12.32		1								1
	LP rotors	Refurb	28	9.24										
	Steam chests	Replace	28	3.08										
	Generator	Refurb	16	3.08		1								1
Feed water system	Feed heaters	Refurb	30	3.08	1									
	Condenser waterbox	Refurb	30	6.16	1									
Electrical	Generator	Refurb	20	7.7						1				
	Transformers	Renew	30	4.62	1									
	Motors	Refurb	10	3.08	1					1				
Control & Inst	DCS	Upgrade	10	3.08	1					1				
	Man machine interface	Upgrade	10	3.08	1					1				
Coal & Ash plant	Coal plant	Refurb	12	7.7				1						1
	Ash plant	Refurb	12	3.08				1						1
	Precipitors	Refurb	12	4.62				1						1
Civil	Exposed steelwork	Repaint	25	3.08										
	Roof & cladding	Repair	25	1.54										
	Yearly cost (M$)				**25.4**	**37.0**	**2.3**	**47.8**	**2.3**	**50.9**	**2.3**	**21.6**	**2.3**	**64.8**
	Total cost (M$)				**256.8**									

The Danish Technology Catalogue also mentions extending the life of coal-fired power plants for 15-20 years with the purpose of restoring the plant to come close to its original conditions. The total cost for lifetime extension given was **0.26 M$/MW**.

In Vietnam, Ninh Binh TPP have not completed the lifetime extension of 20 years and the cost for the upgrading/replacing was not provided. The catalogue has a rough estimate for the cost of lifetime extension for whole 20-year period of about 620 billion Dong- corresponding to **0.27 M$/MW**, based on estimated cost for each component.

The O&M cost also aims to be maintained within the originally expected O&M budget. However, the average fixed O&M cost may increase slightly for the extension period compared with the original lifetime to accommodate the necessary reinvestments during the extended lifetime.

Investment costs [$MUSD_{2022}$/MW]		2023	2030	2050
Catalogues	**New Catalogue (2023)**	**0.28**	**0.28**	**0.28**
International data	Danish technology catalogue	0.28	0.28	0.28
	Vietnam Ninh Binh TPP	0.29	0.29	0.39
	Vietnam Technology Catalogue (2023)	0.28	0.28	0.28
Projection	Development curve – cost trend [%]	100%	100%	100%

Environment

Effect on emissions

The lifetime extension is not in itself expected to change the environmental performance characteristics beyond the maximum allowed emission values at the time of LTE, that probably are more stringent than the original requirements. If advantageous or required, such further improvements may be implemented in connection with LTE campaign.

Research and development perspectives

It is not anticipated that there will be a considerable further development in the technology relevant for lifetime extension of large coal fired power plants. However, with the large number of coal power plants running world-wide, it is expected that LTE methods will generally improve.

Examples of current projects

In Vietnam, Ninh Binh Thermal Power Plant has been in operation since 1974 and consists of four medium-voltage generating with a total design capacity of 100 MW (4 x 25 MW). Traditional coal-fired (PC) steam boilers naturally circulate steam. After 48 years of commercial operation, the plant generates about 28.84 billion kWh of electricity to the national grid.

Boiler System: Updating UD nozzles (high density) in boilers have significantly improved boiler characteristics, increased efficiency by 1 ÷ 2%, no slag formation, extended furnace operating cycle, and reduced the percentage of residual carbon in the ash, reducing the concentration of NOx.

Turbine: The turbines No. 1, 2, and 3 after being replaced operate reliably, ensuring design capacity and efficiency from 30 ÷ 32%. Currently, turbine No. 4 has a long operating time, the impellers have corrosion, pitting affecting reliability and low efficiency 27% ÷ 28%, expected to be replaced in 2023.

No.	Specifications	Unit	Turbine 1	Turbine 2	Turbine 3	Turbine 4
1	Year of renewal	Year	2019	2018	2016	
2	Rated capacity	MW	25	25	27	25
3	Heat rate	kJ/kWh	11.243,9	11.207,9	11.246	13.100
4	Efficiency	%	32,02	32,12	32,01	27,48

Generator: The generators have been restored with new insulation and the excitation system has been replaced with a Unitrol 6080, which is stable and reliable. In 2007, replacing fuel oil used for starting the furnace and burning it with DO oil with the aim of reducing the amount of ash, SOX, NOX in production technology, and overcoming exhaust gas pollution. Replaced Siemens digital protection relay system for 04 groups of generator-transformer and electrical resistance in 2009 and 2010.

Transformers: The main transformers have been replaced: T1, T3 transformers in the years 2000 and 2013, transformers T2, T4 with large losses affecting the increase of self-consumption electricity, are expected to be replaced in the period of 2023-2025. 110 kV circuit breaker was replaced with SF6-110kV circuit breaker and 35 kV circuit breaker with vacuum circuit breaker cabinet manufactured by Siemens Germany in 2005.

Emissions treatment system: Upgrading ESP control system with EPIC-III and SIR4 of Alstom (2013-2014). The power plant does not have FGD, SCR systems to treat SO_x and NO_x emissions (expected to be installed from 2023-2026). Through the automatic online emission monitoring system, the concentrations of CO, SO2 and NOx all meet the permissible standards for emissions QCVN 22:2009.

Upgrading coal storage and supply system: install air cannon, renew water pump and cooled fan (2020-2021).

References

1. IEA, "Generating unit annual capital and life extension cost analysis," 2019.
2. Parsons Brinckerhoff, "Coal and Gas Assumptions," 2014. [Online]. Available: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/315717/coal_and_gas_assumptions.PDF.
3. S. Thomas, "Power-plant life extension," *Energy*, vol. 13, no. 10, pp. 767–786, 1988, doi: https://doi.org/10.1016/0360-5442(88)90060-6.
4. EIA, "Generating Unit Annual Capital and Life Extension Costs Analysis", 2019.
5. Electricity Generation Costs, Department of Energy and Climate Change (UK), Dec 2013 [Online]. Available: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/269888/131217_Electricity_Generation_costs_report_December_2013_Final.pdf
6. Danish Energy Agency and Energinet, "Technology Data - Energy Plants for Electricity and District heating generation", 2016.
7. EPRI, Generic guidelines for the life extension of fossil fuel power plants, 1986

Data sheets

The following pages contain the data sheets of the technologies. All costs are stated in U.S. dollars (USD), price year 2022. The uncertainty is related to the specific parameters and cannot be read vertically – meaning a product with e.g., lower efficiency does not have a lower price.

Technology

Technology	Lifetime extension of coal power plant								
	2023	2030	2050	Uncertainty (2030)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MW)	600	600	600	300	800	300	800		
Electricity efficiency. net (%-point). name plate	-1	-1	-1	0	-3	0	-3	A	1,3,4
Electricity efficiency. net (%). annual average	-1	-1	-1	0	-3	0	-3	A	1,3,4
Forced outage (%-point)	0	0	0	0	1	0	1	A	3
Planned outage (weeks per year)	0	0	0	0	1	0	1	A	3
Technical lifetime (years)	20	20	20	10	20	10	20		
Construction time (years)									
Space requirement (1000m2/MW)									
Ramping configurations									
Ramping (% per minute)	0	0	0	0	0	0	0	A	2
Minimum load (% of full load)	0	0	0	0	0	0	0	A	2
Warm start-up time (hours)	0	0	0	0	0	0	0	A	2
Cold start-up time (hours)	0	0	0	0	0	0	0	A	2
Environment									
PM2.5 (% compared to 100% coal)	0%	0%	0%	0%	0%	0%	0%	A	3
SO2 (% compared to 100% coal)	0%	0%	0%	0%	0%	0%	0%	A	3
NOX (% compared to 100% coal)	0%	0%	0%	0%	0%	0%	0%	A	3
Financial data									
Nominal investment (M$/MWe)	+0.28	+0.28	+0.28	+0.11	+0.32	+0.11	+0.32	AB	1,2,3,4
- of which equipment	-	-	-	-	-	-	-		
- of which installation	-	-	-	-	-	-	-		
Fixed O&M ($/MWe/year)	+3%	+3%	+3%	+1%	+5%	+1%	+5%	A	1,3,4
Variable O&M ($/MWh)	0%	0%	0%	0%	+3%	0%	+3%	A	1,3,4

References:

1 EIA, "Generating unit annual capital and life extension cost analysis," 2019

2 Parsons Brinckerhoff, "Coal and Gas Assumptions," 2014. [Online]. Available: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/315717/coal_and_gas_assumptions.PDF.

3 Danish Energy Agency and Energinet, "Technology Data - Energy Plants for Electricity and District heating generation", 2016 - Updated

4 EPRI, Generic guidelines for the life extension of fossil fuel power plants, 1986

Notes:

A Value depends on the original plant. Value indicates the estimated change from the original value (unit is the same as the parameter).

B Values will depend on those of the plant prior to LTE, however the average fixed O&M cost may increase slightly for the extension period compared with the original lifetime to accommodate the necessary reinvestments during the extended lifetime

C It is assumed that plant emissions prior to the LTE are within the legal limits.

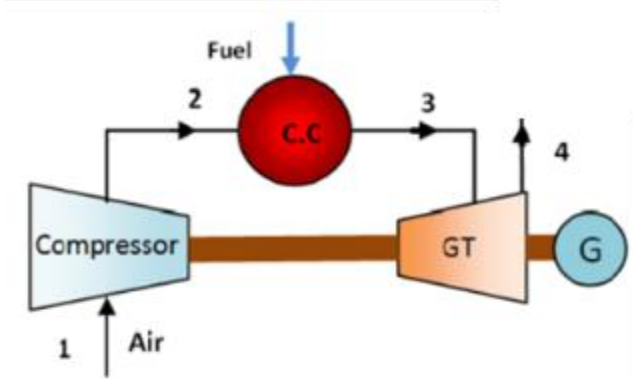
D Investment costs will vary largely, depending on the necessary scope of work. The indicated range represents typical cases where lifetime extended to obtain additional 20 years lifetime.

E Values will depend on those of the plant prior to LTE, however the average fixed O&M cost may increase slightly for the extension period compared with the original lifetime to accommodate the necessary reinvestments during the extended life time.

11. Gas Turbine – Simple Cycle

Brief technology description

The major components of a simple-cycle (or open-cycle) gas turbine power unit are: a gas turbine, a gear (when needed) and a generator.



Process diagram of a SCGT (ref. 1)

Process Diagram of a SCGT (ref. 1)

There are in general two types of gas turbines:

1. Industrial turbines (also called heavy-duty)
2. Aero-derivative turbines

Industrial gas turbines are distinct from aero-derivative turbines in that they have heavier construction in frames, bearings, and blading. Additionally, they typically require longer intervals between services compared to aero-derivatives. Aero-derivative turbines are known for their higher efficiency compared to industrial turbines. The most service-demanding module of an aero-derivative gas turbine can usually be replaced within a couple of days, ensuring high availability.

Gas turbines can be equipped with compressor intercoolers, where the compressed air is cooled to reduce the power needed for compression. The use of integrated recuperators (preheating of the combustion air) to increase efficiency can also be made by using air/air heat exchangers - at the expense of an increased exhaust pressure loss. Gas turbine plants can have direct steam injection in the burner to increase power output through expansion in the turbine section (Cheng Cycle).

Small gas turbines, specifically those below 100 kW known as micro-turbines, often feature combustion air preheating using heat from the gas turbine exhaust (integrated recuperator) to achieve reasonable electrical efficiency, typically between 25-30%.

Input

Typical fuels are natural gas and light oil. Some gas turbines can be fuelled with other fuels, such as LPG, biogas, etc., and some gas turbines are available in dual-fuel versions (gas/oil). Gas-fired gas turbines need an input pressure of the fuel (gas) of 20-60 bar, dependent on the gas turbine compression ratio, i.e., the entry pressure in the combustion chamber. Typically, aero-derivative gas turbines need higher fuel (gas) pressure than industrial types.

Output

Electricity.

Typical Capacities
Simple-cycle gas turbines are available in the 30 kW – 450 MW range.

Ramping Configurations
A simple-cycle gas turbine can start and stop within minutes, making it suitable for supplying power during peak demand. Although less power-efficient than combined cycle plants, they are typically used as peak or reserve power plants, operating from several hours per day to a few dozen hours per year.

Advantages/Disadvantages
Advantages: Simple-cycle gas turbine plants have short start-up/shut-down times, if needed. For normal operation, a hot start will take some 10-15 minutes. Construction times for gas turbine-based simple cycle plants are shorter than steam turbine plants.

Disadvantages: Concerning larger units above 15 MW, the combined cycle technology has so far been more attractive than simple cycle gas turbines, when applied in cogeneration plants for district heating. Steam from other sources (e.g., waste-fired boilers) can be led to the steam turbine part as well. Hence, the lack of a steam turbine can be considered a disadvantage for large-scale simple cycle gas turbines.

Environment
Gas turbines achieve very complete combustion and low emission levels (other than NOx) due to continuous combustion with non-cooled walls. Developments focusing on the combustors have led to low NOx levels. To lower the emission of NOx further, post-treatment of the exhaust gas can be applied, e.g., with SCR catalyst systems.

Employment
The 1605 MW natural gas-fired power plant Muara Karang near Jakarta (1205 MW CCGT + 400 MW steam turbine) is occupying 437 full-time employees.

Research and Development Perspectives
Continuous development is focused on less polluting combustion technologies. Low-NOx combustion technology is being pursued, with trends leaning towards dry low-NOx combustion, which, while increasing the specific cost of the gas turbine, reduces emissions.

Examples of Current Projects
There are currently several gas turbines installed in Indonesia.

References
The description in this chapter is to a great extent from the Danish Technology Catalogue "Technology Data on Energy Plants - Generation of Electricity and District Heating, Energy Storage and Energy Carrier Generation and Conversion". The following sources are used:

1. Nag, "Power plant engineering", 2009.

Data Sheets
The following pages contain the data sheets of the technology. All costs are stated in U.S. dollars (USD), price year 2022. The uncertainty is related to the specific parameters and cannot be read vertically – meaning a product with e.g., lower efficiency does not have a lower price.

Technology

Technology	Simple Cycle Gas Turbine - large system								
	2023	2030	2050	Uncertainty (2023)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	40	40	40	15	150	15	150	I	1,3
Generating capacity for total power plant (MWe)	200	200	200	45	400	45	400	I	1,3
Electricity efficiency, net (%), name plate	34	36	40						1,2
Electricity efficiency, net (%), annual average	33	35	39						1,2
Forced outage (%)	2	2	2						
Planned outage (weeks per year)	3	3	3						
Technical lifetime (years)	25	25	25						
Construction time (years)	1.5	1.5	1.5	1.1	1.9	1.1	1.9	B	3
Space requirement (1000 m^2/MWe)	0.02	0.02	0.02	0.015	0.025	0.015	0.025	B	3
Additional data for non thermal plants									
Capacity factor (%), theoretical	-	-	-	-	-	-	-		
Capacity factor (%), incl. outages	-	-	-	-	-	-	-		
Ramping configurations									
Ramping (% per minute)	20	20	20	10	30	10	30	C	3,6
Minimum load (% of full load)	40	30	15	30	50	10	40	A	4
Warm start-up time (hours)	0.25	0.23	0.2						3
Cold start-up time (hours)	0.5	0.5	0.5						3
Environment									
PM 2.5 (mg per Nm^3)	30	30	30	30	30	30	30		5
SO_2 (degree of desulphuring, %)	-	-	-	-	-	-	-	E	
NO_X (g per GJ fuel)	86	60	20	20	86	20	86	A,D	3,5
CH_4 (g per GJ fuel)	-	-	-	-	-	-	-		
N_2O (g per GJ fuel)	-	-	-	-	-	-	-		
Financial data									
Nominal investment (M$/MWe)	1.12	1.06	0.99	0.85	1.75	0.60	1.25	F,G,H	1
- of which equipment (%)	50	50	50	50	50	50	50		7
- of which installation (%)	50	50	50	50	50	50	50		7
Fixed O&M ($/MWe/year)	26,500	25,700	24,900	19,000	33,000	18,000	31,000	B	1,8
Variable O&M ($/MWh)	3.60	3.50	3.40	2.70	4.50	2.55	4.25	B	1,8
Start-up costs ($/MWe/start-up)	25	25	25	20	35	20	35	B	4

References:

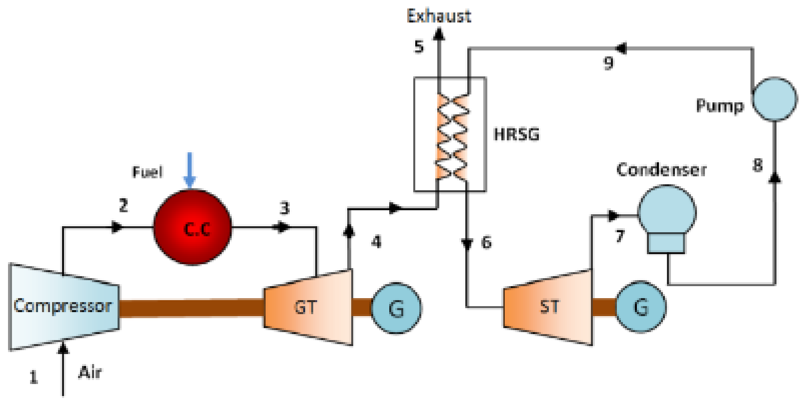
1 MEMR Focus Group Discussions with various stakeholders for the purposes of updating the Technology Catalogue in 2023
2 IEA, World Energy Outlook, 2015.
3 Danish Energy Agency, 2015, "Technology Catalogue on Power and Heat Generation".
4 Deutsches Institut für Wirtschaftsforschung, On Start-up Costs of Thermal Power Plants in Markets with Increasing Shares of Fluctuating Renewables, 2016.
5 Maximum emission from Minister of Environment Regulation 21/2008
6 Vuorinen, A., 2008, "Planning of Optimal Power Systems".
7 Soares, 2008, "Gas Turbines: A Handbook of Air, Land and Sea Applications".
8 Lazard, 2023, "Levelised Cost of Energy +"

Notes:

A Assumed gradidual improvement to international standard in 2050.
B Uncertainty (Upper/Lower) is estimated as +/- 25%.
C Assumed no improvement for regulatory capability.
D Calculated from a max of 400 mg/Nm3 to g/GJ (conversion factor 0.27 from Pollution Prevention and Abatement Handbook, 1998)
E Commercialised natural gas is practically sulphur free and produces virtually no sulphur dioxide
F The investment cost of an aero-derivative gas turbine will be in the higher end than an industrial gas turbine (ref. 5) . Roughly 50% higher.
G Investment cost include the engineering, procurement and construction (EPC) cost. See description under Methodology.
H For 2020, uncertainty ranges are based on cost spans of various sources.
I Based on data collection from Indonesian projects

12. Gas Turbine – Combined Cycle

Brief technology description
Main components of combined-cycle gas turbine (CCGT) plants include: a gas turbine, a steam turbine, a gear (if needed), a generator, and a heat recovery steam generator (HRSG)/flue gas heat exchanger, see the diagram below.



Process diagram of a CCGT (ref. 1)

The gas turbine and the steam turbine are shown driving a shared generator. The gas turbine and the steam turbine might drive separate generators (as shown) or drive a shared generator. Where the single-shaft configuration (shared) contributes with higher reliability, the multi-shaft (separate) has a slightly better overall performance. The condenser is cooled by sea water or a water circulating in a cooling tower.

The electric efficiency depends, besides the technical characteristics and the ambient conditions, on the flue gas temperature and the temperature of the cooling water. The power generated by the gas turbine is typically two to three times the power generated by the steam turbine.

Input
Typical fuels are natural gas and/or light oil. Some gas turbines can be fueled with other fuels, such as LPG, biogas etc., and some gas turbines are available in dual-fuel versions (gas/oil).

Gas fired gas turbines need a fuel gas pressure of 20-60 bar.

Output
Electricity.

Typical capacities
Most CCGT units has an electric power of >40 MW. The enclosed datasheets cover large scale CCGT (100 – 400 MW) and medium scale (10 – 100 MW).

Ramping configurations
CCGT units are to some extent able to operate at part load. This will reduce the electrical efficiency and often increase the NOx emission. If the steam turbine is not running, the gas turbine can still be operated by directing the hot flue gasses through a boiler designed for high temperature or into a bypass stack.
The larger gas turbines for CCGT installations are usually equipped with variable inlet guide vanes, which will improve the part-load efficiencies in the 85-100% load range, thus making the part-load efficiencies comparable with conventional steam power plants in this load range. Another means to improve part-load efficiencies is to

split the total generation capacity into several CCGTs. However, this will generally lead to a lower full load efficiency compared to one larger unit.

Advantages/disadvantages

Large gas turbine based combined-cycle units are world leading with regard to electricity production efficiency among fuel-based power production.

Smaller CCGT units have lower electrical efficiencies compared to larger units. Units below 20 MW are few and will face close competition with single-cycle gas turbines and reciprocating engines.

Gas fired CCGTs are characterized by low capital costs, high electricity efficiencies, short construction times and short start-up times. The economies of scale are however substantial, i.e. the specific cost of plants below 200 MW increases as capacity decreases.

The high air/fuel ratio for gas turbines leads to lower overall efficiency for a given flue gas cooling temperature compared to steam cycles and cogeneration based on internal combustion engines.

Research and development

Gas turbines are a very well-known and mature technology – i.e. category 4.

Continuous research is done concerning higher inlet temperature at first turbine blades to achieve higher electricity efficiency. This research is focused on materials and/or cooling of blades. Continuous development for less polluting combustion is taking place. Increasing the turbine inlet temperature may increase the NOx production. To keep a low NOx emission different options are at hand or are being developed, i.e. dry low-NOx burners, catalytic burners etc. Development to achieve shorter time for service is also being done.

Investment cost estimation

The cost of combined cycles in Indonesia is found to be in line with international standards, although historical costs have significant variation.

Investment costs [$MUSD_{2022}$/MW]	2020	2023	2030	2050
Catalogues:				
New Catalogue (2023)		1.09	1.04	0.96
Existing catalogue (2020)	0.79		0.75	0.69
Indonesian data:				
MEMR FGDs 2023[1]	0.27-2.27			
ESDM[2]		2.19		
International data:				
NREL's ATB		1.16	1.08	1.00
IEA WEO 2023 (average of India and China)	0.68	0.63	0.63	0.63
IEA WEO 2023 (average of Europe and US)		1.00	1.00	1.00
Development curve - cost trend [%]	-	100%	94%	88%

[1]MEMR Focus Group Discussions with various stakeholders for the purposes of updating the Technology Catalogue in 2023

[2]ESDM presentation on "KATADATA Shifting Paradigm: Transition towards sustainable energy". Sampe L. Purba (26 August 2020)

Examples of current projects

Large Scale Combined Cycle Gas Turbine (CCGT): Jawa 2 CCGT Power Plant (Ref. 4)

PLN has operated the Jawa 2 CCGT Power Plant to maintain the reliability of electricity supply in the Java Bali electricity system. This CCGT power plant is located in the area of PT Indonesia Power UPJP Priok, North Jakarta and covering an area of approximately 5.2 hectares. The Jawa 2 CCGT project produces 800 MW of power from 2 x 300 MW Gas Turbine and 1 x 200 MW Steam Turbine. Jawa 2 power plant is a load follower or peaker type. The development of Jawa 2 CCGT plant need an investment cost of 6.3 trillion rupiahs or equivalent to 434.48 million USD and has successfully provide jobs for 2,141 people, including 2,090 local workers. The plant has high efficiency because the Gas Turbine technology used is the 4^{th} generation (M701F4) and Low NOx Type Combustor so it is more environmentally friendly. The gas needs for Jawa-2 CCGT are supplied from PT Nusantara Regas (NR) through Muara Karang Floating Storage Regasification Unit (FSRU) gas facility. For the operation of 1-unit GT (Gas Turbine) at 300 MW, the gas demand would be 72.82 Billion British Thermal Units per Day (BBTUD).

Jawa 2 CCGT Power Plant at North Jakarta (Ref. 5)

Another CCGT power plant project that is being under construction is Jawa 1 CCGT power plant. Different from Jawa 2 which is owned by PLN, Jawa 1 plant is owned by PT Pertamina Power Indonesia, a subsidiary of PT Pertamina, which is an oil company. This is an integrated project of gas infrastructure and power plant. Jawa 1 CCGT has capacity of 1,760 MW, which makes this plant a largest CCGT in South East Asia. This project needs capital cost of 1.8 billion USD. During construction, about 4,600 workers will be recruited and about 200 workers stay when the plant starts to operate commercially. The electricity generated will be sold to PT PLN (Persero) at a price of 5.5038 US cents/kWh or around 797 rupiahs/kWh. The gas infrastructure that will be built includes FSRU. It is scheduled that the construction finishes in September 2021.

References

The description in this chapter is to a great extend from the Danish Technology Catalogue *"Technology Data on Energy Plants - Generation of Electricity and District Heating, Energy Storage and Energy Carrier Generation and Conversion".* The following are sources are used:

1. Ibrahim & Rahman, "Effect of Compression Ratio on Performance of Combined Cycle Gas Turbine", *Int. J. Energy Engineering*, 2012.
2. Nag, "Power plant engineering", 2009.
3. Mott MacDonald, "UK Electricity Generation Costs Update", 2010.
4. https://www.liputan6.com/bisnis/read/3606807/pltgu-jawa-2-beroperasi-pasokan-listrik-jakarta-makin-andal. Accessed in October 2020
5. https://www.dunia-energi.com/pltgu-jawa-2-mulai-pasok-listrik-ke-sistem-jawa-bali/. Accessed in October 2020

Data sheets

The following pages content the data sheets of the technology. All costs are stated in U.S. dollars (USD), price year 2022. The *uncertainty* it related to the specific parameters and cannot be read vertically – meaning a product with lower efficiency do not have the lower price or vice versa.

Technology

Technology	Combined Cycle Gas Turbine								
	2023	2030	2050	Uncertainty (2023)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	100	100	100	40	300	40	300	I	1
Generating capacity for total power plant (MWe)	400	400	400	100	800	100	800	I	1
Electricity efficiency, net (%), name plate	57	60	61	45	62	55	65		1,3,5,10
Electricity efficiency, net (%), annual average	56	59	60	39	61	54	64		
Forced outage (%)	5	5	5	3	10	3	10		1
Planned outage (weeks per year)	5	5	5	3	8	3	8		1
Technical lifetime (years)	25	25	25	20	30	20	30		1
Construction time (years)	2.5	2.5	2.5	2	3	2	3		1
Space requirement (1000 m^2/MWe)	-	-	-	-	-	-	-		
Additional data for non thermal plants									
Capacity factor (%), theoretical	-	-	-	-	-	-	-		
Capacity factor (%), incl. outages	-	-	-	-	-	-	-		
Ramping configurations									
Ramping (% per minute)	20	20	20	10	30	10	30	C	1,2
Minimum load (% of full load)	45	30	15	30	50	10	40	A	5
Warm start-up time (hours)	2	1	1	1	3	0.5	2	A	1,5
Cold start-up time (hours)	4	4	4	2	5	2	5		1,5
Environment									
PM 2.5 (mg per Nm^3)	30	30	30						
SO_2 (degree of desulphuring, %)	-	-	-	-	-	-	-	E	
NO_X (g per GJ fuel)	86	60	20	20	86	20	86	A,D	7,8
CH_4 (g per GJ fuel)	-	-	-	-	-	-	-		
N_2O (g per GJ fuel)	-	-	-	-	-	-	-		
Financial data									
Nominal investment (M$/MWe)	1.08	1.03	0.95	0.74	1.14	0.63	1.03	F,H	1,3,10
- of which equipment (%)	50	50	50	50	50	50	50		9
- of which installation (%)	50	50	50	50	50	50	50		9
Fixed O&M ($/MWe/year)	26,800	26,000	25,200	20,000	33,500	19,000	31,500	B	1,3
Variable O&M ($/MWh)	2.60	2.50	2.40	1.90	3.30	1.80	3.10	B	1
Start-up costs ($/MWe/start-up)	90	90	90	70	115	70	115	B	6

References:

1 MEMR Focus Group Discussions with various stakeholders for the purposes of updating the Technology Catalogue in 2023
2 Vuorinen, A., 2008, "Planning of Optimal Power Systems".
3 IEA, World Energy Outlook, 2015.
4 Learning curve approach for the development of financial parameters.
5 Siemens, 2010, "Flexible future for combined cycle".
6 Deutsches Institut für Wirtschaftsforschung, On Start-up Costs of Thermal Power Plants in Markets with Increasing Shares of Fluctuating Renewables, 2016.
7 Maximum emission from Minister of Environment Regulation 21/2008
8 Danish Energy Agency, 2015, "Technology Catalogue on Power and Heat Generation".
9 Soares, 2008, "Gas Turbines: A Handbook of Air, Land and Sea Applications".
10 IEA, Projected Costs of Generating Electricity, 2015.

Notes:

A Assumed gradidual improvement to international standard in 2050.
B Uncertainty (Upper/Lower) is estimated as +/- 25%.
C Assumed no improvement for regulatory capability.
D Calculated from a max of 400 mg/Nm3 to g/GJ (conversion factor 0.27 from Pollution Prevention and Abatement Handbook, 1998)
E Commercialised natural gas is practically sulphur free and produces virtually no sulphur dioxide
F Investment cost include the engineering, procurement and construction (EPC) cost. See description under Methodology.
H For 2020, uncertainty ranges are based on cost spans of various sources. For 2050, we combine the base uncertainity in 2020 with an additional uncertainty span based on learning rates variying between 10-15% and capacity deployment from Stated Policies and Sustainable Development scenarios separately.
I Based on data collection from Indonesian projects

13. Retrofit of Gas Plants - Hydrogen Co-Firing in Gas Turbines

Brief technology description

Hydrogen can be used as a fuel to partially replace (co-firing) or totally replace natural gas in gas turbines. Fundamentally, the challenges of using hydrogen-containing fuels for power generation with standard turbine technologies result from the differences in combustion characteristics of H_2 compared to CH_4. For example, the flame temperature (or reaction temperature) of H_2 is about 5-10% higher, potentially leading to higher thermal NO_x production and creating challenges related to degradation of materials and coatings. Due to the lower volumetric energy density (i.e. lower heating value) of hydrogen compared to methane, fuel supply lines and other system components may need to be resized to account for the increased volume of fuel needed to maintain the same power output.

Another difference, and one of the most technically challenging, is the faster flame speed of hydrogen. For example, in a dry low NO_x combustion system (DLN)(today's state-of-the-art, high efficiency gas turbines use DLN combustors designed for burning NG with extremely low NO_x and CO emissions), flow velocity would need to be higher to prevent the flame from flashing back, the unintentional propagation of the flame upstream into the premixing combustion hardware. At about 95% H_2, the upper (flashback-driven) limit of a turbine's operating range experiences a relatively large decrease. This narrows the stable operating range, presenting one of the biggest challenges to design high hydrogen capable pre-mixed DLN systems.

On the other hand, hydrogen co-firing implies some advantages such as the lower limit of a turbine's operating range gradually decreases with increasing H_2 content, and CO production is not a concern. These properties potentially improve turndown capabilities (the ability to run at lower-than-rated power output) relative to current Natural Gas Gas Turbines (NG GT). This potentially improved turndown capability is a flexibility advantage that can support a more integrated energy network (ref. 4).

The main impacts affecting the operation of gas turbine when co-firing with hydrogen, are listed in the following table, including the related potential solutions.

Potential impacts and potential technical solutions of hydrogen co-firing in gas turbines.

Property	Properties of H_2 (relative to NG)	Potential impact	Potential technical solutions
Carbon monoxide production	100% reduction	• CO production removed as a limitation to operating parameters	N/A
Energy density	Vol: <1/3 Mass: ~2.5x higher [7,8]	• More fuel by volume for same heat released	• Increased flow velocity
Flame speed	9x higher[7]	• Increased flashback risk	• Increased flow velocity • New fuel injection designs (e.g., fuel staging/ micromixers)
Flame temperature	~5-10% increase[7]	• Increased thermal NOx production; • Increased materials/coating degradation	• Larger selective catalytic reduction bed to compensate; fuel staging/new combustion designs • New materials/coatings
Lean blowout (LBO) limits	~50% increase in LBO margin[7]	• Increased turndown capability	N/A
Lower flammability limit	20% lower[9]	• Safety – more flammable in event of leak • More challenges to detection	• New leak detection methods/ gas sensors
Molecular size	8x lighter	• Increased tendency to leak	• More welded connections, new seals/tighter connections

Combustion systems with diffusion flames and nitrogen or steam dilution can handle up to 100% vol. hydrogen. Nevertheless, these systems have several disadvantages, including reduced efficiency compared to systems without dilution, higher NO_x level compared to lean-premixed technology, higher plant complexity and thereby higher capital and operational costs.

Fuel transportation
When using hydrogen as fuel, it is of utmost importance to take into consideration the delivery pressure and temperature to avoid embrittlement in the pipelines and other auxiliaries. Existing piping and gas turbine valves shall be subject to retrofit when a gas turbine manifold running with natural gas is forecasted to run with H_2. Changes may include new valves design with a different sealing arrangement, and potentially new piping material.

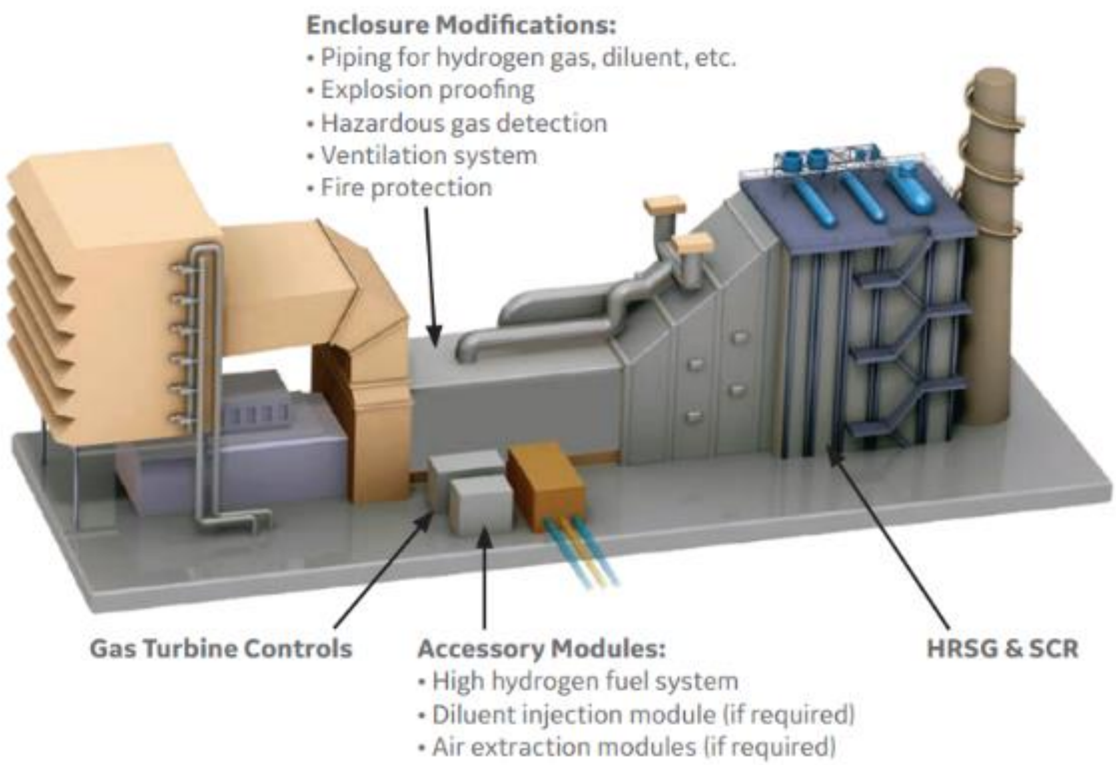
Another point to consider is the incorrect purge of H_2 within the system. Indeed, the more components involved, the higher the likelihood for some H_2 to remain trapped within them, leading to explosion risks when doing maintenance or repair. On that basis, proper measurement apparatus for H_2 traces should be considered as part of any H_2 use with GTs. In addition, purge systems using CO_2 or nitrogen must be taken into consideration.

While hydrogen embrittlement does not occur in stainless steel equipment at 50 bar and 100°C, increasing the temperature to around 200°C may cause H_2 migration through the material. Indeed, H_2 embrittlement is a concern at temperatures above 200°C, although 316L grade stainless steel is considered quite suitable in reducing this effect. It is worth noting that hydrogen embrittlement is not only related to temperature, but also to the stress endured by the material which affects the permeation of H_2.

Hydrogen is flammable and explosive over a wider range of concentrations in air at standard atmospheric temperature compared to natural gas (Hydrogen: 4-75% vol. and natural gas: 15-59% vol.). Therefore, handling becomes a major safety concern in comparison to methane or gasoline for instance. Gas dispersion is a key point to reduce the risk. Knowing this gas is lighter than methane, it may create accumulation at height which is not expected when running natural gas. Refineries use dedicated gas detection devices for H_2.

Every gas turbine must be evaluated on a case-by-case basis for hydrogen consumption, considering fuel skid, controls, and combustion system. As a general guideline, there are constraints to consider, namely (ref. 1):

- Low levels of hydrogen mixed with natural gas, to a level that does not require any changes to materials, designs and control and protection. These levels may be in the range of 0-10% vol, depending on the system.
- Medium levels of hydrogen mixed with natural gas, to a level that does not require significant changes to materials, designs, control, and protection. These levels may be in the range of 10-30% vol.
- Higher levels of hydrogen, which require a wider retrofit scope, and which suggest that hydrogen fuel capability should be maximized given the assumption of fuel delivery, combustion module, control and protection retrofit 30-100% vol. A retrofit package is likely to include:
    - Core gas turbine combustion module replacement
    - Instrumentation and fuel control system modification
    - Plant fuel delivery system modification, including modified purge, metering, gas composition monitoring, safety systems (including package sensing and ventilation upgrades) and the provision of a start-up fuel supply.
    - It is likely that the economics of such a retrofit assume re-use of existing hot gas path designs of components.



Example of a hydrogen gas turbine and its components

The corresponding volume and energy share for the different mixing ratios of hydrogen and natural gas is shown in the following table. In this report, the share of H_2 when co-firing in gas turbine plant is defined in terms of energy share. 20% share of energy of H_2 with natural gas is corresponding to approximate 45% share of volume of H_2.

Corresponding volume and energy share for the different mixing ratios of hydrogen and natural gas (ref. 2)

Volume share H_2 (%)	Energy share H_2 (%)
30	11
50	23
77	50
100	100

Impact on plant performance and flexibility

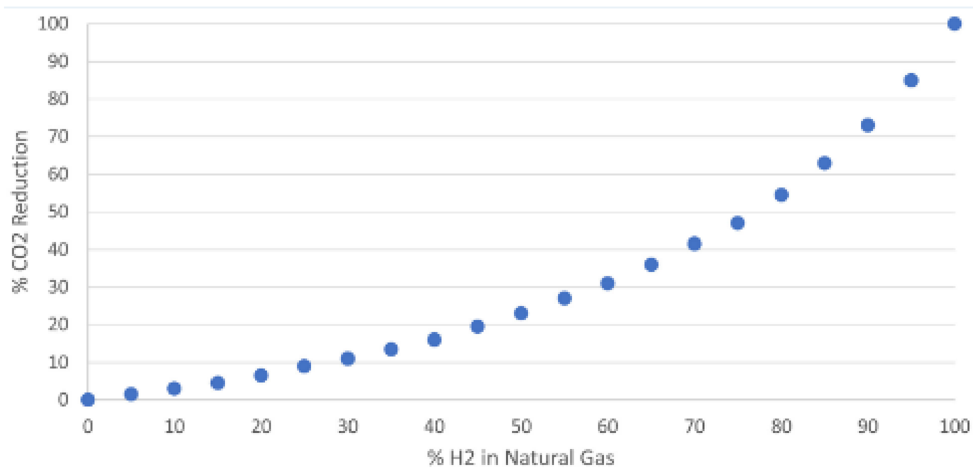
The research conducted so far suggests that gas turbine power output and performance should stay similar for natural gas-fired units subjected to a combustion system replacement and high hydrogen firing rates (ref. 1,7).

The increased reactivity and higher flame speeds of hydrogen force new combustion and fuel injection designs to be adopted for high-rate hydrogen fueling. A likely problem will be the degree to which a plant capable of high hydrogen combustion rates will then be able to operate at high natural gas firing rates. It is probable that at some point during the natural-gas-to-hydrogen transition, compromises will have to be made on emissions, power output, or power output ramp rates. Due to the higher reactivity of hydrogen, the turndown is likely to be improved when operating at higher hydrogen concentrations as CO emissions will be reduced.

Ramping configurations
For grid support services that rely on high ramp rates (e.g. frequency response), it is likely that some short-term adaptation of the fueling mix and a more complex fuel delivery control system may be required. These solutions may differ between plant types, so applicable regulations may need to reflect a range of engineering solutions.

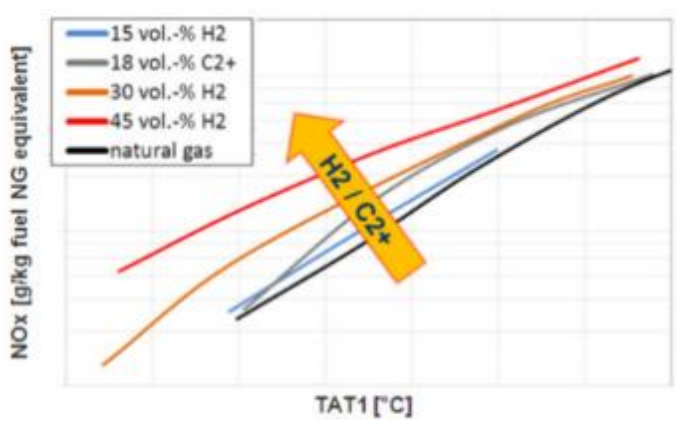
Environment
Effect on emissions
Reduction in CO_2 emissions is the main advantage of hydrogen co-firing in a gas turbine power plant. The hydrogen should then be produced by renewable energy (such as using wind/solar energy to electrolyze water), called green hydrogen.

Fuel blends with higher H_2 content—typically expressed on a volumetric basis—result in lower CO_2 emissions per MWh, but the relationship is nonlinear as shown in the figure below.



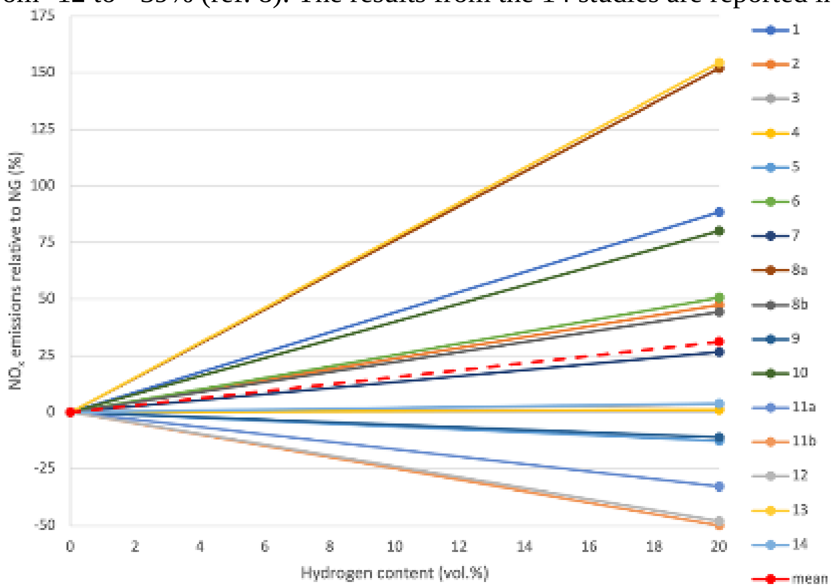
CO_2 Reduction for H2-NG blends by volume (ref. 4)

Since the flame temperature of H_2 is 5-10% higher than natural gas, co-firing H_2 in gas turbines will tend to release more NO_x emission as shown in the figure below.



Comparison of levels of H2 co-firing ratio in term of NO_x emission in GT Alstom GT26 (ref. 7)

During the study reported in (ref. 8), an evaluation of NO_x emission in gas turbine plants at a level of co-firing H2 in 0-20% of volume was carried out. The results showed that on average, co-firing hydrogen at the ratio of 20% volume will cause NO_x emission to increase by 30%. However, In the same article it was reported a literature review including 14 studies that evaluated the NOx emission from hydrogen/natural gas blends with mixtures between 5% and 20% v/v. The results have shown high variability: the mean change across the 14 studies is 8%. At 20% hydrogen blend, the effects on emissions ranged from -50 to +154%, while at 5% hydrogen blends, the emissions changed from -12 to +39% (ref. 8). The results from the 14 studies are reported in the figure below.



NOx emissions for hydrogen/natural gas blends in the range 5-20% v/v as reported from 14 different studies (represented by the 14 colored lines) (ref. 8)

Investment cost estimation

In the study (ref. 2), it was proposed a capital cost increase as percentages of the costs for conventional gas turbines for different levels of hydrogen mixing capabilities. The cost was given both for upgrading existing gas turbines and investing in new gas turbines based on discussions with industrial partners.

Details of CAPEX increase compared to *existing gas turbine (ref. 2)*

Hydrogen mix [vol-%]	Hydrogen mix [energy-%]	Hydrogen upgrade of existing gas turbines [% of base CAPEX]	New hydrogen gas turbines [% of base CAPEX]	Description of cost increase
30%	~11%	1	101	Fuel system
50%	~20%	7	103	Fuel system and burner tip
77%	~50%	10	105	Fuel system and burner
100%	100%	25	115	Combustion chamber

At the level of co-firing 20% hydrogen in term of energy (50% in term of volume), the investment cost will increase about 7%, including retrofit of fuel system and burner.

O&M cost: Since there are modifications of fuel delivery system, metering, gas composition monitoring, safety system and burner when co-firing hydrogen, the O&M cost will tend to slightly increase, from 3 to 5%, depending on the co-firing rate of hydrogen.

Examples of current projects

Most major turbine engine manufacturers have made substantial progress in implementing hydrogen into their accepted fuel profiles. A summary of several commercial technologies produced by the original equipment manufacturers (OEMs) that have achieved commercially viable hydrogen combustion in gas turbines is shown in the following table. EU Turbines, an association of European turbine manufacturers that includes the four OEMs listed in the table as well as other major vendors, is committed to producing gas turbines capable of operating with 100% H_2 commercially available by 2030.

Hydrogen combustion technologies from the largest OEMs (ref. 4)

OEM	Type	Class	H_2 (%vol)
MHI	Diffusion	1200~1400	Up to 100%
	Pre-Mixed	1600	Up to 30%
	Multi-cluster	1650	Up to 100%
GE	DLE		Up to 5%
	SAC		30-85%
	SN	B, E class	90-100%
	MNQC	E, F class	90-100%
	DLN 1	B, E class	Up to 33%
	DLN 2.6+	F, H class	Up to 15%
	DLN2.6e	9HA class	Up to 50%
Siemens	DLE		2-15%
	WLE		15-100%
	DLE	E, F, H class	30%
	Diffusion	E, F, H class	Up to 100%
	DLE	E, F, H class	Up to 30%

In 2022, several new construction projects for gas turbine plants applying natural gas-hydrogen co-firing have been reported, such as: the plant in Hunter valley, Australia (capacity 2x330 MW, with mixed ratio of 15% hydrogen, expected to operate in 2023), Intermountain project, USA (replacing the 1800 MW coal-fired power plant with an 840 MW gas turbine plant, mixing 30% hydrogen by 2025 and aiming at 100% hydrogen by 2045). In addition, a 172 MW gas turbine renovation project with a 40% hydrogen mixing ratio at the Linden cogeneration power plant, USA is being implemented and is expected to come into operation in 2022 (ref. 5).

HDF Sumba Pilot Project (ref 9)

HDF Energy is a new type of private power producer (IPP) focused on generating clean and powerful utility-scale power. The Multi-MW Renewstable® power plant was created by HDF Energy. This long-term infrastructure (20+ years) combines solar or wind electricity with long-term hydrogen storage.

References:

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8. L. Wright, C. Lewis, “Emission of Nox from blending of hydrogen and natural gas in space heating boilers”, 2022
9. https://www.hdf-energy.com/id/

Data sheets

The following pages contain the data sheets of the technologies. All costs are stated in U.S. dollars (USD), price year 2022. The uncertainty is related to the specific parameters and cannot be read vertically – meaning a product with e.g., lower efficiency does not have a lower price.

Technology

Technology	CCGT - co-firing 20% hydrogen (in term of energy)								
	2023	2030	2050	Uncertainty (2030)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	100	100	100	40	300	40	300	C	6
Generating capacity for total power plant (MWe)	400	400	400	100	800	100	800	C	6
Electricity efficiency, net (%), name plate	0	0	0	0	-2	0	-2	A	1,4
Electricity efficiency, net (%), annual average	0	0	0	0	-2	0	-2	A	1,4
Forced outage (%)	0	0	0	0	1	0	1	A	
Planned outage (weeks per year)	0	0	0	0	0	0	0	A	
Technical lifetime (years)									
Construction time (years)									
Space requirement (1000m2/MW)									
Ramping configurations									
Ramping (% per minute)	0	0	0	0	0	0	0	A	1,4
Minimum load (% of full load)	-3	-3	-3	-1	-5	-1	-5	A	1,4
Warm start-up time (hours)	0	0	0	0	0	0	0	A	1,4
Cold start-up time (hours)	0	0	0	0	0	0	0	A	1,4
Environment									
PM2.5 (% compared to 100% natural gas)	-20%	-20%	-20%	-10%	-20%	-10%	-20%	A	4
SO2 (% compared to 100% natural gas)	-20%	-20%	-20%	-10%	-20%	-10%	-20%	A	4
NO_x (% compared to 100% natural gas)	40%	40%	40%	10%	60%	10%	60%	A	4,5
Financial data									
Nominal investment (M$/MWe)	+0.09	+0.09	+0.08					A,B,D	2
- of which equipment	-	-	-	-	-	-	-		
- of which installation	-	-	-	-	-	-	-		
Fixed O&M (% compared to 100% natural gas)	3%	3%	3%	1%	5%	1%	5%	A	2
Variable O&M (% compared to 100% natural gas)	3%	3%	3%	1%	5%	1%	5%	A	2

Technology	CCGT - co-firing 100% hydrogen (in term of energy)							
	2030	2050	Uncertainty (2030)		Uncertainty (2050)		Note	Ref
Energy/technical data			Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	100	100	40	300	40	300	C	6
Generating capacity for total power plant (MWe)	400	400	100	800	100	800	C	6
Electricity efficiency, net (%), name plate	0	0	0	-3	0	-3	A	1,4
Electricity efficiency, net (%), annual average	0	0	0	-3	0	-3	A	1,4
Forced outage (%)	0	0	0	1	0	1	A	
Planned outage (weeks per year)	0	0	0	0	0	0	A	
Technical lifetime (years)								
Construction time (years)								
Space requirement (1000m2/MW)								
Ramping configurations								
Ramping (% per minute)	0	0	0	0	0	0	A	1,4
Minimum load (% of full load)	-5	-5	-3	-10	-3	-10	A	1,4
Warm start-up time (hours)	0	0	0	0	0	0	A	1,4
Cold start-up time (hours)	0	0	0	0	0	0	A	1,4
Environment								
PM2.5 (% compared to 100% natural gas)	-100%	-100%	-100%	-100%	-100%	-100%	A	4
SO2 (% compared to 100% natural gas)	-100%	-100%	-100%	-100%	-100%	-100%	A	4
NO_x (% compared to 100% natural gas)	-100%	-100%	-100%	-100%	-100%	-100%	A	4,5
Financial data								
Nominal investment (M$/MWe)	+0.31	+0.29					A,B	2
- of which equipment	-	-	-	-	-	-		
- of which installation	-	-	-	-	-	-		
Fixed O&M (% compared to 100% natural gas)	5%	5%	3%	10%	3%	10%	A	2
Variable O&M (% compared to 100% natural gas)	5%	5%	3%	10%	3%	10%	A	2

References:

1 "Hydrogen gas turbines," ETN Global, 2020. https://etn.global/wp-content/uploads/2020/01/ETN-Hydrogen-Gas-Turbines-report.pdf.

2 S. Öberg, M. Odenberger, and F. Johnsson, "Exploring the competitiveness of hydrogen-fueled gas turbines in future energy systems," Int. J. Hydrogen Energy, vol. 47, no. 1, pp. 624–644, 2022, doi: https://doi.org/10.1016/j.ijhydene.2021.10.035.

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6 PLN, 2023, data provided the System Planning Division at PLN

Notes:

A Value depends on the original plant. Value indicates the estimated change from the original value (unit is the same as the paramter).

B The nominal investment assumes that exclude investment for a general lifetime extension campaign

C Based on data collection from Indonesian projects

D All costs for extra component needed for running the turbine with H2 and for resizing equipment in order to maintain the same power output capacity of the plant is included in the investment cost. The cost of improving pipelines outside the plant-land plot is not included.

14. CO_2 Capture and Storage (CCS)

This chapter describes the essential features and main uses of the most prominent carbon capture and storage (CCS) technologies. However, the data presented at the end of this chapter focuses only on the performance and costs of carbon capture (and not the storage and eventual utilization), as the focus of this analysis is power generation technologies (and the downstream processes largely vary by application/geography). The focus is on post-combustion, pre-combustion and oxy-fuel combustion.

Technology description

The last few decades increase in atmospheric CO_2 concentration tis largely attributable to the combustion of fossil fuels, waste, and biomass. CCS can allow the presence of fossil fuels waste, and biomass in a CO_2-constrained future. CCS can generate negative emissions if used on biomass, which could be necessary to limit temperature increase over time according to scenarios from IEA and IPCC. The CCS process consists of several steps divided into Capture, Compression, Transport, and Storage, which are described in the following sections.

CO_2 Capture

The CO_2 volume from fossil fuel or biomass-fired power plants ranges from 3-15% of the total flue gas volume. For all the power plants – coal, natural gas and biomass, the carbon capture process can take place prior to combustion, after combustion or via oxy-fuel combustion (ref. 1).

1. **Post-Combustion Capture**

In post-combustion capture, the CO_2 is separated from the flue gas. The dominant post-combustion technology is absorption or scrubbing of CO_2 in chemical solvents like amine solutions, which are commercially available and have been widely used across sectors (as for power generation, essentially in the Americas). The CO_2 is stripped from the solvent by raising the temperature (ref. 2).

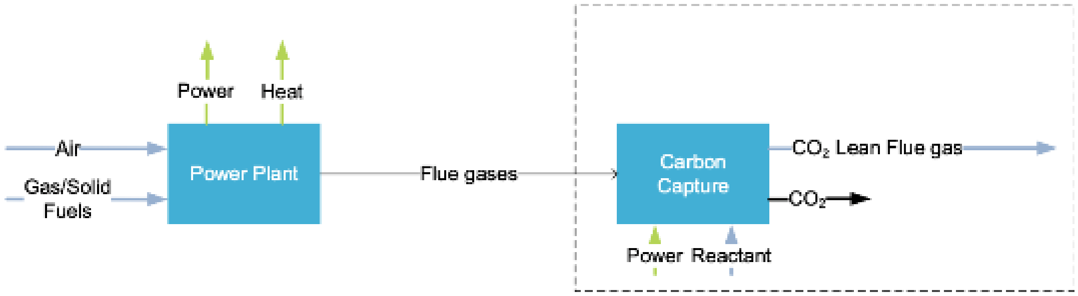


Figure 4: Post-combustion capture. Source: Danish Energy Agency.

2. **Pre-Combustion Capture**

In pre-combustion capture, the CO_2 is captured prior to combustion as in coal gasification or natural gas decarbonization, where hydrogen and carbon dioxide are produced. The hydrogen is used as a fuel and the CO_2 is removed (ref. 1). The most common separation technology are solvents, which scrub the CO_2 out of the syngas and then release it at high temperature or low pressure. This requires additional thermal power that can add up to 15% of the net power output for both pre- and post-combustion. Amine-based solvents are the most widespread (ref. 3).

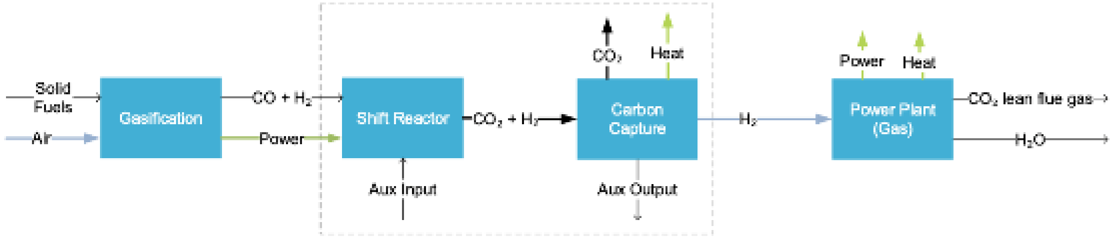


Figure 5: Pre-combustion capture. Source: Danish Energy Agency.

3. **Oxy-Fuel Combustion Capture**

   In oxy-fuel combustion the nitrogen in the air is removed by an Air Separation Unit (ASU), so the fuel is combusted in an atmosphere of oxygen and recycled CO_2. As an alternative to the ASU, surplus oxygen from electrolysis plants can be used to feed the combustion. This results in a flue gas that only contains water vapor and CO_2, where the water vapor can be condensed easily, giving a highly concentrated CO_2 steam (ref. 4).

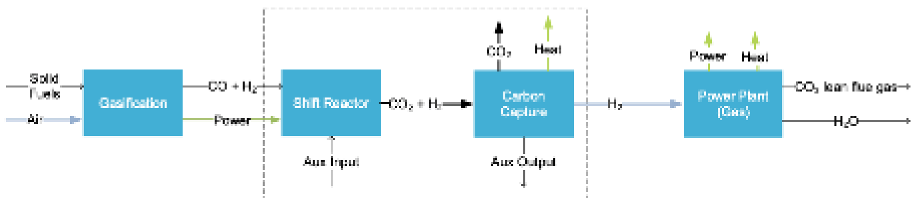


Figure 6: Oxy-Fuel combustion process. Source: Danish Energy Agency.

In all three methods, once the CO_2 is captured, it later needs to be compressed and transported to storage.

CO_2 compression and liquefaction

A major barrier for extensive use of CO_2 removal technology is the high cost of separating and compressing the CO_2. The additional energy required for this process typically reduces efficiency by 10%. To transport the CO_2 by pipeline, a suitable pressure for transport is 10 to 20 MPa, whereas to be transported by ship, it needs to be liquified.

CO_2 transportation

It is necessary to transport the captured CO_2 from the power plant to a suitable reservoir, where it can be injected and permanently stored. This can be done via specifically designed pipelines, via ship or road transportation. In the US a network of over 8000 km carries sequestered CO_2 to depleted oil fields in order to increase the well's yield. The pipeline costs are proportional to distance, but they may increase in congested and heavily populated areas by 50 to 100% respect to pipelines in remote areas like crossing mountains, natural reserves or roads. Offshore pipelines are 40-70% more expensive to similar pipelines on land. Alternatively, ships like LPG tankers can be used, where the cost is less dependent on distance. However, there are step-in costs which include a stand-alone liquefaction unit potentially remote from the power plant. Therefore, for short to medium distances and large volumes, pipelines are the most cost-effective solution.

CO_2 storage
Captured CO2 can be injected for storage in deep geological formations e.g. in oil and gas fields both onshore and offshore and in saline formations as illustrated in the figure below. Storage in saline formations is currently the most widespread method for long term CO_2 storage globally, because saline aquifers have a large potential volume and are common (ref. 4).

The first method involves injecting CO2 as a dense phase supercritical fluid into declining oil and gas reserves so that pressure favors oil displacement and extra oil is extracted (Enhanced Oil Recovery – EOR) (ref. 5). Oil and gas fields are the leading storage options because of their ability to help offset storage costs with increased production of oil and gas. But to achieve long-term sustainability and decarbonization, the method, technology and economy should be assessed avoiding the combination with extra oil and gas extractions.

In addition, unlike saline aquifers and coal seams, oil and gas have existing infrastructure that can be used for CO_2 transportation. Additionally, the typical permeability of the coal seams storage option might lead to risks of leakage, which must be avoided.

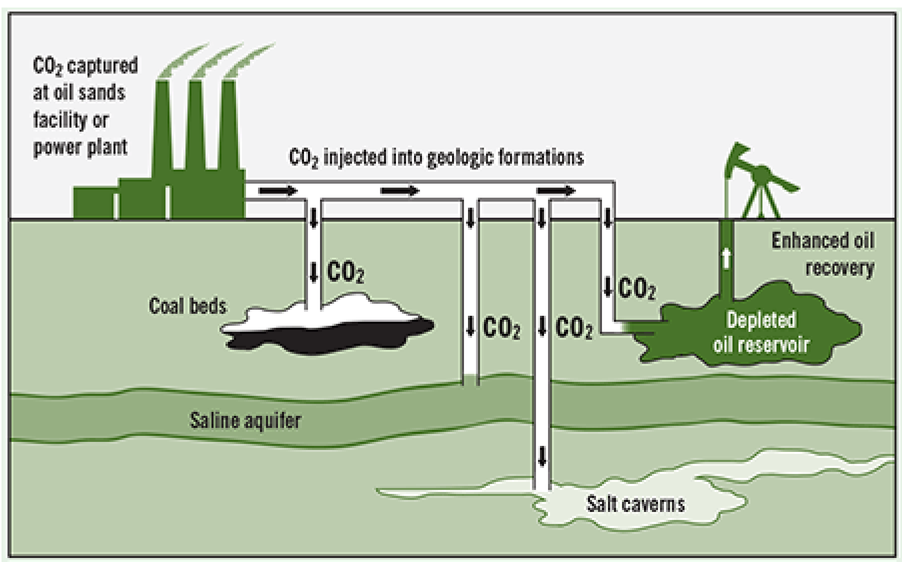


Figure 7: Post-capture treatment of CO2. Source: Energywatch.

Measurement, monitoring, and verification
Measurement, Monitoring, and Verification (MMV) is a process to accurately measure and track the injection and storage of CO_2 in a storage site. It involves continuous monitoring of the CO_2 plume at different depths in the geologic column: at the surface, the biosphere beneath the surface, the geosphere beneath the biosphere, and in the storage reservoir. The monitoring techniques at each of these depths are selected based on the parameters being monitored and the required frequency and timing of the monitoring measurements.

MMV is crucial in ensuring the secure storage of CO_2, providing confidence to the public and regulators, as well as earning CO_2 credits. It helps to identify and quantify the position of the CO_2 plume and detect any potential leakage, assess the movement of CO_2 over time, and evaluate short- and long-term risks associated with the storage.

In addition, a robust data management system is necessary to store, analyze, and ensure the long-term availability of the MMV data. This enables continuous evaluation of the performance of the storage site and identification of any issues that may arise.

CO_2 utilization

This catalogue for power generation technologies focuses on the sequestration process and does not look at the possible benefits accruing from CCS storage and utilization. These are very dependent on application, infrastructure needs and market appeal. Historically and in perspective, CO_2 captured from point sources, such as thermal power plants, can be utilized for the production of synthetic fuels such as methanol and methane. The former consists in injecting CO_2 in declining oil reserves so that pressure favors oil displacement and extra oil is extracted (ref. 5), the second makes use of CO_2 in particular reactors where a hydrogen-based reactant combines with carbon dioxide to yield different hydrocarbons.

Input

- In pre-combustion capture, syngas (predominantly H_2, CO and CO_2).
- In post-combustion capture, CO_2 in flue gas from power plant combustion.
- In the oxy-fuel combustion, a stream of CO_2 and H_2O where CO_2 is found at relatively high concentrations.

Output

The main outputs are stored CO_2 and CO_2-lean flue gas, but if it is not stored, CO_2 can be converted into value-added products, for instance for the food and beverage industry or for manufacturing chemical products (ref. 4).

Ramping

A power plant's regulation ability is roughly uninfluenced by adding post-combustion capture. However, the CO_2 content of the flue gas decreases at part load, consequently, the capture costs per ton increase. For this reason, it may be preferred to operate CCS plants at base load.

Advantages and disadvantages

Advantages

- **Post-combustion capture**. It is the most mature CCS technology and can be applied to most of the existing coal-fired or thermal power plants including the biomass plants
- **Pre-combustion capture**. It is mostly applied to power plants that use coal and gas as fuel. It involves capturing CO_2 from syngas. Syngas is concentrated in CO_2 and at high partial pressure, which extends the range of technologies available for separation and allows reducing compression costs. This allows a lower operational cost than post combustion capture. Pre-combustion is applicable to powerplants that use gas or coal as a fuel.
- **Oxy-fuel combustion**. Very high CO_2 concentrations in the flue gas, so complex post-combustion separation can be avoided; CO_2 is obtained by getting rid of the water through simple condensation. Power plants can also be retrofitted to include oxy-fuel combustion (ref. 6). It is mostly applied to power plants that utilize coal as a fuel.

Disadvantages

- **Post-combustion capture**. The CO_2 is diluted in the flue gas and at ambient pressure, which makes it harder to capture the CO_2. The technology needs large amounts of thermal power for the regeneration of the carbon capturing substance.

- **Pre-combustion capture**. The cost of equipment is high, and it requires supporting systems such as an air separation unit and shift converter. Suitable for IGCC plants; natural gas plants need an *auto-thermal reforming* process before fuel utilization.
- **Oxy-fuel combustion**. Cryogenic O_2 production is expensive. Recycling the cooled CO_2 is necessary to maintain temperature within combustor materials, which decreases efficiency and adds auxiliary load (ref. 6).

More generally, leakage during transportation or storage can lead to environmental issues like ocean and soil acidification. It can occur due to fractures and faults in the earth crust (ref. 7), or to pipeline leakage. Cost of CCS and lack of a CO_2 economy have been identified as the major challenges preventing the widespread adoption of this technology (ref. 8).

Environment

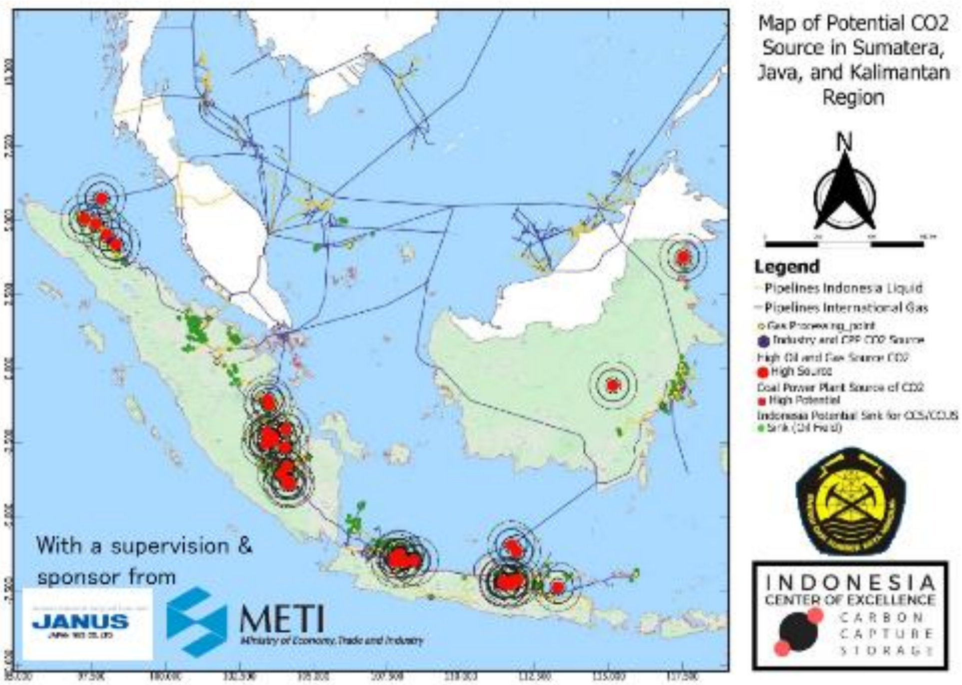
CCS has an overall positive effect on air pollution, however, it consumes 15-25 % of the energy produced by a power plant, depending on the technology that is being used. This means that the emissions of some pollutants will increase not only in the facilities, but also in the emissions caused by extraction and transport of the additional fuel.

- **Sulphur dioxide** (SO_2). SO_2 emissions in coal fired plants fall when CO_2 is captured. Plants with CCS are normally equipped with improved Flue Gas Desulfurization (FGD). IGCC plants already have low SO_2 emissions regardless of CCS due to the Acid Gas Removal section.
- **Particulate matter (PM) & nitrogen oxide** (NO_x). They are expected to rise proportionally with the increase in primary energy use due to the reduction in efficiency caused by CCS. NO_x and PM are not caught by the amine system, and therefore emissions per output grow when fuel consumption pr. output increases. However, the emission level per GJ fuel is the same (ref. 9).
- **Ammonia** (NH_3). It is the only pollutant where a significant increase in emissions is expected, due to the degradation of amine-based solvents (ref. 7).

Research and Development

Extensive research and development work is required in order to develop and optimize techniques that reduce barriers for a wider use, i.e. achieve greater efficiency, confidence and monitoring of storage, mitigation strategies (should there be a leak) and integration of technologies that require scale and lower cost.

The Research and Development organizations in Indonesia such as LEMIGAS, The Agency of R&D for Energy and Mineral Resources and the Ministry of Energy and Mineral Resources Republic of Indonesia support CO_2 capture and storage. Some pilot cases have been installed and several storage sites have been identified. A roadmap has been set to have a demonstration stage in the next 10 years (2020-2030), before starting a commercial phase (ref. 10). The figure below shows a map with CO_2 sources and sinks in Indonesia, where the power sector point sources are shown in red dots.



CO_2 point sources in Indonesia (ref. 18).

Examples of current projects

- *Sukowati pilot project* is an oilfield located in East Java, Indonesia. It has 5 existing wells, one of which is not in production and will be used as a CO_2 injection well with the objective of EOR. If the pilot proves to be successful, a commercial-scale project could be deployed, involving 35 existing production wells, and drilling new CO_2 and water injection wells (ref. 11).

Other examples of Large-Scale Commercial Carbon Dioxide Capture projects:

- **Petra Nova Carbon Capture**:
  This power plant located in Texas has the world's largest post-combustion CO_2 capture system. It has been operating since 2017, when it was retrofitted with a 1.4 Mtpa (Mega-ton-per-annum) CO_2 capture facility (ref. 12). CO_2 is sent to an off-site oil field. In Summer 2020, the Petra Nova carbon capture power project went offline due to low oil prices following the Covid-19 pandemic.
- **Tuticorin CCU Project**:
  This project is a carbon capture and utilization system in Chennai, India, started operating in 2016 for a power plant with 5 coal-fired units of 210 MW each (ref. 13). It can capture 60.000 CO_2 tonnes/year from the flue gas, which is utilized for baking soda and ash. The technology is running without subsidy due to a new CO_2 stripping chemical, which is slightly more efficient than amine (ref. 14).
- **Shanghai Shidongkou 2nd Power Plant Carbon Capture Demonstration Project**:
  It is a coal-fired 600 MW demonstration plant for post-combustion carbon capture in China. The project started in 2009 and started operation in 2011, with a cost of \$24 million. The Carbon Capture technology used is post-combustion capture using an amine mix. After capture, the CO_2 is sold for commercial use (ref. 16).

- **Boundary Dam Unit#3:**
  The coal-fired station is located in Canada. It produces 115 MW of power and post-combustion CCS was installed in 2014. The capture rate is up to 90% and the plant sequesters around 1 million tonnes a year with amine technology. The project had a cost of $1.24 billion, of which half went for CCS installation and the other half for plant modernization. CO_2 is sold for EOR purposes (ref. 17).

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1. Energinet & DEA, 2020, "*Technology Data: Generation of Electricity and District Heating*"
2. National Energy Technology Laboratory, "*Post-combustion CO_2 Capture*", Link, Accessed: 24th September 2020
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4. M.N. Anwar, 2018, "*CO2 capture and storage: A way forward for sustainable environment*"
5. British Geological Survey, "How can CO_2 be stored", Link, Accessed: 24th September 2020
6. José D. Figueroa, 2008, "*Advances in CO_2 capture technology—The U.S. Department of Energy's Carbon Sequestration Program*"
7. European Environment Agency, "*Carbon Capture and Storage could also impact air pollution*", Link, Accessed: 24th September 2020
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16. Cornot-Gandolphe S., "Carbon capture, storage and utilization to the rescue of coal", 2019.
17. Preston C. et al., "An update on the integrated CCS project at SaskPower's Boundary Dam Power Station", 2018.
18. Sule, M.R., *State of Development in Carbon Capture Utilization and Storage in Indonesia and future perspectives*, 2020.

Data sheets

The following pages contain the data sheets of the technologies. All costs are stated in U.S. dollars (USD), price year 2022. The uncertainty is related to the specific parameters and cannot be read vertically – meaning a product with e.g, lower efficiency does not have a lower price.

Technology

Technology	Supercritical coal power plant with CCS, new plant								
	2023	2030	2050	Uncertainty (2023)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	540	540	540					A	1
Generating capacity for total power plant (MWe)	540	540	540					A	1
Electricity efficiency, net (%), name plate	29	30	31					A	1,9
Electricity efficiency, net (%), annual average	28	29	30					A	1,9
Forced outage (%)	7	7	7						
Planned outage (weeks per year)									
Technical lifetime (years)									
Construction time (years)									
CO_2 emission reduction (%)	90	90	90	50	95	70	99	B	1,9
Space requirement (1000 m^2/MWe)									
Additional data for non thermal plants									
Capacity factor (%), theoretical									
Capacity factor (%), incl. outages									
Ramping configurations									
Ramping (% per minute)	4	4	4					C	3
Minimum load (% of full load)	30	30	30					D	3
Warm start-up time (hours)	4	4	4					E	4
Cold start-up time (hours)	12	12	12					E	4
Environment									
PM 2.5 (mg per Nm3)	150	100	100						2,3
SO_2 (degree of desulphuring, %)	97	97	97						2,3
NO_X (g per GJ fuel)	263	263	263						2,3
CH_4 (g per GJ fuel)									
N_2O (g per GJ fuel)									
Financial data									
Nominal investment (M$/MWe)	3.84	3.46	2.77	2.70	4.90	2.00	3.50	F,G,H	5,7,8
- of which equipment	30%	30%	30%	25%	50%	25%	50%		1
- of which installation	70%	70%	70%	50%	75%	50%	75%		1
Fixed O&M ($/MWe/year)	97,000	90,200	72,800	67,000	124,000	50,000	93,000		5,7,8
Variable O&M ($/MWh)	4.50	4.20	3.70	4.20	5.72	2.63	4.70		5,7,8

Based on data in sheet Supercritical coal

References:

1 Global CCS Institute, 2023, Global status of CCS
2 Koornneef J., 2011, Carbon Dioxide Capture and Air Quality
3 Danish Energy Agency, Technology data - Generation of electricity and district heating, 2020
4 IEAGHG, Operating Flexibility of Power Plants with CCS
5 IEA, 2021, The Role of Low-Carbon Fuels in the Clean Energy Transitions of the Power Sector
6 Danish Energy Agency, Technology Data for Carbon Capture, Transport and Storage, 2023
7 UK BEIS, Assessing the Cost Reduction Potential and Competitiveness of Novel UK Carbon Capture Technology, 2018
8 NREL Annual Technology Baseline 2023, https://atb.nrel.gov/electricity/2023/data
9 IRENA, Reaching Zero with Renewables Capturing Carbon, 2021

Notes:

A The technology Supercritical CCS: Supercritical: solvent-based post combustion CO2 capture (PCCC) designed for 95% capture. The difference in ouput power represents the additional power required by the auxiliary equipment (with CCS, ~15% of the net output).
B This figure represents the efficiency of the capture process. New technologies might remove CO2 more efficiently in the future. CO2 can be already captured at higher rates, but costs to marginally increase capture rates beyond the reported values are relatively high.
C In principle, ramping is not affected by the presence/absence of CCS.
D Minimum load is not affected by CCS. However, the CO2 compressor requires higher loads for smooth operability.
E The regeneration in the post-combustion unit has a start-up time comparable to that of the power plant.
F The total installed capacity of the newly built Super Critical coal plant with CCS is 600 MW.
G The nominal investment cost corresponds to the cost of developing a newbuild supercritical plant with CCS facilty. The nominal investment is based on the economy of scale equation, C1/C2 = (P1/P2)^a, assuming the proportionality factor (a) is 0.6
H The forecasted price are calculated considering the average development rates for the CCS technologies in the NREL ATB 2023

Technology

Technology	Coal, Integrated Gasification Combined Cycle IGCC with CCS, new plant								
	2023	2030	2050	Uncertainty (2023)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	186	186	186					A	1
Generating capacity for total power plant (MWe)	534	534	534					A,E	1
Electricity efficiency, net (%), name plate	33	34	36					A	1,9
Electricity efficiency, net (%), annual average	31	32	34					A	1,9
Forced outage (%)	12	12	12						
Planned outage (weeks per year)									
Technical lifetime (years)	-								
Construction time (years)									
CO_2 emission reduction (%)	90	90	90	50	95	70	99	B	1,9
Space requirement (1000 m^2/MWe)	-	-	-	-	-	-	-		
Additional data for non thermal plants									
Capacity factor (%), theoretical	-	-	-	-	-	-	-		
Capacity factor (%), incl. outages	-	-	-	-	-	-	-		
Ramping configurations									
Ramping (% per minute)	3	3	3					C	4
Minimum load (% of full load)	50	50	50					D	4
Warm start-up time (hours)	6	6	6						3
Cold start-up time (hours)	50	50	50	15	80	15	80		3,5
Environment									
PM 2.5 (mg per Nm3)	115	115	115						2,4
SO_2 (degree of desulphuring, %)	99	99	99						2,4
NO_X (g per GJ fuel)	173	173	173						2,4
CO (g per GJ fuel)									
Financial data									
Nominal investment (M$/MWe)	4.77	4.29	3.43	3.50	6.50	2.50	4.70	E,F,G	5,7,8
- of which equipment	30%	30%	30%	25%	50%	25%	50%		1
- of which installation	70%	70%	70%	50%	75%	50%	75%		1
Fixed O&M ($/MWe/year)	123,000	121,800	116,900	91,000	213,000	87,000	202,000		5,7,8
Variable O&M ($/MWh)	22.00	21.78	21.12	21.56	22.44	20.70	21.54		5,7,8

Based on data in sheet IGCC (Coal)

References:

1 Global CCS Institute, 2023, Global status of CCS
2 Koornneef J., 2011, Carbon Dioxide Capture and Air Quality
3 IEAGHG, Operating Flexibility of Power Plants with CCS
4 Danish Energy Agency, Technology data - Generation of electricity and district heating, 2020
5 IEA, 2021, The Role of Low-Carbon Fuels in the Clean Energy Transitions of the Power Sector
6 Danish Energy Agency, Technology Data for Carbon Capture, Transport and Storage, 2023
7 UK BEIS, Assessing the Cost Reduction Potential and Competitiveness of Novel UK Casrbon Capture Technology, 2018
8 NREL Annual Technology Baseline 2023, https://atb.nrel.gov/electricity/2023/data
9 IRENA, Reaching Zero with Renewables Capturing Carbon, 2021

Notes:

A The technology IGCC – CCS: SOA - slurry-fed IGCC with water-gas shift two high-hydrogen syngas-fired F-Frame combustion turbine/HRSG trains coupled to a single steam turbine, two-stage selexol acid gas removal system designed for 90% CO2 pre-combustion removal. The difference in ouput power represents the additional power required by the auxiliary equipment (with CCS, ~10-15% of the net output).

B This figure represents the efficiency of the capture process. New technologies might remove CO2 more efficiently in the future. CO2 can be already captured at higher rates, but costs to marginally increase capture rates beyond the reported values are relatively high.

C In principle, ramping is not affected by the presence/absence of CCS.

D Minimum load is not affected by CCS. However, the CO2 compressor requires higher loads for smooth operability.

E The total installed capacity of the newly bulit IGCC-CCS is 600 MW.

F The nominal investment cost corresponds to the cost of developing an entirely new IGCC plant with CCS facility. The nominal investment is based on the economy of scale equation, C1/C2 = (P1/P2)^a, assuming the proportionality factor (a) is 0.6

G The forecasted price are calculated considering the average development rates for the CCS technologies in the NREL ATB 2023

Technology

Technology	Natural Gas Combined Cycle with CCS, new plant								
	2023	2030	2050	Uncertainty (2023)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	93	93	93					A	1
Generating capacity for total power plant (MWe)	372	372	372					A,F	1
Electricity efficiency, net (%), name plate	48	51	52					A	1,9
Electricity efficiency, net (%), annual average	47	50	51					A	1,9
Forced outage (%)	10	10	10						
Planned outage (weeks per year)									
Technical lifetime (years)	-								
Construction time (years)									
CO_2 emission reduction (%)	90	90	90	50	95	70	99	B	1,9
Space requirement (1000 m^2/MWe)									
Additional data for non thermal plants									
Capacity factor (%), theoretical	-	-	-						
Capacity factor (%), incl. outages	-	-	-						
Ramping configurations									
Ramping (% per minute)	20	20	20					C	4
Minimum load (% of full load)	45	45	45					D	4
Warm start-up time (hours)	2	2	2					E	3
Cold start-up time (hours)	4	4	4					E	3
Environment									
PM 2.5 (mg per Nm3)	30	30	30						2,4
SO_2 (degree of desulphuring, %)	99	99	99						2,4
NO_X (g per GJ fuel)	80	80	80						2,4
CH_4 (g per GJ fuel)	-	-	-						
Financial data									
Nominal investment (M$/MWe)	2.39	2.15	1.72	1.30	2.90	1.00	2.10	G,H,I	5,7,8
- of which equipment	40%	40%	40%	30%	60%	30%	60%		1
- of which installation	60%	60%	60%	40%	70%	40%	70%		1
Fixed O&M ($/MWe/year)	59,000	50,200	37,800	31,000	65,000	20,000	42,000		5,6,7
Variable O&M ($/MWh)	4.96	4.36	3.62	4.70	5.10	3.40	3.70		5,6

Based on data in sheet CCGT (GAS)

References:

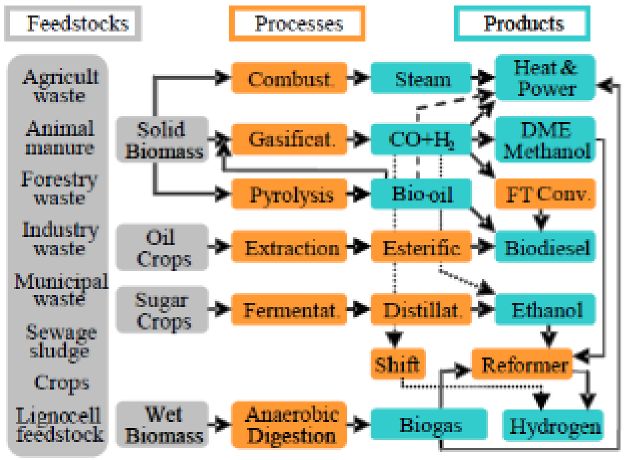
1 Global CCS Institute, 2023, Global status of CCS
2 Koornneef J., 2011, Carbon Dioxide Capture and Air Quality
3 IEAGHG, Operating Flexibility of Power Plants with CCS
4 Danish Energy Agency, 2023, Technology Data – Carbon Capture, Transport and Storage
5 IEA, 2021, The Role of Low-Carbon Fuels in the Clean Energy Transitions of the Power Sector
6 EIA, 2020, Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies
7 Lazard, 2023, LCOE+
8 NREL Annual Technology Baseline 2023, https://atb.nrel.gov/electricity/2023/data
9 IRENA, 2021, Reaching Zero with Renewables Capturing Carbon

Notes:

A The technology CCGT CCS: SOA - solvent-based post combustion CO2 capture (PCCC) designed for 95% capture. The difference in ouput power represents the additional power required by the auxiliary equipment (with CCS, ~10-15% of the net output).
B This figure represents the efficiency of the capture process. New technologies might remove CO2 more efficiently in the future. CO2 can be already captured at higher rates, but costs to marginally increase capture rates beyond the reported values are relatively high.
C In principle, ramping is not affected by the presence/absence of CCS.
D Minimum load is not affected by CCS. However, the CO2 compressor requires higher loads for smooth operability.
E The regeneration in the post-combustion unit has a start-up time comparable to that of the power plant.
F The total installed capacity of the newly bulit CCGT-CCS is 400 MW.
G The nominal investment cost corresponds to the cost of developing a newbuild CCS-CCGT.
H The nominal investment cost for retrofitting corresponds to the cost of retroffiting an existing CCGT with CCS facility. The nominal investment is based on the economy of scale equation, C1/C2 = (P1/P2)^a, assuming the proportionality factor (a) is 0.6
I The forecasted price are calculated considering the average development rates for the CCS technologies in the NREL ATB 2023

15. Biomass Power Plant

Brief technology description
Biomass can be used to produce electricity or fuels for transport, heating and cooking. The figure below shows all products from biomass. This chapter focuses on the solid biomass for combustion to power generation.



Biomass conversion paths (ref. 1)

The technology used to produce electricity in biomass power plants depends on the biomass resources. The electric efficiency is lower because of the lower calorific value of biomass compared to coal and the limitations in steam temperature and pressure due to the mineral contents of the ash – typically 15-35% (ref. 2).

Direct combustion of biomass is generally based on the Rankine cycle, where a steam turbine is employed to drive the generator, similar to a coal fired power plant. A flue gas heat recovery boiler for recovering and pre-heating the steam is sometimes added to the system. This type of system is well developed, and available commercially around the world. Most biomass power plants today are direct fired (ref. 3). In direct combustion, steam is generated in boilers that burn solid biomass, which has been suitably prepared (dried, baled, chipped, formed into pellets or briquettes or otherwise modified to suit the combustion technology) through fuel treatment and a feed-in system. Direct combustion technologies may be divided into fixed bed, fluidized bed, and dust combustion. In dust combustion, the biomass is pulverized or chopped and blown into the furnace, possibly in combination with a fossil fuel (see figure below).

Indonesia has promiment biomass resources which have potential for generation of electricity. The sources include palm oil, sugar cane, rubber, coconut, paddy, corn, cassava, cattle, and municipal waste. According to MEMR (ref. 7), the total biomass potential amounts to almost 33 GW which is widely spread over all islands in Indonesia. The table below show the distribution of biomass potentials. From the 33 GW of biomass potential, about 39% comes from palm oil, 30% from paddy, 9% from rubber, 6% from municipal waste, 5% from corn, 4% from wood, and 4% from sugar cane.

Biomass resources potential (ref. 8)

No	Island	Potential (GW)
1	Sumatera	15.59
2	Jawa Bali Madura	9.22
3	Kalimantan	5.06
4	Sulawesi	1.94
5	Nusa Tenggara	0.64
6	Maluku	0.07
7	Papua	0.15
Total		32.65

Heating values of different biomass fuel types (ref. 9)

Type	LHV (GJ/ton)	Moisture (%)	Ash (%)
Bagasse	7.7 – 8.0	40 – 60	1.7 – 3.8
Cocoa husks	13 – 16	7 – 9	7-14
Coconut shells	18	8	4
Coffee husks	16	10	0.6
Cotton residues			
- Stalks	16	10 – 20	0.1
- Gin trash	14	9	12
Maize			
- Cobs	13 – 15	10 – 20	2
- Stalks			3 – 7
Palm-oil residues			
- Empty fruit bunches	5.0	63	5
- Fibers	11	40	
- Shells	15	15	
Debris	15	15	
Peat	9.0 – 15	13 – 15	1 – 20
Rice husks	13	9	19
Straw	12	10	4.4
Wood	8.4 – 17	10 – 60	0.25 – 1.7

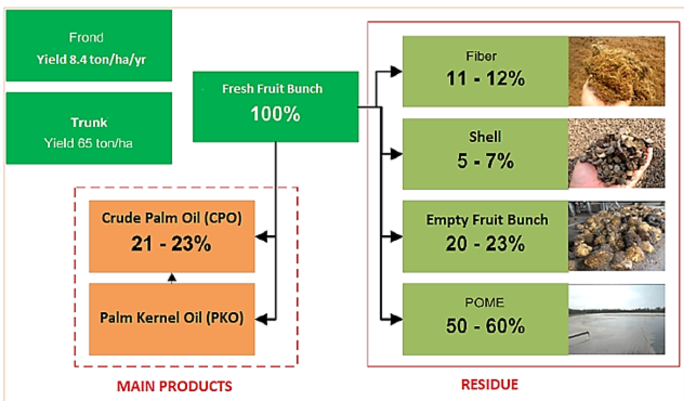
The table above shows that the caloric values of the biomass feedstock range from 5 – 18 GJ/ton, with the palm oil empty fruit brunches (EFB) as the lowest and coconut shells as the highest. The calorific value is highly dependent on the moisture content of the fuel.

Total installed capacity of biomass (including biogas and MSW) power plants in Indonesia for 2019 was 1,889.8 MW (Ministry of Energy and Mineral Resources, 2019). Most of these power plants are operated by industries using various types of biomasses as fuels, such as palm oil EFB (empty fruit bunch), municipal waste, palm oil mill effluent (POME), palm kernel shells (PKS), pulp and paper industry waste, and sugar cane industry waste.

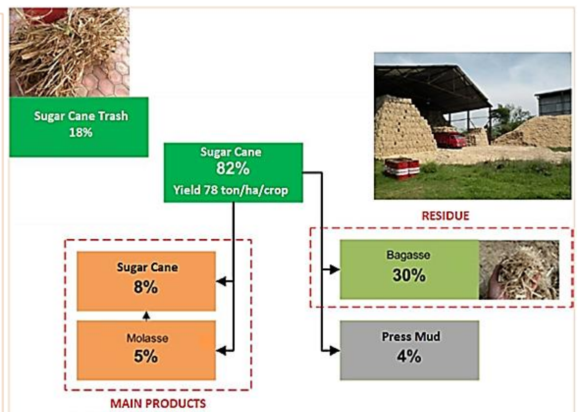
Biomass power plant capacity by waste type. Source: MEMR, 2019

Waste type	Capacity (MW)	Share (%)
Pulp and paper waste	1,243.19	65.8%
Palm oil solid waste	263.41	13.9%
Sugar Cane waste	222.94	11.8%
Palm oil mill effluent (POME)	110.62	5.9%
MSW	15.65	0.8%
Others	34.00	1.8%
Total	1,889.80	

Calculation of biomass raw materials from plantation products can be done using the mass balance approach. The mass balance is of course different for each raw material. The figures below present mass balance for relevant raw materials.



(a)



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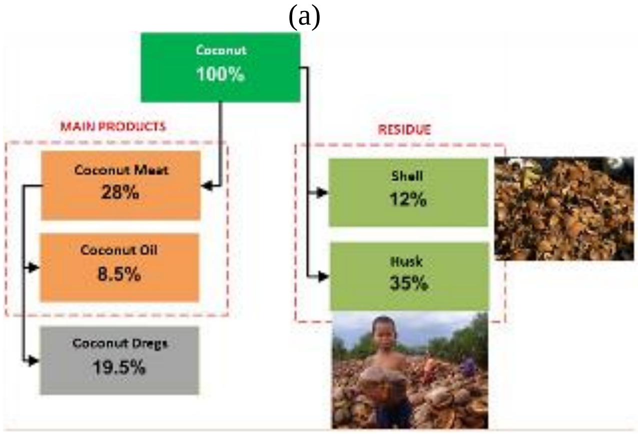

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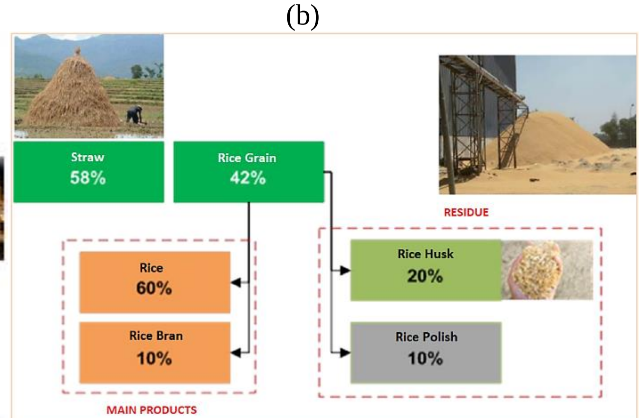

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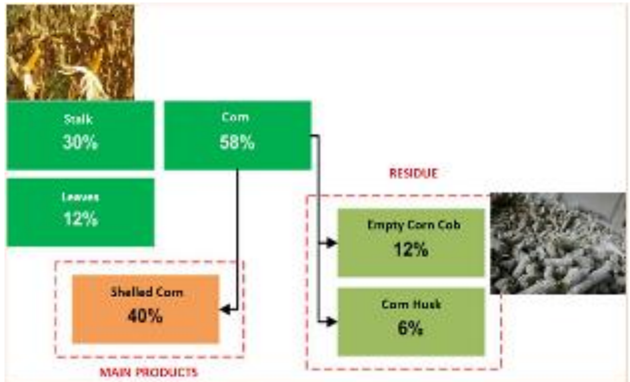


(e)

Mass Balance of (a) Palm Oil, (b) Sugar Cane, (c) Coconut, (d) Rice and (e) Corn (Source: Arief Tajalli, Panduan Penilaian Potensi Biomasa Sebagai Sumber Energi Alternatif di Indonesia, Penabulu Alliance, 2015)

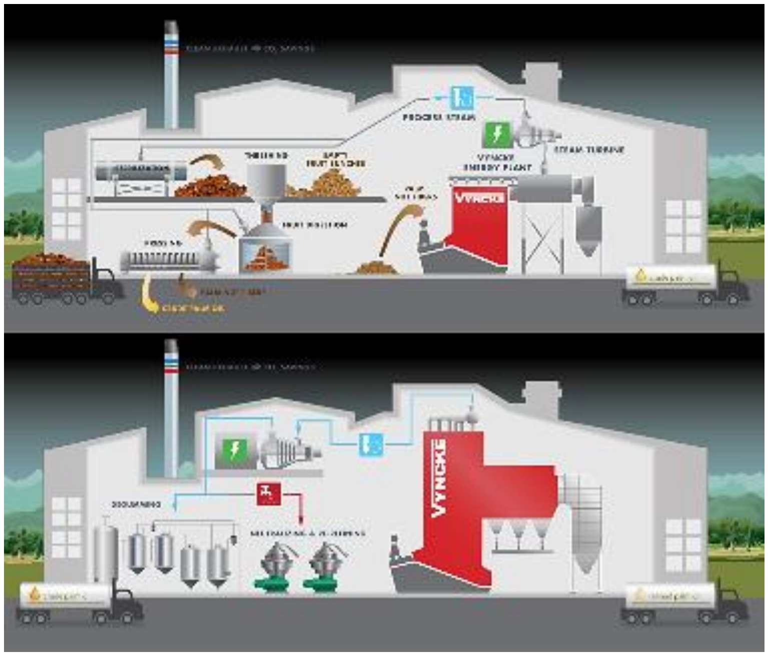
In the following, different uses of biomass feedstocks are presented, with a focus on palm oil residues.

Palm oil residue-based feedstock

Indonesia is the world's biggest producer of palm oil, providing more than half of the world's supply. In 2019, Indonesia produced over 51.8 million tons of palm oil, and exported nearly 69% of it. Oil palm plantations stretch across 14.7 million hectares in the same year. Of that, about 55% of palm plantation areas are owned by private companies. There are several different types of plantations, including small, privately owned plantations, and larger, state- owned plantations. As the most productive source of vegetable oil, 1 hectare of land planted with palm can produce up to 3.5 tonnes of crude palm oil.

According to Statistic Central Agency (2018), there are about 1731 palm oil mills in Indonesia stretch across 25 provinces in Indonesia. Most are located in these provinces: North Sumatera (329 mills), West Kalimantan (319 mills), Riau (196 mills), Central Kalimantan (143 mills) and South Sumatera (133 mills). In terms of production capacity of crude palm oil, the province of Riau has the biggest capacity of 7.59 million tons, followed by Central Kalimantan 5.21, North Sumatera 4.85, South Sumatera 2.99, East Kalimantan 2.54 and West Kalimantan 2.53 million tons. Sumatera and Kalimantan account for 96% of total palm oil production in Indonesia.

Based on the several studies, a palm oil mill with an input capacity of 30 tons of palm fresh fruit bunches per hour can generate around 3 – 4 MW biomass power plant from its solid waste and 1 MW biogas power plant from its effluent waste (POME).



Typical combined heat and power from palm oil solid waste (Source: Vyncke)

Palm-oil based feedstock

Besides being an ingredient for food industries, palm oils are used as feedstock for biodiesel production in Indonesia. Biodiesel is currently produced via the transesterification of triglycerides using alkaline catalyst and short-chain alcohol to form fatty acid methyl esters (FAMEs, also called biodiesel) and glycerol. To fulfil domestic and export demand, Indonesia biodiesel production capacity reached 8.4 million KL in 2019. The characteristics of biodiesel are given in the following table.

Characteristics of Biodiesel.

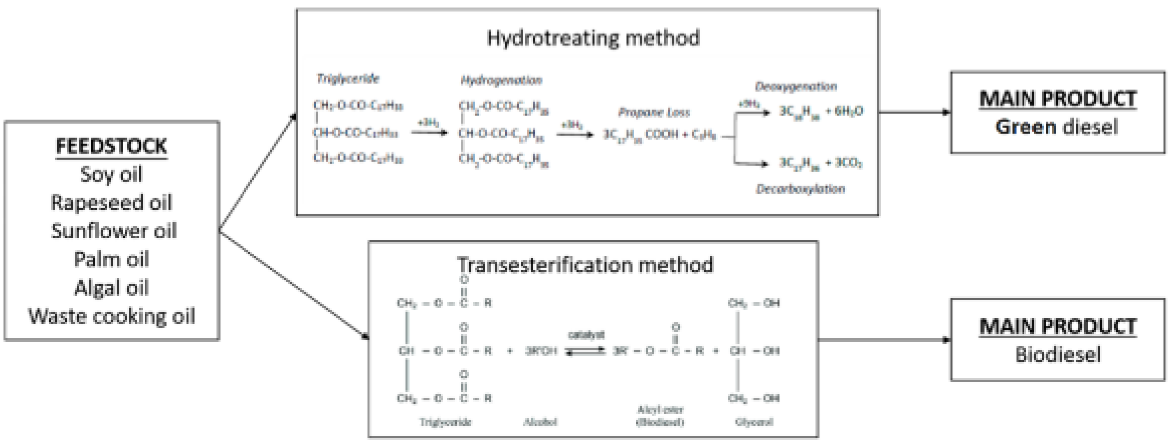
Chemical Nomenclature	Methyl Ester
Cetane Number	54
Density (kg/litre)	0.88
LHV (MJ/kg)	37.3

Source: LAMNET by ETA of Italy, WIP of Germany and EUBIA of Belgium, 2004.

Since 2018, Indonesia has had a mandatory regulation that diesel fuel sold across nation must be blended with 20% FAME which is made from palm oil and called as B20. Last year the Government of Indonesia launched a new policy on mandatory use of B30, which is biodiesel containing 30% palm-based fuel, in all sectors including power generation. This policy started effectively on January 2020. Indonesia is recorded as the first country to implement B30 in the world.

In order to reduce oil imports and current account deficit (CAD), the government has asked state electricity company PLN to convert its diesel-fueled power plants into biodiesel-fueled power plants. PLN responded and reported that the company used 1.64 million KL and 2.16 million KL of B20/B30 in 2018 and 2019 respectively for diesel-fueled power plants. Up to now PLN is still operating a number of diesel engines to supply electricity to some regions particularly outside Jawa and remote areas. Total installed capacity of diesel engine power plants owned by PLN is 4,781 MW as of April 2020. For these plants PLN consumed 2.68 million oil-based fuel in 2019, including biodiesel. Currently PLN has a program to transform its diesel-fueled power plants into 100% palm-oil-based power plants. This program will take about two years. Last year PLN succeeded in transforming one of PLN diesel-fueled power plant at Belitung Island with capacity of 5 MW into a 100% palm-oil-based power plant.

State oil company Pertamina is developing two "biorefineries" in Cilacap of Central Jawa and Plaju of Sumatera with an output capacity of 6,000 bpd (barrels-per-day) and 20,000 bpd respectively to produce green diesel and green jet kerosene fuel made from 100% palm oil. These green fuels (or renewable fuels) are produced through processing 100% RBDPO (Refined, Bleached and Deodorized Palm Oil) straight into its refineries using catalytic cracking and hydrogen gas. This is different from the biodiesel resulted from a transesterification process. Being processed in the refinery using fractional distillation, the quality of green fuel is much better than petroleum products and biodiesel in terms of less emission and higher cetane number (75 – 85). Green diesel is chemically the same as petroleum diesel, but it outperforms petroleum diesel due to its composition and purity. Every part of green diesel can be found in petroleum diesel, but the impurities and contaminants that can come with petroleum diesel are eliminated from green diesel.

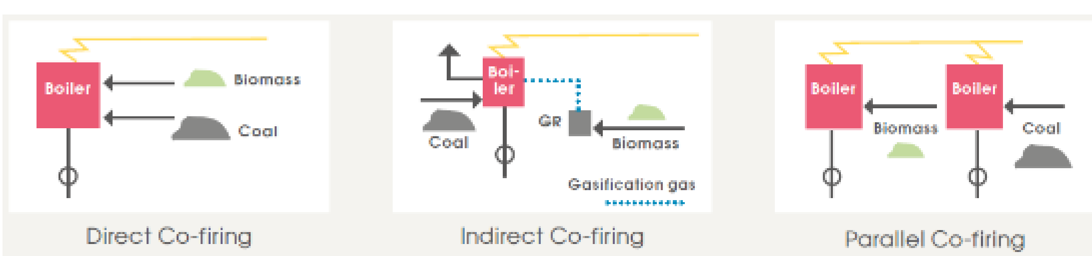


Biofuel process from vegetable oils

Saifuddin Nomanbhay, Mei Yin Ong, Kit Wayne Chew, Pau-Loke Show, Man Kee Lam and Wei-Hsin Chen, Organic Carbonate Production Utilizing Crude Glycerol Derived as By-Product of Biodiesel Production: A Review, Journal of Energies, Volume 13 Issue, MDPI, 2020).

Co-firing with coal

There are three possible technology set-ups for co-firing coal and biomass: direct, indirect and parallel co-firing (see figure below). Technically, it is possible to co-fire up to about 20% biomass capacity without any technological modifications; however, most existing co-firing plants use up to about 10% biomass. The co-firing mix also depends on the type of boiler available. In general, fluidized bed boilers can substitute higher levels of biomass than pulverized coal-fired or grate-fired boilers. Dedicated biomass co-firing plants can run up to 100% biomass at times: this is relevant for plants that are seasonally supplied with large quantities of biomass (ref. 5).



Different biomass co-firing configurations (ref. 6).

Combustion can in general be applied for biomass feedstock with moisture contents between 20 – 60% depending on the type of biomass feedstock and combustion technology.

In the direct co-firing, bio pellets are blended through the grinding equipment and the same or separate feeder. Then, they are mixed with coal into the same boiler to be burned. Generally, there is no, or limited, investment cost for special equipment with this method. This co-firing method is mostly adopted by pulverized coal boilers.

The indirect co-firing method requires additional equipment such as a gasifier for pre-processing the biomass. The biomass is gasified into syngas in a gasifier before finally entering the coal boiler for combustion. This allows better fuel flexibility than direct co-firing and potentially high co-firing rates. The requirements to the producer gas quality (heating value, tar and particles content) are lower compared to other types of applications, such as gas engines or gas turbines (ref. 14).

The parallel co-firing requires an investment for separate bio-pellet or biomass fired boiler. The resulting steam from the biomass fired boiler is fed into the existing coal fired steam boiler system. This approach uses separate biomass fired boiler which allows maximum biomass utilization. This method is usually used on paper mills by using bark or wood waste.

Bio pellets are an ideal fuel for co-firing coal fired power plants. As a densified, low-moisture, uniform biomass fuel, pellets avoid many challenges associated with raw biomass. Bio pellets have many parameters comparable to coal making them a compatible co-firing fuel.

Bio pellets and coal property comparison. Source: PT. Pembangkitan Jawa Bali, PLN, 2020.

Parameter	Unit	High Volatile B Bituminous	High Volatile C Bituminous	Wood Pellet	Palm Kernel Shell
		Ar	Ar	Ar	Ar
Ultimate					
Carbon	%	48.61	43.82	47.67	47.62
Hydrogen	%	3.75	3.37	1.71	5.14
Nitrogen	%	1.09	0.68	0.17	0.26
Sulphur	%	0.63	0.11	0.05	0.05
Oxygen	%	13.95	13.22	35.37	35.87
Proximate					
Total Moisture	%	24.32	35.84	10.11	9.91
Ash content	%	7.66	2.96	1.91	1.16
Volatile matter	%	34.43	30.97	71.61	70.37
Fixed carbon	%	33.59	30.24	16.37	18.56
Total sulphur	%	0.63	0.11	0.05	0.05
Gross calorific value	kCal/kg	4897	4199	4276	4563
Hardgrove Grindability Index	-	47	55	< 32.00	< 32
Bulk Density	kg/m3	900	890	571	409

Palm kernel shells and wood pellets.

Input

Biomass, e.g. residues from industries (wood waste, empty fruit bunches, coconut shell, etc.), wood chips (from pulpwood, logging residues etc. collected in forests), straw, and energy crops.

Wood is usually the most favourable biomass for combustion due to its low content of ash and nitrogen. Herbaceous biomass like straw and miscanthus have higher contents of N, S, K, Cl etc. that leads to higher primary emissions of NOx and particulates, increased ash, corrosion and slag deposits. Flue gas cleaning systems as ammonia injection (SNCR), lime injection, back filters, DeNOx catalysts etc. can be applied for further reductions of emissions.

Other exotic biomasses as empty fruit bunch pellets (EFB) and palm kernel shells (PKS) are available in the local market.

Output

Electricity (and heat if there is demand for it).

Typical capacities

Large: bigger than 50 MWe
Medium: 10 – 50 MWe.
Small: 1 – 10 MWe.

Ramping configuration

The plants can be ramped up and down. Medium and small size biomass plants with drum type boilers can be operated in the range from 40-100% load. Often plants are equipped with heat accumulators allowing the plant to be stopped daily.

Advantages/disadvantages

Advantages:

- Mature and well-known technology.
- CO_2 emissions are considered neutral when biomass is sourced sustainably as described in ***Environment***.
- Using biomass waste will usually be cheap.

Disadvantages:

- The availability of biomass feedstock is location-dependent.
- Use of biomass can have negative indirect consequences e.g. in competition with food production, nature/biodiversity.
- Biomass is a limited resource and power production is in competition with other uses, e.g. transport, industry, local heating and cooking.

- In the low-capacity range (less than 10 MW) the scale of economics is quite considerable.
- When burning biomass in a boiler, the chlorine and sulfur in the fuel end up in the combustion gas and erode the boiler walls and other equipment. This can lead to the failure of boiler tubes and other equipment, and the plant must be shut down to repair the boiler.
- Fly ash may stick to boiler tubes, which will also lower the boiler's efficiency and may lead to boiler tube failure. With furnace temperatures above 1000°C, empty fruit bunches, cane trash, and palm shells create more melting ashes than other biomass fuels. The level for fused ash should be no more than 15% in order to keep the boiler from being damaged (ref. 9).
- Combustion of biomass results in emissions of SO_2, NO_x and particles.

Environment

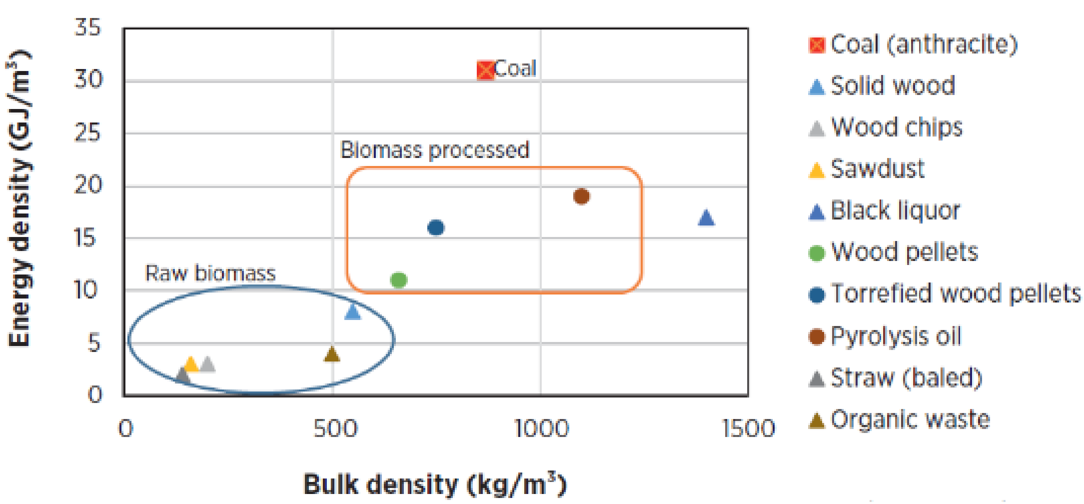
The main ecological footprints from biomass combustion are persistent toxicity, climate change, and acidification. However, the footprints are small, particularly when only biomass residues, are used for combustion (ref. 10). The combustion of biomass from dedicated plantations can only be considered carbon neutral if the energy crops harvested to supply the bioenergy grow back and keep that carbon sequestered in biomass and soils.

Research and development

Biomass power plants are a mature technology with limited development potential (category 4). However, in Indonesia, using biomass for power generation is relatively new.

Some 85% of biomass energy is consumed in Indonesia for traditional uses, for example cooking with very low efficiency (10%-20%) while modern uses of biomass for heat and power generation include mainly high-efficiency, direct biomass combustion, co-firing with coal and biomass gasification. These modern uses, especially direct combustion, are increasing in Indonesia now. Solid and liquid palm oil wastes seem to be the most favourable choices for biomass feedstock due to the easy access and handling and also the availability.

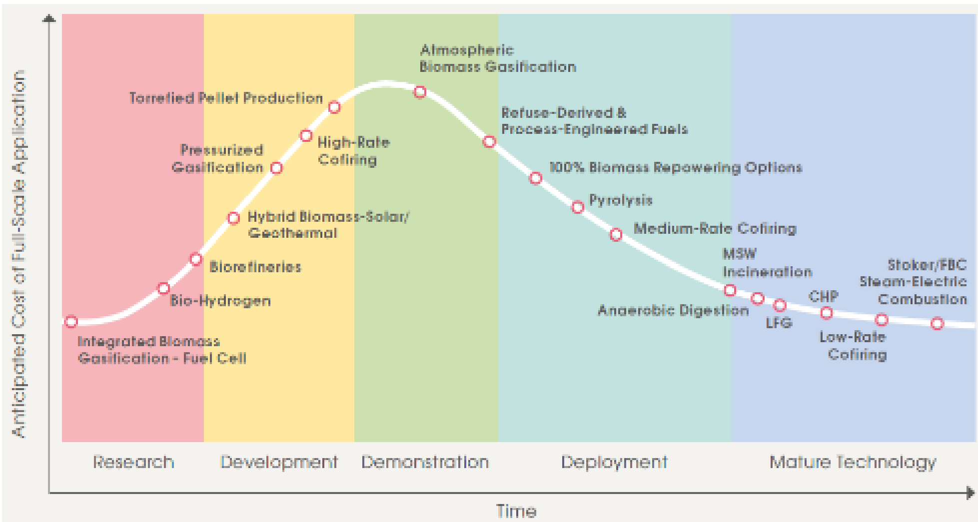
Direct, traditional uses of biomass for heating and cooking applications rely on a wide range of feedstock and simple devices, but the energy efficiency of these applications is very low because of biomass moisture content, low energy density, and the heterogeneity of the basic input. A range of pre-treatment and upgrading technologies have been developed in order to improve biomass characteristics and make handling, transport, and conversion processes more efficient and cost effective. Most common forms of pre-treatment include drying, pelletization and briquetting, torrefaction and pyrolysis, where the first two are by far the most commonly used.



Energy density of biomass and coal (ref. 11).

MSW incineration, anaerobic digestion, landfill gas, combined heat and power and combustion are examples of biomass power generation technologies which are already mature and economically viable. Biomass gasification and pyrolysis are some of the technologies which are likely to be developed commercially in the future.

Gasifier technologies offer the possibility of converting biomass into a producer gas, which can be burned in simple or combined-cycle gas turbines at higher efficiencies than the combustion of biomass to drive a steam turbine. Although gasification technologies are commercially available, more needs to be done in terms of R&D and demonstration to promote their widespread commercial use.



Biomass power generation technology maturity status (ref. 12).

Biomass pyrolysis is the thermal decomposition of biomass in the absence of oxygen. The products of decomposition are solid char, a liquid known as bio-oil or pyrolysis oil, and a mixture of combustible gases. The relative proportions of solid, liquid and gaseous products are controlled by process temperature and residence time, as indicated in the table below.

Bio-oil has a lower heating value of about 16 MJ/kg and can after suitable upgrading be used as fuel in boilers, diesel engines and gas turbines for electricity or CHP generation. As a liquid with higher energy density than the solid biomass from which it is derived, bio-oil provides a means of increasing convenience and decreasing costs of biomass transport, storage and handling.

Phase makeup of biomass pyrolysis products for different operational modes (ref. 13).

Mode	Conditions	Composition		
		Liquid	Char	Gas
Fast pyrolysis	Moderate temperature, short residence time	75%	12%	13%
Carbonization	Low temperature, very long residence time	30%	35%	35%
Gasification	High temperature, long residence time	5%	10%	85%

The Association of Southeast Asian Nations (ASEAN) has analysed investment costs for biomass (Ref. 15) in Indonesia, Malaysia and Thailand. While several smaller units had investment costs of US$$_{2016}$ 2.5/W, a 15 MW Indonesian unit had much lower costs of US$$_{2014}$ 0.6/W.

According to the draft National Biomass Power Development Report prepared by the Institute of Energy in 2018, it is estimated that by 2025, the total energy theory of biomass resources will reach 130.59 million tons (equivalent to 454.89 million MWh) and in 2030 will reach 138.41 million tons (equivalent to 483.16 million MWh). Source agriculture still uses a large proportion of about 67%, followed by solar wood with about 30%, the rest is waste wood with about 3%.

Investment cost estimation

The investment costs of biomass power plants largely depend on the type of feedstock – size, calorific value, chemical composition etc., as this affects the pre-treatment processes. Economy of scale also plays an important role, as biomass plants in Indonesia are relatively small, operate in condensing mode and display a lower efficiency compared to international standards. Recent auction and tariff data suggest investment cost figures of around 2.0 MUSD/MW.

Investment costs [MUSD$_{2022}$/MW]		**2020**	**2023**	**2030**	**2050**
Catalogues	**New Catalogue (2023)**		**2.28**	**2.07**	**1.82**
	Existing Catalogue (2020)	2.28		2.08	1.83
Indonesia data	PPA data[1]	2.34			
	Feed-in Tariff, own calculation[2]		1.51 - 2.25*		
	ESDM[3]				
	IRENA (Other Asia)[4]	1.77			
International data	NREL ATB		4.56	4.39	3.93
	IEA Bioenergy (Task 32)		3.08	2.97	2.97
Projection	Development – cost trend [%]	-	100%	91%	80%

[1]*PPA results signed in 2018 with COD 2018-2019 as summarized in the presentation by Ignasius Jonan in "Renewable Energy for Sustainable Development" (Bali, 12 Sept 2018).*

[2]*FIT levels proposed by ESDM in the draft PERPRES Harga Listrik EBT. Back calculation of CAPEX based on a WACC of 12%.*

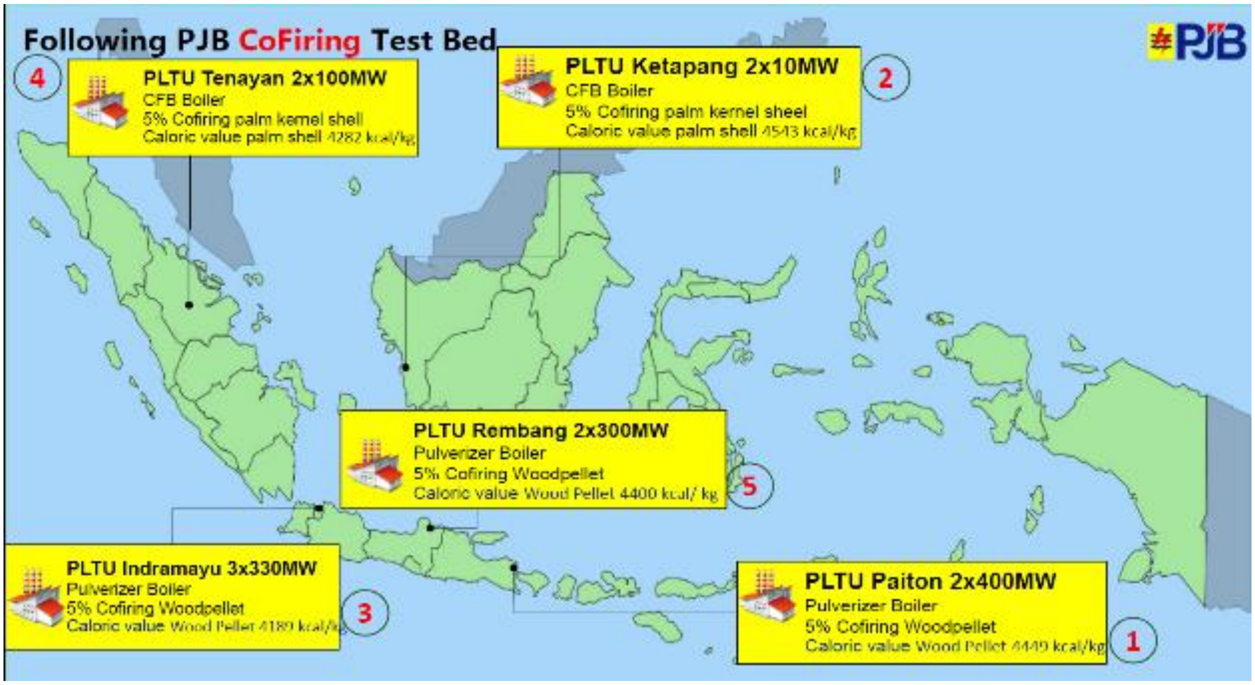
[3]*ESDM presentation on "KATADATA Shifting Paradigm: Transition towards sustainable energy". Sampe L. Purba (26 August 2020)*

[4]*IRENA. "Renewable Power Generation Cost in 2019". Cost of investment in Indonesia in 2019 (excluding margins and financing cost).*

** Considering fuel cost in the range 2-3 USD/GJ*

Examples of current projects

PLN has commenced a program called "Green Booster". One of its strategies is co-firing all PLN coal power plants with biomass or waste. In 2019, PLN succeeded in conducting co-firing on some small and medium capacity coal power (see figure below). Following this success, PLN will implement co-firing with biomass on several larger coal power plants comprising PLTU Suralaya, PLTU Pelabuhan Ratu, PLTU Adipala, PLTU Suralaya 8, PLTU Labuan, PLTU Paiton 1 and 2.



Co-firing projects of PT Pembangkitan Jawa Bali, PLN in 2019 and 2020

The proportion of biomass for co-firing coal power plants will be gradually increased from 1% to 5%. This is equivalent to approximately 202 MW - 1,010 MW of current total PLN coal power plant installed capacity.

In 2018, PLN agreed to buy electricity from the first IPP biomass power plant at Siantan, West Kalimantan. The plant has a capacity of 15 MW. The feedstock is from solid waste, such as palm kernel shells, palm fiber and empty fruit bunches of a palm oil plantation owned by PT Rezeki Perkasa Sejahtera Lestari, which is also the owner of the biomass power plant. It uses gasification technology. The total investment cost for the project is 290 billion rupiahs or equivalent to 20.7 million USD. Under PPA contract, the company sells the electricity to PLN at a price of 1,495 rupiahs/kWh or 10.7 US cents/kWh.

An innovation in biomass power plant design is a bamboo-based biomass power plant with capacity of 700 kW at Mentawai that was inaugurated in 2019. This plant was a grant from Millenium Challenge Corporation of USA. By collaborating with PLN, all electricity produced will be delivered to households.

Another new biomass power plant that is expected to be online this year is rice husk-based biomass power plant at Ogan Ilir, South Sumatera. This is the first commercial scale biomass power plant in Indonesia that uses rice husk as feedstock. It has an installed capacity of 3 MW. The company, PT Buyung Poetra Sembada who owned this plant, has 200 hectares of rice field to guarantee the continuity of rice husk supply. The company spent 70 billion rupiahs or 4.83 million USD to build this plant. The electricity produced from the plant of about 2.5 MW will be used as power supply for the rice mill. The excess power will be sold to PLN.

PLTBm Siantan (ref 15)
This PLTBm has a capacity factor of more than 85%, or nearly 7,500 hours per year, is not intermittent (pauses), and may be utilized as a base load, producing 75,000,000 kWh of clean energy, or the equivalent of 25,000 tons of CO2, and using combustion ash as fertilizer.

The power generated by the Siantan PLTBm will eventually be distributed to the Equatorial System via PLN's 20 kilovolt (kV) network, which extends 5.6 circuit kilometers (km) from the Siantan Main Substation (GI) interconnection point. With an average capacity of 341 MW and an average peak load of 294 MW, the Khatulistiwa System now serves PLN customers in Pontianak, Kubu Raya, Mempawah, Singkawang, Pemangkat, Sambas, and Bengkayang. On September 5, 2016, the Electricity Sales and Purchase Agreement (PJBL) was signed between PT REZEKI Perkasa Sejahtera Lestari, the developer of the Siantan PLTBm, and PT PLN (Persero).

PLTBm Bambu Siberut (ref 16)

The first bamboo-fueled biomass power plant (PLTBm) in Indonesia was successfully built to replace the 1,300 kW diesel power plant (PLTD) that had been running on Siberut Island. PLTBm was developed in three villages on Siberut Island, Mentawai Islands, West Sumatra, namely Saliguma, Madobag, and Matotonan, with a total capacity of 700 kW to supply light for 1,233 heads of families (KK).

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Data sheets

The following pages contain the data sheets of the technology. All costs are stated in U.S. dollars (USD), price year 2022. The uncertainty is related to the specific parameters and cannot be read vertically – meaning a product with e.g. lower efficiency does not have a lower price.

The data sheet describes plants used for production of electricity. These data do not apply for industrial plants, which typically deliver heat at higher temperatures than power generation plants, and therefore they have lower electricity efficiencies. Also, industrial plants are often cheaper in initial investment and O&M, among others because they are designed for shorter technical lifetimes, with less redundancy, low-cost buildings etc.

Technology

Technology	Biomass power plant (small plant - palm oil / rice husk)								
	2023	2030	2050	Uncertainty (2023)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	25	25	25	1	50	1	50		1,5
Generating capacity for total power plant (MWe)	25	25	25	1	50	1	50		1,5
Electricity efficiency, net (%), name plate	32	32	32	25	35	25	35		1,3,7
Electricity efficiency, net (%), annual average	31	31	31	25	35	25	35		1,3,7
Forced outage (%)	7.0	7.0	7.0	5.3	8.8	5.3	8.8	A	1
Planned outage (weeks per year)	6.0	6.0	6.0	4.5	7.5	4.5	7.5	A	1
Technical lifetime (years)	25	25	25	19	31	19	31	A	8,10
Construction time (years)	2.0	2.0	2.0	1.5	2.5	1.5	2.5	A	10
Space requirement (1000 m^2/MWe)	35	35	35	26	44	26	44	A	1,9
Additional data for non thermal plants									
Capacity factor (%), theoretical	-	-	-	-	-	-	-		
Capacity factor (%), incl. outages	-	-	-	-	-	-	-		
Ramping configurations									
Ramping (% per minute)	10	10	10						3
Minimum load (% of full load)	30	30	30						3
Warm start-up time (hours)	0.5	0.5	0.5						3
Cold start-up time (hours)	10	10	10						3
Environment									
PM 2.5 (mg per Nm^3)	12.5	12.5	12.5						3
SO_2 (degree of desulphuring, %)	0	0	0						3
NO_X (g per GJ fuel)	125	125	125						3
CH_4 (g per GJ fuel)	0.9	0.9	0.9						3
N_2O (g per GJ fuel)	1.1	1.1	1.1						3
Financial data									
Nominal investment (M$/MWe)	2.28	2.07	1.82	1.48	2.57	1.50	2.60	B,C	1,4-8,11
- of which equipment	65%	65%	65%	50%	85%	50%	85%		1,2
- of which installation	35%	35%	35%	15%	50%	15%	15%		1,2
Fixed O&M ($/MWe/year)	54,000	49,700	43,200	43,000	72,000	36,500	61,000	A	4,5,8,11
Variable O&M ($/MWh)	3.40	3.13	2.72	2.80	4.60	2.40	3.90	A	5,11
Start-up costs ($/MWe/start-up)									

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11 Learning curve approach for the development of financial parameters.

Notes:

A Uncertainty (Upper/Lower) is estimated as +/- 25%.

B Investment cost include the engineering, procurement and construction (EPC) cost. See description under Methodology.

C For 2023, uncertainty ranges are based on cost spans of various sources. For 2050, the values as calcuated in the previous version are used, where we combined the base uncertainity in 2023 with an additional uncertainty span based on learning rates variying between 10-15% and capacity deployment from Stated Policies and Sustainable Development scenarios separately.

D The boiler in the plant is a suspension fired boiler producing steam to be used in a subsequent back pressure steam turbine. It is possible to pulverize wood pellets and use it for suspension firing but it has not been possible to find an appropriate reference.

16. Municipal Solid Waste and Landfill Gas Power Plants

Brief technology description

Municipal solid waste (MSW) is a waste type consisting of everyday items that are discarded by the public. The composition of MSW varies greatly from municipality to municipality, and it changes significantly with time. The MSW industry has four components: recycling, composting, disposal, and waste-to-energy. MSW can be used to generate energy. Several technologies have been developed that make the processing of MSW for energy generation cleaner and more economically viable than ever before, including landfill gas capture, combustion, pyrolysis, gasification, and plasma arc gasification (ref. 1). While older waste incineration plants emitted a lot of pollutants, recent regulatory changes and new technologies have significantly reduced this concern. This chapter concentrates on incineration plants and landfill gas power plants.

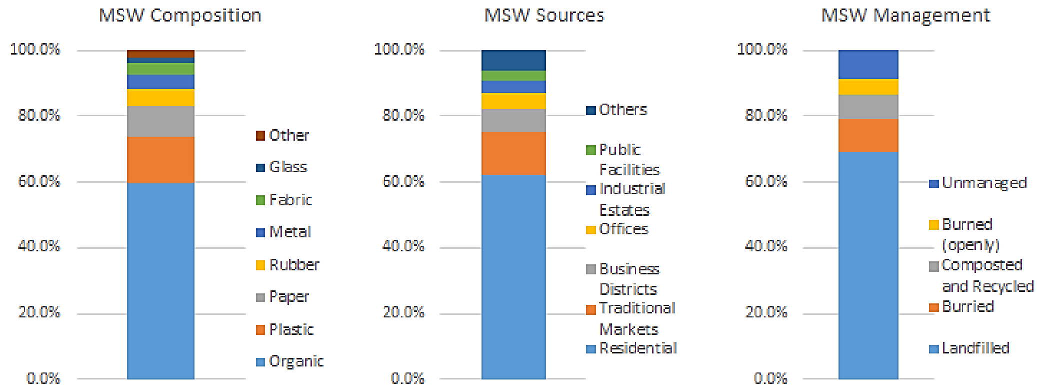
About 67.8 million tons of urban solid waste were produced in Indonesia in 2019 (Ministry of Environment and Forestry, 2020), which is straining the country's existing waste management infrastructure. More than two-thirds of this waste stream is disposed in the country's approximately 521 open landfill sites, several of which are approaching their maximum capacity. The remainder is predominantly buried, burned, composted or remains unmanaged. For an overview of different landfill site types, see the table below.

Type of Landfill	Number of Landfills	Area of Landfills (ha)
Open dump	445	1,433
Controlled landfill	52	483
Sanitary landfill	24	182
Total	521	2,098

Source: MEMR (2020), Waste to Energy Guidebook.

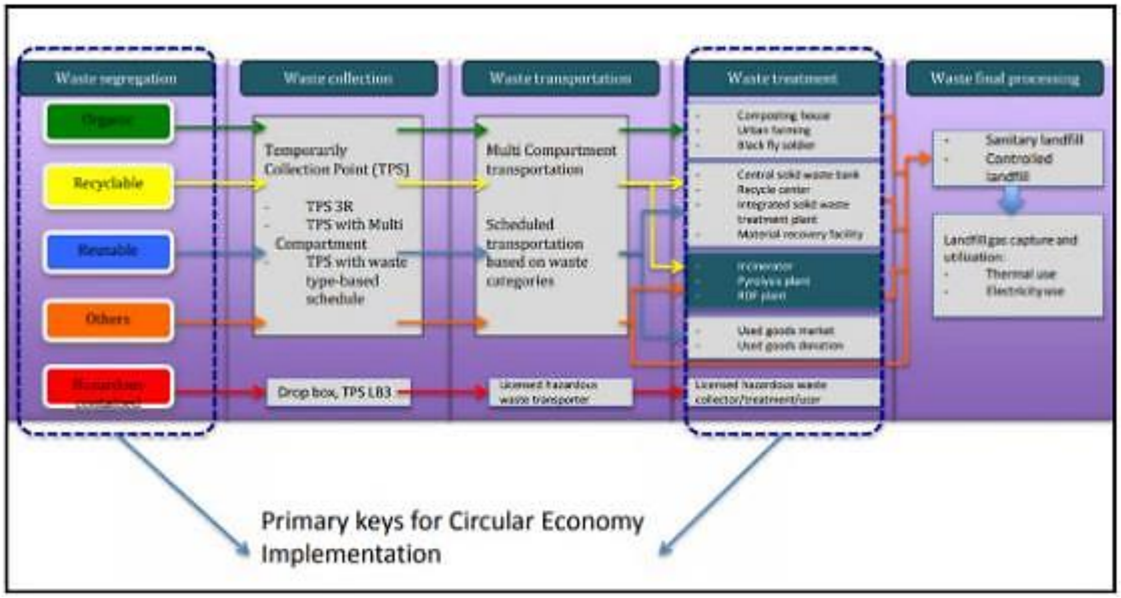
The first sanitary landfill in Indonesia at Bangli, Bali (Source: MEMR (2020), Waste to Energy Guidebook).

The figure below summarizes Indonesia's MSW composition, source and handling methods from left to right.



Indonesia's Municipal Solid Waste composition, source and handling statistics (Ministry of Environment and Forestry, 2017).

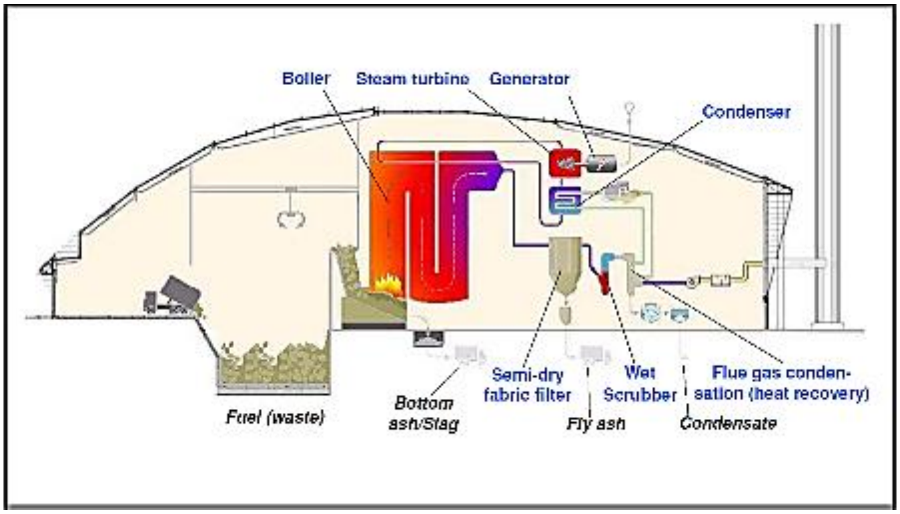
Based on solid waste management national policy and strategy target 2017–2025, Indonesia have a target to reduce to 30% and properly handle 70% of all waste before 2025. It is projected that waste generation in 2025 will be 70.8 million tons. Of that 70% will be handled by applying Circular Economy concept which is consists of waste reduction and waste handling policies so the waste volume will be 30% left.



Business Process of Waste Handling

Incineration power plants

The major components of waste to energy (WtE) incineration power plants are: a waste reception area, a feeding system, a grate fired furnace interconnected with a steam boiler, a steam turbine, a generator, an extensive flue gas cleaning system and systems for handling of combustion and flue gas treatment residues (see the schematic below).



Typical Waste to Energy Plant (Nordic Heat of Sweden, 2017)

The method of using incineration to convert municipal solid waste to energy is a relatively old method of WtE production. The waste is delivered by trucks and is normally incinerated in the state in which it arrives. Only bulky items are shredded before being fed into the waste bunker. Incineration generally entails burning waste (residual MSW, commercial, industrial, and refuse-derived fuel) to boil water, which powers steam generators that make electric energy and heat to be used in homes, businesses, institutions and industries. One problem associated with incinerating MSW to make electrical energy is the potential for pollutants to enter the atmosphere with the flue gases from the boiler. These pollutants can be acidic and were in the 1980s reported to cause environmental damage by turning rain into acid rain. Since then, the industry has removed this problem by the use of lime scrubbers and electro-static precipitators on smokestacks. By passing the smoke through the basic lime scrubbers, any acids that might be in the smoke are neutralized, which prevents the acid from reaching the atmosphere and hurting the environment. Many other devices, such as fabric filters, reactors, and catalysts destroy or capture other regulated pollutants.

According to Ministry of MEMR, total potential of Waste to Energy power generation in Indonesia is 2,066 MW. Of that, Indonesia now has 9 MW installed capacity of Waste to Energy using combustion technology which will be in operation this year. The calorific value of MSW depends on the composition of the waste. Next table gives the estimated calorific (or heating) value of MSW components on a dry-weight basis.

Average heating values of MSW components (ref. 2)

Component	**Heating Value (GJ/ton)**
Food Waste	4.7
Paper	16.8
Cardboard	16.3
Plastics	32.6
Textiles	17.5
Rubber	23.3
Leather	1.7
Garden trimmings	6.5
Wood	18.6

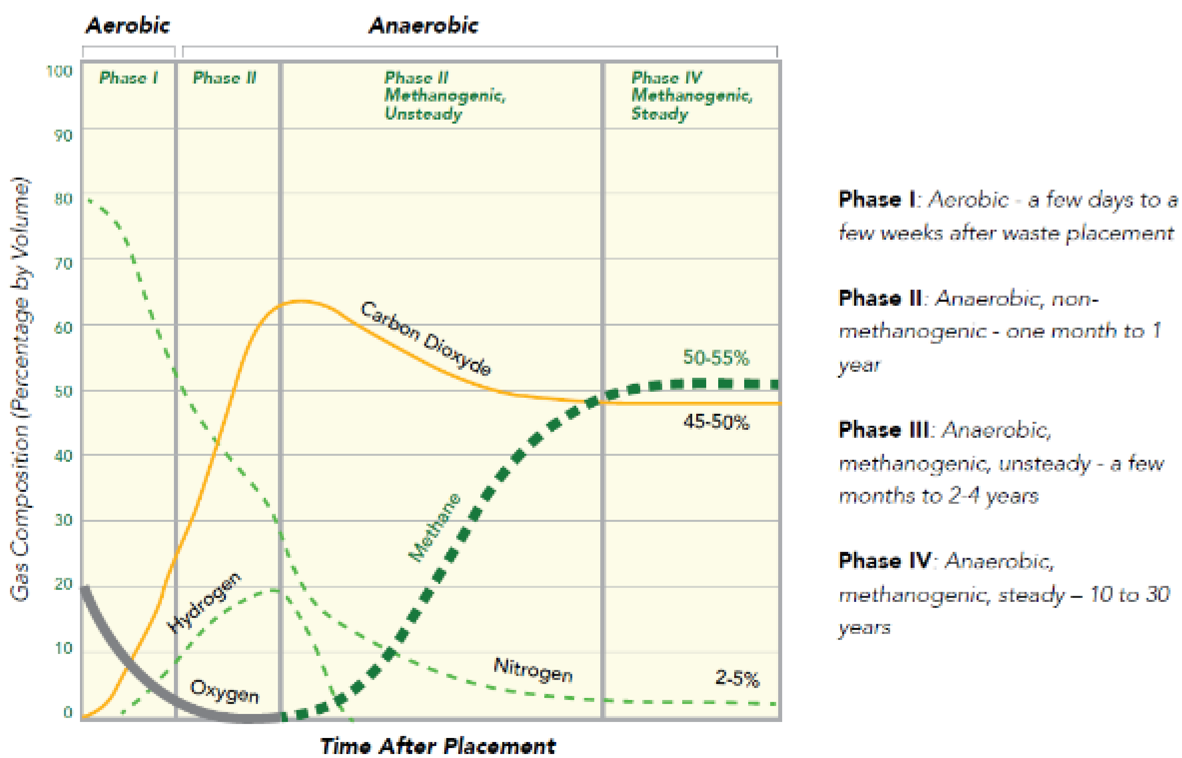
Glass	0.1
Metals	0.7

The potential to utilise waste in WtE plants is influenced by the density of the waste, its moisture and ash content, its heating value and particle size distribution. Thermal WtE technology feedstock is dependent on its chemical content (carbon, hydrogen, oxygen, nitrogen, sulphur and phosphorous) and its volatile content. Typically, waste with a calorific value greater than 1,400 kcal/kg is suitable for thermal WtE feedstock. On average, 0.45 kg of municipal solid waste has the potential to produce an average heating value of 5,100 BTUs. However, this depends on the form of the waste and level of processing required (Source: MEMR (2020), Waste to Energy Guidebook).

Typical electric efficiencies of waste-to-energy plants using combustion technologies are about 14 – 28%. In order to avoid losing the rest of the energy, it can be used for e.g. district heating (cogeneration). The total efficiencies of cogeneration incinerators are typically higher than 80% (based on the lower heating value of the waste).

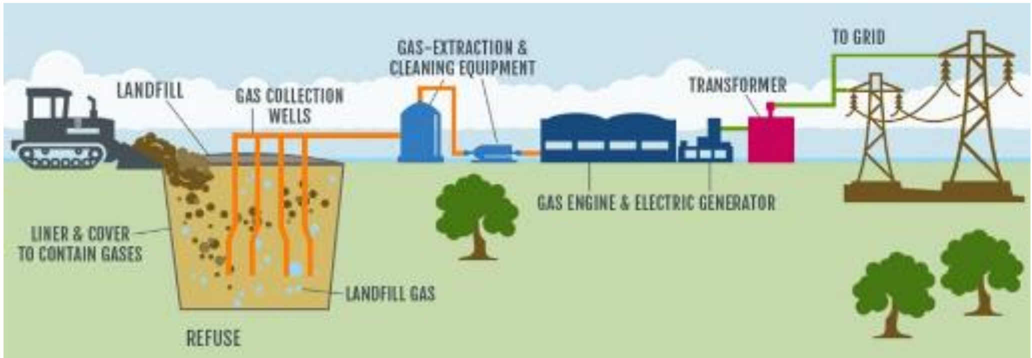
Landfill gas (LFG) power plants

The disposal of waste by land filling or land spreading is the current most common fate of solid waste. As solid waste in landfills decomposes, landfill gas (LFG) is released. Landfill gas consists of approximately 50 – 55% methane, 45 – 50% carbon dioxide, 2 – 5% nitrogen and about 1% oxygen compounds. Landfill gas is a readily available, local and renewable energy source that offsets the need for non-renewable resources such as oil, coal and gas.



LFG generation and changes over time (Source: MEMR (2020), Waste to Energy Guidebook).

Using gas engines, landfill gas can be used as fuel feedstock to produce electricity. The production volume of landfill gas from the same sites can have a range of 2-16 m^3/day.



Landfill gas to energy (ref. 5)

Based on a Ministry of Energy and Mineral Resources statistic, total landfill gas (LGF) power plant potential in Indonesia is 535 MW, due to the fact that the majority of the landfills are open dumping systems (see table below). If the systems are properly designed, then the potential of LFG could be higher.

Province	Capacity Potential (MWe)
Aceh	0.94
North Sumatera	31.35
West Sumatera	7.14
Riau	7.69
Riau Islands	17.21
Jambi	1.63
Bengkulu	0.37
South Sumatera	12.24
Lampung	5.09
West Kalimantan	4.97
Central Kalimantan	1.83
South Kalimantan	3.48
East Kalimantan	8.84
Banten	13.09
West Jawa (including Jakarta)	227.59
Central Jawa	50.32
Yogyakarta	13.1
East Jawa	77.89
Bali	23.65
West Nusa Tenggara	8.87
East Nusa Tenggara	0.9

North Sulawesi	3.99
Gorontalo	1.01
South Sulawesi	11.9
West Papua	0.63
Total	**534.78**

There are currently two landfill gas power plants in operation in Indonesia, one at Bantar Gebang, near Jakarta, with installed capacity of 14.4 MW, the other one at Benowo, Surabaya, with installed capacity of 1.65 MW. Both locations are using sanitary landfill technologies and gas engines to produce electricity *(ref. 13).*

Refuse-Derived Fuels

Refuse-Derived Fuel (RDF) is a fuel or 'feedstock' created as the result of processing and/or treatment of MSW to produce a fuel/feedstock that has a consistent quality. Typically, waste is sorted to focus on the combustible (high net caloric value) portions of MSW (plastics, biodegradable waste etc.), which is then dried and shredded to increase the net caloric value (NCV). RDF can be utilised in any of the thermal treatment plants summarised above, so it is not in itself a unique WtE methodology, rather a method of waste preparation, which aims to optimise WtE recovery. The production of RDF requires that the waste is dried, then either shredded to produce a 'fluff' or pelletized.

RDF fluff (left) and RDF pellets (right) (Source: MEMR (2020), Waste to Energy Guidebook)

RDF production plants tend to be constructed near a high-volume source of MSW and can be linked to a local/adjacent WtE plant. Alternatively, the fuel may be transported for sale to local/regional or even international combustion plants, including WtE plants, cement kilns and coal-fired power stations.

The processing of MSW to produce RDF provides a consistent quality of product that helps to ensure that combustion plants operate with a defined product and more predictable NCV properties. However, all the sorting/processing of waste comes at a cost. Some studies have suggested that RDF combustion has no net economic benefits over mass-burn options, as the cost of producing the RDF outweighs the benefits of combusting a more consistent/reliable MSW product. Markets for RDF in Indonesia are typically focused on the cement industry with Holcim Indonesia or PT Solusi Bangun Indonesia now being one potential consumer, which has shown an interest in RDF.

The table below summarizes the suitability of each technology to selected waste streams from Municipal, Agricultural and Industrial sources. The basic outputs of each technology are also given in terms of electricity, heat, biogas, digestate, syngas and other commercial solids.

	CONVERSION TECHNOLOGIES	Anaerobic digestion	Landfill gas recovery	Incineration	Gasification	Pyrolysis
WASTE STREAMS						
Municipal or industrial	Food waste	🟢	🟢	🟡	🟡	🟡
	Garden and park waste	🟢	🟢	🟡	🔴	🔴
	Dry recoverable waste	🔴	🔴	🟢	🟢	🟢
	Refuse Derived Fuel	🔴	🔴	🟢	🟢	🟢
	Inert	🔴	🟢	🔴	🔴	🔴
	Hazardous	🔴	🔴	🟡	🔴	🔴
	Solid Recovered Fuel	🔴	🔴	🟢	🟢	🟢
Agricultural	Biomass	🟢	🟢	🟡	🟡	🟡
	Animal waste	🟢	🟢	🟡	🟡	🟡
	Dry recoverable waste	🔴	🔴	🟢	🟢	🟢
	Hazardous	🔴	🔴	🟡	🔴	🔴
OUTPUTS						
	Electricity	x	x	x	x	x
	Heat	x	x	x	x	x
	Biogas	x	x			
	Digestate	x				
	Syngas				x	x
	Other commercial solids			x	x	x

Key: 🟢 Directly suitable 🟡 Likely to require pre-treatment 🔴 Unsuitable

Summary of waste to energy technologies' suitability per waste stream and potential output (ref. 4)

Input

MSW and other combustible wastes, water and chemicals for flue gas treatment, gasoil or natural gas for auxiliary burners (if installed), and in some cases biomass for starting and closing down.

Landfill gas is the fuel feedstock for the landfill gas power plants. Internal combustion engines have generally been used at landfills where gas quantity is capable of producing 500 kW to 10 MW, or where sustainable LFG flow rates to the engines are approximately 0.2 to 1.6 million CFD at 50% methane. Multiple engines can be combined for projects larger than 1 MW. The following table provides examples of commonly available sizes of internal combustion engines.

Landfill gas flow rates and power output figures for internal combustion engines

Output (kW)	Gas Flow (m^3/hr @ 50% Methane)
325 kW	195
540 kW	324
633 kW	380
800 kW	480
1.2 MW	720

Source: MEMR (2020), Waste to Energy Guidebook

Required feedstock for a number of different capacities and WtE technologies

Type	Capacity (MW)	Required Feedstock (ton/day)
Incinerator (direct combustion)	50	1645.82
	35	1152.07
	20	658.33
Gasification (indirect combustion)	50	1278.14
	35	894.70
	20	511.25
Pyrolisis (indirect combustion)	50	3501.74
	35	2451.22
	20	1400.70

Note: For indirect combustion process it is assumed that the process requires 53% more feedstocks compared to direct combustion (Chen et al., 2015; Münster & Lund, 2010).

Output

For combustion systems, the outputs are electricity and if demand for it the heat as hot (> 110 ºC) or warm (< 110 ºC) water, bottom ash (slag), residues from flue gas treatment, including fly ash. If the flue gas is treated by wet methods, there may also be an output of treated or untreated process wastewater (the untreated wastewater originates from the SO2-step, when gypsum is not produced).

For landfill gas systems, the outputs are electricity and heat. The landfill gas which has been cleaned (from sulphur and carbon dioxide contents) can be sold as commercial gas through natural gas pipeline networks.

Typical capacities

Medium: 10 – 50 MW.
Small: 1 – 10 MW.

Ramping configurations

The plants that using combustion technologies can be down regulated to about 50% of the nominal capacity, under which limit the boiler may not be capable of providing adequate steam quality and environmental performance. For emission control reasons and due to high initial investments, they should be operated as base load.

Landfill gas to energy plants can also be ramped up or down depending on the availability of the landfill gas in a storage.

Advantages/disadvantages

Advantages:

- Waste volumes are reduced by an estimated 80-95%.
- Reduction of other electricity generation.
- Reduction of waste going to landfills.
- Avoidance of disposal costs and landfill taxes.
- Use of by-products as fertilizers.
- Avoid or utilisation of methane emissions from landfills.
- Reduction in carbon emitted.
- Domestic production of energy.
- The ash produced can be used by the construction industry.
- Incineration also eliminates the problem of leachate that is produced by landfills.

Disadvantages:

- Incineration facilities are expensive to build, operate, and maintain. Therefore, incineration plants are usually built for environmental benefits, instead of power generation reasons.
- Smoke and ash emitted by the chimneys of incinerators include acid gases, nitrogen oxide, heavy metals, particulates, and dioxin, which is a carcinogen. Even with controls in place, some remaining dioxin still enters the atmosphere.
- Incineration ultimately encourages more waste production because incinerators require large volumes of waste to keep the fires burning, and local authorities may opt for incineration over recycling and waste reduction programs.

It has been estimated that recycling conserves 3-5 times more energy than waste-to-energy generates because the energy required to make products derived from recycled materials is significantly less than the energy used to produce them from virgin raw materials.

In developing countries like Indonesia, waste incineration is likely not as practical as in developed countries, since a high proportion of waste in developing countries is composed of kitchen scraps. Such organic waste is composed of higher moisture content (40-70%) than waste in industrialized countries (20-40%), making it more difficult to burn.

Environment

Municipal solid waste (MSW) incinerators require effective flue gas treatment (FGT) to meet stringent environmental regulations. However, this in turn generates additional environmental costs through the impacts of materials and energy used in the treatment. A total of eight technologies: electrostatic precipitators and fabric filters for removal of particulate matter; dry, semi-dry and wet scrubbers for acid gases; selective non-catalytic and catalytic reduction of nitrogen oxides (NOx); and activated carbon for removal of dioxins and heavy metals, are now commercially available in the market (ref. 14).

The incineration process produces two types of ash. Bottom ash comes from the furnace and is mixed with slag, while fly ash comes from the stack and contains components that are more hazardous. In municipal waste incinerators, bottom ash is approximately 10% by volume and approximately 20 to 35% by weight of the solid waste input. Fly ash quantities are much lower, generally only a few percent of the input. Emissions from incinerators can include heavy metals, dioxins and furans, which may be present in the waste gases, water or ash. Plastic and metals are the major source of the calorific value of the waste. The combustion of plastics, like polyvinyl chloride (PVC), gives rise to these highly toxic pollutants.

Leachate generation is a major problem for municipal solid waste (MSW) landfills and causes significant threats to surface water and groundwater. Leachate may also contain heavy metals and high ammonia concentration that might be inhibitory to the biological processes. Technologies for landfill leachate treatment include biological treatment, physical/chemical treatment and “emerging” technologies such as reverse osmosis (RO) and evaporation.

Leachate collection and treatment pond at Bantar Gebang Landfill gas power plant. (ref. 8)

Research and development

Waste incineration plants is a very mature technology (category 4), whereas landfill gas is commercialised, but still being gradually improved (category 3). There are, however, a number of other new and emerging technologies that are able to produce energy from waste and other fuels without direct combustion. Many of these technologies have the potential to produce more electric power from the same amount of fuel than would be possible by direct combustion. This is mainly due to the separation of corrosive components (ash) from the converted fuel, thereby allowing higher combustion temperatures in e.g. boilers, gas turbines, internal combustion engines, fuel cells. Some are able to efficiently convert the energy into liquid or gaseous fuels:

- *Pyrolysis* — MSW is heated in the absence of oxygen at temperatures ranging from 290 to 704 degrees Celsius. This releases a gaseous mixture called syngas and a liquid output, both of which can be used for electricity, heat, or fuel production. The process also creates a relatively small amount of charcoal. (ref. 1)
- *Gasification* — MSW is heated in a chamber with a small amount of oxygen present at temperatures ranging from 400 to 1650 degrees Celsius. This creates syngas, which can be burned for heat or power generation, upgraded for use in a gas turbine, or used as a chemical feedstock suitable for conversion into renewable fuels or other bio-based products. (ref. 1)
- *Plasma Arc Gasification* — Superheated plasma technology is used to gasify MSW at temperatures of 5500 degrees Celsius or higher - an environment comparable to the surface of the sun. The resulting process incinerates nearly all of the solid waste while producing from two to ten times the energy of conventional combustion (ref. 1).

Efficiency of Energy Conversion Technologies (ref. 9 and ref. 10)

Technology	Efficiency (kWh/ton of waste)
Landfill gas	41 – 84
Combustion (incinerator)	470 – 930
Pyrolysis	450 – 530
Gasification	400 – 650
Plasma arc gasification	400 – 1250

Expected Landfill Diversion (ref. 11 and ref. 12)

Technology	**Land diversion (% weight)**
Landfill gas	0
Combustion (incinerator)	75*
Pyrolysis	72 – 95
Gasification	94 – 100
Plasma arc gasification	95 – 100

* 90% by volume

Examples of current projects

Based on the Presidential Ordinance No. 35/2018 on the Acceleration of Waste-to-Energy (WtE) Projects, the government of Indonesia has selected 12 big cities to develop WtE projects immediately, including Jakarta, Tangerang, Tangerang Selatan, Bekasi, Bandung, Semarang, Surakarta, Surabaya, Makassar, Denpasar, Palembang and Manado municipalities. Except Surakarta and Surabaya, all projects use combustion technology or incineration. Surakarta and Surabaya WtE plants apply gasification technology. The WtE plant in Surabaya will be commercially in operation this year. Other WtE plants are still in process to be built. Total installed capacity would be 234 MW. By the end of 2022, all WtE projects should have been already finished (see list below).

Waste to Energy Projects in Indonesia

WtE Project	Location	Commercial Operation Date (COD)	Capacity (MW)
PLTSa Surabaya	East Jawa	2020	10
PLTSa Bekasi	West Jawa	2021/2022	10
PLTSa Surakarta	Central Jawa	2021/2022	10
PLTSa Jakarta	Jakarta	2021/2022	35
PLTSa Bandung	West Jawa	2021/2022	29
PLTSa Denpasar	Bali	2021/2022	20
PLTSa Palembang	South Sumatera	2021/2022	20
PLTSa Makasar	South Sulawesi	2021/2022	20
PLTSa Tangerang Selatan	Banten	2021/2022	20
PLTSa Menado	North Sulawesi	2021/2022	20
PLTSa Tangerang	Banten	2021/2022	20
PLTSa Semarang	Central Jawa	2021/2022	20
Total			234

Source: Coordinating Ministry for Economic Affairs, 2019

Waste to Energy project in Jakarta will consist of four plants which are located at areas of Sunter (North Jakarta), Marunda (North Jakarta), Cakung (East Jakarta) and Durin Kosambi (West Jakarta). Sunter WtE plant flue gas treatment system will be designed according to EU Limits, presented below.

Emission limits in the EU countries

Component (mg/Nm3)	Limit
Total particulate	10
Sulphur dioxide (SO_2)	50
Nitrogen (NO and NO_2)	200
Hydrogen Chloride (HCl)	10
Mercury (Hg)	0.05
Carbon Monoxide (CO)	50
Hydrogen Fluoride (HFl)	1
Dioxins and Furans	0.1

Source: Fortum of Finland, 2017.

The same Presidential Ordinance also mentions that the central government will give tipping fee subsidy at the maximum amount of Rp 500 000 per ton MSW to every provincial government. The Minister of Environment and Forestry will submit a proposal to the Minister of Finance regarding the exact amount of tipping fee subsidy. The regulation also determines the formula for electricity tariff for Waste to Energy projects. Based on the formula, the electricity tariff for capacities less than or equal to 20 MW will be US$ 13.35 cent/kWh. For capacities above 20 MW the electricity tariff will be based on the formula of 14.54 – [0.076 x capacity] cent/kWh.

In 2020, Indonesia officially inaugurated the first RDF plant in Cilacap, Central Jawa with input capacity of 120 tons of MSW per day. This RDF plant applies biodrying technology to process the waste. The resulted products are RDF fluff.

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Data sheets

The following pages contain the data sheets of the technology. All costs are stated in U.S. dollars (USD), price year 2022. The uncertainty is related to the specific parameters and cannot be read vertically – meaning a product with lower efficiency do not have the lower price or vice versa.

Technology

Technology	Incineration Power Plant - Municipal Solid Waste								
	2023	2030	2050	Uncertainty (2023)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	22	22	23						
Generating capacity for total power plant (MWe)	22	22	23						
Electricity efficiency, net (%), name plate	29	30	31	28	32	30	33	A	1
Electricity efficiency, net (%), annual average	28	29	29	27	30	28	31		1
Forced outage (%)	1	1	1						1
Planned outage (weeks per year)	2.9	2.6	2.1						1
Technical lifetime (years)	25	25	25						1
Construction time (years)	2.5	2.5	2.5						1
Space requirement (1000 m^2/MWe)	1.5	1.5	1.5						1
Additional data for non thermal plants									
Capacity factor (%), theoretical	-	-	-	-	-	-	-		
Capacity factor (%), incl. outages	-	-	-	-	-	-	-		
Ramping configurations									
Ramping (% per minute)	10.0	10.0	10.0	7.5	12.5	7.5	12.5	C	1
Minimum load (% of full load)	20.0	20.0	20.0	15.0	25.0	15.0	25.0	C	1
Warm start-up time (hours)	0.50	0.50	0.50	0.38	0.63	0.38	0.63	C	1
Cold start-up time (hours)	2.0	2.0	2.0	1.5	2.5	1.5	2.5	C	1
Environment									
PM 2.5 (mg per Nm^3)									
SO_2 (degree of desulphuring, %)									
NO_X (g per GJ fuel)									
CH_4 (g per GJ fuel)									
N_2O (g per GJ fuel)									
Financial data									
Nominal investment (million $/MWe)	5.97	5.52	4.94	4.48	6.18	3.71	6.18	C	1,2
- of which equipment	59%	54%	50%	44%	74%	38%	63%		1
- of which installation	41%	46%	50%	31%	51%	38%	63%		1
Fixed O&M ($/MWe/year)	277,818	238,288	205,110	222,300	347,300	164,100	256,400	C	1
Variable O&M ($/MWh)	27.50	24.80	23.90	20.63	34.38	17.93	29.88	C	1
Start-up costs ($/MWe/start-up)									
Technology specific data									
Waste treatment capacity (tonnes/h)	27.70	27.70	27.70					B	

References:

1 Danish Technology Catalogue "Technology Data for Energy Plants, Danish Energy Agency 2022
2 MEMR Focus Group Discussions with various stakeholders for the purposes of updating the Technology Catalogue in 2023

Notes:

A Based on experience from the Netherlands where 30 % electric efficiency is achieve. 1 %-point efficiency subtracted to take into account higher temperature of cooling water in Indonesia (approx. +20 C).

B A waste treatment capacity of 27,7 tonnes/h is assumed and an energy content of 10,4 GJ/ton. The specific financial data is adjusted to reflect that the plant in Indonesia runs in condensing mode and hence the electric capacity (MWe) is higher than that of a combined heat and power, backpressure plant with the same treatment capacity.

C Uncertainty (Upper/Lower) is estimated as +/- 25%.

D Calculated from size, fuel efficiency and an average calory value for waste of 9.7 GJ/ton.

Technology

Technology	Landfill Gas Power Plant - Municipal Solid Waste								
	2023	2030	2050	Uncertainty (2023)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	1	1	1	1	10	1	10		1
Generating capacity for total power plant (MWe)	1	1	1	1	10	1	10		1
Electricity efficiency, net (%), name plate	35	35	35	25	37	25	37		2
Electricity efficiency, net (%), annual average	34	34	34	25	37	25	37		2
Forced outage (%)	5	5	5	2	15	2	15		4
Planned outage (weeks per year)	5	5	5	2	15	2	15		4
Technical lifetime (years)	25	25	25	20	30	20	30		3
Construction time (years)	1.5	1.5	1.5	1	3	1	3.0		3
Space requirement (1000 m^2/MWe)									
Additional data for non thermal plants									
Capacity factor (%), theoretical	-	-	-	-	-	-	-		
Capacity factor (%), incl. outages	-	-	-	-	-	-	-		
Ramping configurations									
Ramping (% per minute)									
Minimum load (% of full load)									
Warm start-up time (hours)									
Cold start-up time (hours)									
Environment									
PM 2.5 (mg per Nm^3)									
SO_2 (degree of desulphuring, %)									
NO_X (g per GJ fuel)									
CH_4 (g per GJ fuel)									
N_2O (g per GJ fuel)									
Financial data									
Nominal investment (M$/MWe)	2.90	2.90	2.90	2.64	3.19	2.64	3.34	A	3
- of which equipment	60%	60%	60%	55%	66%	55%	69%		5
- of which installation	40%	40%	40%	36%	44%	36%	46%		5
Fixed O&M ($/MWe/year)	142,500	142,500	142,500	129,550	156,750	129,545	163,875	A	3
Variable O&M ($/MWh)	15.40	15.40	15.40	13.86	16.94	13.09	17.71		
Start-up costs ($/MWe/start-up)									

References:
1 OJK, 2014, "Clean Energy Handbook for Financial Service Institutions", Indonesia Financial Service Authority, Jakarta, Indonesia
2 Renewables Academy" (RENAC) AG, 2014, "Biogas Technology and Biomass", Berlin, Germany.
3 IEA-ETSAP and IRENA, 2015. "Biomass for Heat and Power, Technology Brief".
4 MEMR Focus Group Discussions with various stakeholders for the purposes of updating the Technology Catalogue in 2023
5 MEMR, 2015, "Waste to Energy Guidebook", Jakarta, Indonesia.

Notes:
A Uncertainty (Upper/Lower) is estimated as +/- 10-15%.

17. Biogas Power Plant

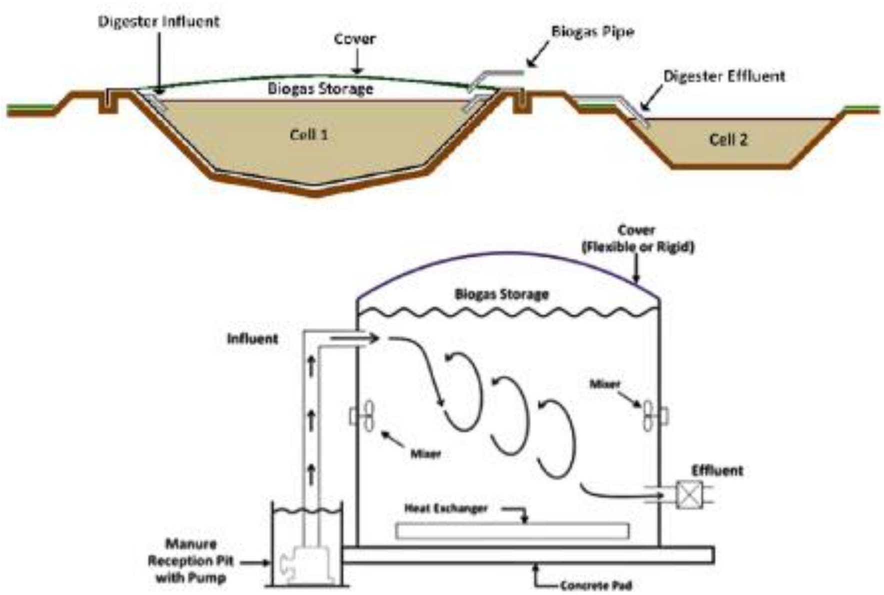
Brief technology description

Biogas produced by anaerobic digestion is a mixture of several gases. The most important part of the biogas is methane. Biogas has a caloric value between 23.3 – 35.9 MJ/m3, depending on the methane content. The percentage of volume of methane in biogas varies between 50% to 72% depending on the type of substrate and its digestible substances, such as carbohydrates, fats and proteins. If the material consists of mainly carbohydrates, the methane production is low. However, if the fat content is high, the methane production is likewise high. For the operation of power generation or CHP units with biogas, a minimum concentration of methane of 40% to 45% is needed. The second main component of biogas is carbon dioxide. Its composition in biogas reaches between 25% and 50% of volume. Other gases present in biogas are hydrogen sulphide, nitrogen, hydrogen and steam (ref. 1, 2).

Feedstocks biogas production in Indonesia are mainly from animal manure, agricultural waste including agriculture industries like palm oil mill effluent (POME), municipal solid waste (MSW) and landfill. Some of the biomass potential can be converted to biogas. MSW and landfill biogas will be discussed in chapter 7. It is estimated that the biogas potential from POME in Indonesia is about 430 MWe in 2015 (ref. 3).

Anaerobic digestion (AD) is a complex microbiological process in the absence of oxygen used to convert the organic matter of a substrate into biogas. The population of bacteria which is able to produce methane cannot survive with the presence of oxygen. The microbiological process of AD is very sensitive to changes in environmental conditions, like temperature, acidity, level of nutrients, etc. The temperature range that would give better cost-efficiency for operation of biogas power plants are around 35 – 38ºC (mesophilic) or 55 – 58ºC (thermophilic). Mesophilic gives hydraulic retention time (HRT) between 25 – 35 days and thermophilic 15 – 25 days (ref. 2).

There are different types and sizes of biogas systems: household biogas digesters, covered lagoon biogas systems and Continuously Stirred Tank Reactors (CSTR) or industrial biogas plants. The last two systems have been largely applied to produce heat and/or electricity (CHP) commercially for own use and sale to customers.



Covered lagoon and CSTR biogas plants (ref.3)

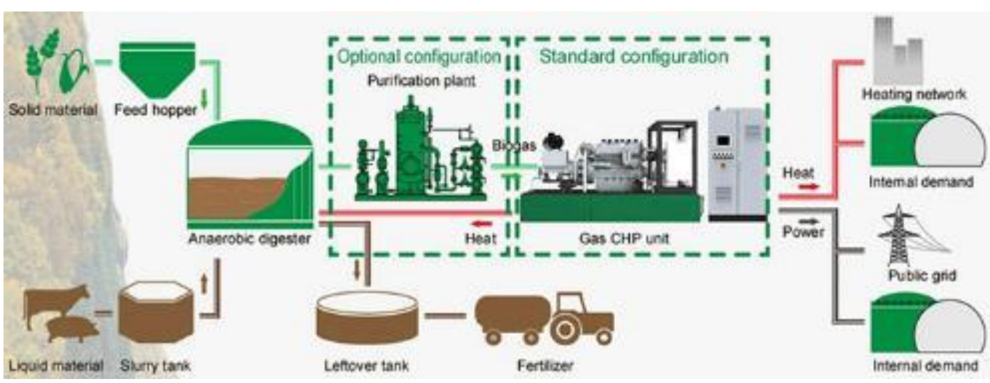
Covered lagoon systems are applied when biogas feedstocks are mostly liquid waste like POME. POME is stored in a lake that is covered by an airtight membrane to capture biogas during anaerobic biological conversion processes. In CSTR systems, liquid waste is stored in tanks to capture biogas during the anaerobic biological conversion process. In general, this type of technology has several stirrers in the tank that serves to stir the material that has higher solids content (≥12%) continuously.

The output of biogas depends much on the amount and quality of supplied organic waste. For manure the gas output is typically 14 – 14.5 m3 methane per tonne, while the gas output typically is 30 – 130 m3 methane per tonne for industrial waste (ref. 4). Additional biogas storage is required when the consumption of biogas is not continuous. Biogas storage would be beneficial to accommodate when demand is higher or lower than the biogas production.

The potential electricity that can be generated from Palm Oil Mill Effluent (POME) (from EBTKE)

Parameters	Value	Unit
Fresh Fruit Bunch (FFB)	1,000,000	ton/year
POME yield	650,000	m3
Biogas yield from POME	25	m3-biogas/m3-POME
Methane (CH4) fraction in biogas	0.625	m3-methane/m3-biogas
Methane emitted	10,156,250	m3
Electricity production (38% efficiency)	38.6	GWh
Capacity (100% availability)	4.4	MW

Biogas from a biodigester is transported to the gas cleaning system to remove sulphur and moisture before entering the gas engine to produce electricity. The excess heat from power generation with internal combustion engines can be used for space heating, water heating, process steam covering industrial steam loads, product drying, or nearly any other thermal energy need. The efficiency of a biogas power plant is about 35% if it is just used for electricity production. The efficiency can increase to 80% if the plant is operated as combined heat and power (CHP).



Biogas CHP working diagram (ref. 5)

Input

Bio-degradable organic waste without environmentally harmful components such as, animal manure, solid and liquid organic waste from industry. Sludge from sewage treatment plants and the organic fraction of household waste may also be used.

Output
Electricity and heat.
The data presented in this technology sheet assumes that the biogas is used as fuel in an engine, which produces electricity and heat, or sold to a third party. However, the gas may also be injected into the natural gas grid or used as fuel for vehicles. The digested biomass can be used as fertilizer in crop production.

Typical capacities
Medium: 10 – 50 MW.
Small: 1 – 10 MW.

Ramping configurations
Similar to gas power plants, biogas power plants can ramp up and down. However, there is a biological limit to how fast the production of biogas can change. This is not the case for the plants which have biogas storage. Biogas storage would be beneficial to accommodate when demand is higher or lower than the biogas production.

Advantages/disadvantages
The CO_2 abatement cost is quite low, since methane emission is mitigated.

- Saved expenses in manure handling and storage; provided separation is included and externalities are monetized.
- Environmentally critical nutrients, primarily nitrogen and phosphorus, can be redistributed from overloaded farmlands to other areas.
- The fertilizer value of the digested biomass is better than the raw materials. The fertilizer value is also more well known, and it is therefore easier to distribute the right amount on the farmlands.
- Compared with other forms of waste handling, biogas digestion of solid biomass has the advantage of recycling nutrients to the farmland in an economically and environmentally sound way.

Environment
Biogas is a CO_2-neutral fuel. Also, without biogas fermentation, significant amounts of the greenhouse gas methane will be emitted to the atmosphere. For biogas plants in Denmark the CO_2 mitigation cost has been determined to approx. 5 € per tonne CO_2-equivalent (ref. 6).

The anaerobically-treated organic waste product is almost free compared to raw organic waste, however, methane slips are possible during the anaerobic digestion.

Research and development
Stirling engines create opportunities to produce electricity (and also heat) using biogas of any type and quality (category 3). A Stirling engine is a heat engine that operates by cyclic compression and expansion of air or other gases (the working fluid) at different temperatures, such that there is a net conversion of heat energy to mechanical work (ref. 7). More specifically, the Stirling engine is a closed-cycle regenerative heat engine with a permanently gaseous working fluid.

Stirling engines have a high efficiency compared to steam engines, being able to reach 50% efficiency. They are also capable of quiet operation and can use almost any heat source. The heat energy source is generated externally to the Stirling engine rather than by internal combustion as with Otto cycle or Diesel cycle engines. Because the Stirling engine is compatible with alternative and renewable energy sources it could become increasingly significant as the price of conventional fuels rises, and also in light of concerns such as depletion of oil supplies and climate change.

The current Stirling combined heat and power system (ref. 8) can produce both electricity and heat from a methane gas concentration as low as 18% – with multiple applications from biogas and landfill sites to wastewater treatment.

Makel Engineering, Inc. (MEI), Sacramento Municipal Utility District, and the University of California, Berkeley developed a homogenous charge compression ignition (HCCI) engine-generator (genset) that efficiently produces electricity from biogas. The design of the HCCI engine-generator set, is based on a combination of spark ignition and compression ignition engine concepts, which enables the use of fuels with very low energy content (such as biogas from digesters) to achieve high thermal efficiency while producing low emissions. Field demonstrations at a dairy south of Sacramento, California show that this low-cost, low-emission energy conversion system can produce up to 100 kW of electricity while maintaining emission levels that meet the California Air Resources Board's (ARB) strict regulations (ref. 9).

Investment cost estimation

As for biomass plants, the investment cost data for biogas plants highly depend on the feedstock that is gasified. This determines the calorific value of the gas, the number of impurities (and the need for equipment to remove them), and any special treatment the feedstock needs to receive before the gasification. Hence, in this catalog, the investment cost figures are based on recent PPAs/tariffs in Indonesia.

Investment costs [$MUSD_{2022}$/MW]		**2020**	**2023**	**2030**	**2050**
Catalogues	**New Catalogue (2023)**		**2.45**	**2.08**	**1.84**
	Existing Catalogue (2020)	2.45		2.07	1.82
Indonesia data	PPA data[1]	2.31			
	Feed-in Tariff, own calculation[2]	1.79	1.79 - 2.45[*]	2.45	
	ESDM[3]		2.45		
International data	Danish technology catalogue		1.21	1.09	1.02
	NREL ATB		4.30	4.14	3.70
	IEA Bioenergy (Task 32)		2.90	2.80	2.80
Projection	Development curve – cost trend [%]		100%	85%	75%

[1]*PPA results signed in 2018 with COD 2018-2019 as summarized in the presentation by Ignasius Jonan in "Renewable Energy for Sustainable Development" (Bali, 12 Sept 2018).*

[2]*FIT levels proposed by ESDM in the draft PERPRES Harga Listrik EBT. Back calculation of CAPEX based on a WACC of 12%.*

[3]*ESDM presentation on "KATADATA Shifting Paradigm: Transition towards sustainable energy". Sampe L. Purba (26 August 2020)*

[*]*Considering fuel cost in the range 2-3 USD/GJ*

Examples of current projects

Small Scale Biogas Power Plant: Terantam Biogas Power Plant (ref. 12)

The development of biogas power plants in Indonesia is still limited to small capacities, less than 10 MWe. Terantam Biogas Power Plant, a collaboration between PT Perkebunan Nusantara V and the Agency for the Assessment and Application of Technology, at the Terantam Palm Oil Mill owned by PT Perkebunan Nusantara (PTPN) V at Tapung Hulu District, Kampar Regency, Riau was officially in operation in 2019. The construction of the biogas power plant starts in 2017 and needs an investment cost of of 27 billion rupiahs or equals 1.86 million USD. The feedstock used to generate electricity comes from palm oil mill effluent (POME) or liquid waste from the Terantam palm oil mill and is capable of generating electricity up to 0.7 MW. This biogas plant is covered lagoon type. Utilization of methane gas from palm oil liquid waste for electricity production can make the company save around 12.5 billion rupiah from fossil fuel expenditure per year. All electricity produced will be used by the palm oil mill itself.

Teratam Biogas Power Plant (covered lagoon type) at Kampar, Riau (ref. 13)

Another example of biogas power plant that is being under construction is Sei Mangkei Biogas Power Plant. This 2.4 MW Sei Mangkei Biogas Power Plant was developed under cooperation between PT Pertamina Power Indonesia and PT Perkebunan Nusantara III in North Sumatera. The construction started in 2018. The company expect to run the plant commercially this year. The plant uses 2 unit of gas engine manufactured by Siemens Gas Engine Factory Zumaia, Spain. The feedstock is supplied with the POME waste from PT Perkebunan Nusantara III.

The largest biogas power plant in the world is located in Finland. It has an installed capacity of 140 MW. Fueled mainly with wood residue from Finland's large forestry sector, the plant is expected to reduce carbon-dioxide emissions by 230,000 tons per year while providing both heating and electricity for Vaasa's approximately 61,000 residents (ref. 11).

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Data sheets

The follow pages contain the data sheets of the technology. All costs are stated in U.S. dollars (USD), price year 2022. The uncertainty is related to the specific parameters and cannot be read vertically – meaning a product with e.g. lower efficiency does not have a lower price.

Technology

Technology	Biogas power plant								
	2023	2030	2050	Uncertainty (2023)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	1	1	1						3
Generating capacity for total power plant (MWe)	1	1	1						3
Electricity efficiency, net (%), name plate	35	35	35						4
Electricity efficiency, net (%), annual average	34	34	34						4
Forced outage (%)	5	5	5						1
Planned outage (weeks per year)	5	5	5						1
Technical lifetime (years)	25	25	25						7
Construction time (years)	1.5	1.5	1.5						7
Space requirement (1000 m^2/MWe)	70	70	70						12
Additional data for non thermal plants									
Capacity factor (%), theoretical	-	-	-	-	-	-	-		
Capacity factor (%), incl. outages	-	-	-	-	-	-	-		
Ramping configurations									
Ramping (% per minute)	20	20	20	10	30	10	30		11
Minimum load (% of full load)	20	30	15	30	50	10	40		10
Warm start-up time (hours)									
Cold start-up time (hours)									
Environment									
PM 2.5 (mg per Nm^3)									
SO_2 (degree of desulphuring, %)									
NO_X (g per GJ fuel)									
CH_4 (g per GJ fuel)									
N_2O (g per GJ fuel)									
Financial data									
Nominal investment (M$/MWe)	2.45	2.08	1.84	1.67	2.31	1.30	2.20	B	3,5,8,9
- of which equipment	65%	65%	65%	50%	85%	50%	85%		1,2
- of which installation	35%	35%	35%	15%	50%	15%	50%		1,2
Fixed O&M ($/MWe/year)	110,580	101,700	88,500	78,294	130,455	59,043	98,406	A	5,7,9
Variable O&M ($/MWh)	0.13	0.12	0.10	0.10	0.20	0.10	0.10	A	6,9
Start-up costs ($/MWe/start-up)									

References:

1 MEMR Focus Group Discussions with various stakeholders for the purposes of updating the Technology Catalogue in 2023

2 ASEAN Centre of Energy (2016). Levelised cost of electricity generation of selected renewable energy technologies in the ASEAN member states.

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6 OJK, 2014, "Clean Energy Handbook for Financial Service Institutions", Indonesia Financial Service Authority.

7 IEA-ETSAP and IRENA, 2015, "Biomass for Heat and Power, Technology Brief".

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9 Learning curve approach for the development of financial parameters.

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11 Deutsches Institut für Wirtschaftsforschung, On Start-up Costs of Thermal Power Plants in Markets with Increasing Shares of Fluctuating Renewables, 2016.

12 Chazaro Gerbang Internasional, 2004, "Utilization of Biogas Generated from the Anaerobic Treatment of Palm Oil Mills Effluent (POME) as Indigenous Energy Source for Rural Energy Supply and Electrification - A Pre-Feasibility Study Report"

Notes:

A Uncertainty (Upper/Lower) is estimated as +/- 25%.

B For 2020, uncertainty ranges are based on cost spans of various sources. For 2050, we combine the base uncertainity in 2020 with an additional uncertainty span based on learning rates variying between 10-15% and capacity deployment from Stated Policies and Sustainable Development scenarios separately.

18. Diesel Engine

Brief technology description

In a diesel engine, the fuel is pumped from a storage tank and fed into a small day tank which supplies the daily need for the engine. Diesel power plants may use different oil products, including heavy fuel oil (or "residual fuel oil") and crude oil. Heavy fuel oil is cheaper than diesel, but more difficult to handle. It has a high viscosity, almost tar-like mass, and needs fuel conditioning (centrifugal separators and filters) and preheating before being injected into the engine.

The temperatures in the engine are very high (1500-2000°C) and therefore a cooling system is required. Water is circulated inside the engine in water jackets and normally cooled in a cooling tower (or by sea water).

The waste heat from the engine and from the exhaust gasses may also be recovered for space heating or industrial processes.

It is also an option, to use the waste heat from diesel exhaust gasses in combined cycle with steam turbine generator. Typically, this is only considered relevant in large-scale power stations (50 MWe or above) with high capacity factors.

Due to relatively high fuel costs, diesel power plants are mainly used in small or medium sized power systems or as peak supply in larger power systems. In small power systems they can also be used in combination (backup) with renewable energy technologies. Several suppliers offer turnkey hybrid power projects in the range from 10 to 300 MW, combining solar PV, wind power, biomass, waste, gas and/or diesel (ref 1).

In an idealised thermodynamic process, a diesel engine would be able to achieve an efficiency of more than 60%. Under real conditions, plant net efficiencies are 45-46%. For combined cycle power plants efficiencies of 50% are reached (ref. 5).

Input
Diesel engines may use a wide range of fuels including: crude oil, heavy fuel oil, diesel oil, emulsified fuels (emulsions composed of water and a combustible liquid), and biodiesel fuel. Engines can also be converted to operation on natural gas.

Output
Power.

Typical capacities
Up to approx. 300 MWe. Large diesel power plants (>20 MWe) would often consist of multiple engines in the size of 1-23 MWe (ref 5)

Ramping configurations
Combustion engine power plants do not have minimum load limitations and can maintain high efficiency at partial load due to modularity of design – the operation of a subset of the engines at full load. As load is decreased, individual engines within the generating set can be shut down to reduce the output. The engines that remain operating can generate at full load, maintaining high efficiency of the generating set.

Diesel power plants can start and reach full load within 2-15 minutes (under hot start conditions). Synchronization can take place within 30 seconds. This is beneficial for the grid operator, when an imbalance between supply and demand begins to occur.

Engines are able to provide peaking power, reserve power, load following, ancillary services including regulation, spinning and non-spinning reserve, frequency and voltage control, and black-start capability (ref 2,3).

Advantages/disadvantages

Advantages

- Minimal impact of ambient conditions (temperature and altitude) on plant performance and functionality
- Fast start-stop
- High efficiency in part load
- Modular technology – allowing most of the plant to generate during maintenance
- Short construction time, example down to 10 months.
- Proven technology with high reliability

Disadvantages

- Diesel engines cannot be used to produce considerable amounts of high-pressure steam, as approx. 50% of the waste heat is released at lower temperatures.
- Expensive fuel.
- High environmental impact on NOx and SO2.

Environment

Emissions highly depend on the fuels applied, fuel type and its content of sulphur etc.

Emissions may be reduced via fuel quality selection and low emission technologies or by dedicated (flue gas) abatement technologies such as SCR (selective catalytic reduction) systems. Modern large-scale diesel power stations apply lean-burn gas engines, where fuel and air are pre-mixed before entering the cylinders, which reduces NOX emissions.

With SCR technology, NOx levels of 5 ppm, vol, dry at 15% O2 can be attained (ref. 5).

Research and development

Diesel engines are a very well-known and mature technology – i.e. category 4.

Short start-up, fast load response and other grid services are becoming more important as more fluctuating power sources are supplying power grids. Diesel engines have a potential for supplying such services, and R&D efforts are put into this (ref. 6).

Prediction of performance and cost

Diesel power plants is a mature technology and only gradual improvements are expected.

According to the IEA's World Energy Outlook scenario, the global installed capacity of oil-fired plants will decrease in the future and therefore, even when considering replacement of existing oil power plants, the future market for diesel power plants is going to be moderate. Taking a learning curve approach to the future cost development, this also means that the price of diesel power plants can be expected to remain at more or less the same level as today.

Diesel engines may however also run on natural gas and their advantageous ramping abilities compared to gas turbines make them attractive as backup for intermittent renewable energy technologies. This may pave the way for a wider deployment in future electricity markets.

A recent 37 MW project on the Faeroe Island has been announced to cost approx. 200 million Danish kroner corresponding to a price of 0.86 mill. USD/MWe (Ref 7). PLN are planning costs of 0.75 mill. USD/MWe for gas engines (18 MWe per unit).

In the data sheet we consider a 100MWe oil-fired power plant consisting of 5 units, at 20 MWe each and an estimated price of 0.8 mill. USD/MWe.

Examples of current projects

The Arun 184 MW power plant located in the Aceh Special District in northern Sumatra, consist of 19 Wärtsilä 20V34SG engines running on liquefied natural gas (LNG). Operating at peak load/stand-by & emergency, Arun will be able to reach full load in around 10-15 minutes (ref. 4.).

References

The description in this chapter is to a great extend from the Danish Technology Catalogue *"Technology Data on Energy Plants - Generation of Electricity and District Heating, Energy Storage and Energy Carrier Generation and Conversion".* The following sources are used:

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2. Wärtsila, 2017. Combustion Engine vs. Gas Turbine: Part Load Efficiency and Flexibility. Article viewed, 3rd August 2017 https://www.wartsila.com/energy/learning-center/technical-comparisons/combustion-engine-vs-gas-turbine-part-load-efficiency-and-flexibility
3. Wärtsila, 2017. Combustion Engine vs Gas Turbine: Startup Time https://www.wartsila.com/energy/learning-center/technical-comparisons/combustion-engine-vs-gas-turbine-startup-time
4. Wärtsila, 2017.Tackling Indonesia's peaks – the flexible way. Article viewed, 3rd August 2017 https://cdn.wartsila.com/docs/default-source/Power-Plants-documents/reference-documents/reference-sheets/w%C3%A4rtsil%C3%A4-power-plants-reference-arun-indonesia.pdf?sfvrsn=2
5. Wärtsila, 2011. White paper Combustion engine power plants. Niklas Haga, General Manager, Marketing & Business Development Power Plants https://cdn.wartsila.com/docs/default-source/Power-Plants-documents/reference-documents/White-papers/general/combustion-engine-power-plants-2011-lr.pdf?sfvrsn=2
6. Danish Energy Agency, 2016. Technology Data for Energy Plants, August 2016, https://ens.dk/sites/ens.dk/files/Analyser/technology_data_catalogue_for_energy_plants_-_aug_2016._update_june_2017.pdf)
7. BWSC once again to deliver highly efficient power plant in the Faroe Islands. http://www.bwsc.com/News---Press.aspx?ID=530&PID=2281&Action=1&NewsId=206

Data sheets

The following pages contain the data sheets of the technology. All costs are stated in U.S. dollars (USD), price year 2022. The uncertainty is related to the specific parameters and cannot be read vertically – meaning a product with e.g. lower efficiency does not have a lower price.

Technology

Technology	Diesel engine (using fuel oil)								
	2023	2030	2050	Uncertainty (2023)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	3	3	3	0.5	18	0.5	18	E	7
Generating capacity for total power plant (MWe)	14	14	14	1	100	1	100	E	
Electricity efficiency, net (%), name plate	46	47	48						1
Electricity efficiency, net (%), annual average	45	46	47	43	47	45	52		1
Forced outage (%)	3	3	3						
Planned outage (weeks per year)	1	1	1						2
Technical lifetime (years)	25	25	25						2
Construction time (years)	1	1	1						2
Space requirement (1000 m^2/MWe)	0.05	0.05	0.05						2
Additional data for non thermal plants									
Capacity factor (%), theoretical	-	-	-						
Capacity factor (%), incl. outages	-	-	-						
Ramping configurations									
Ramping (% per minute)	25	25	25						
Minimum load (% of full load)	6	6	6					A	1
Warm start-up time (hours)	0.05	0.05	0.05						1
Cold start-up time (hours)	0.3	0.3	0.3						
Environment									
PM 2.5 (gram per Nm^3)	20	20	20					B,C	3,4
SO_2 (g per GJ fuel)	224	224	224					C	3,4
NO_X (g per GJ fuel)	280	280	280					C	3,4
CH_4 (g per GJ fuel)									
N_2O (g per GJ fuel)									
Financial data									
Nominal investment (M$/MWe)	0.91	0.91	0.89	0.80	1.03	0.74	0.97	D	6,7
- of which equipment									
- of which installation									
Fixed O&M ($/MWe/year)	9,120	9,120	8,847						2
Variable O&M ($/MWh)	7.30	6.84	6.61						2
Start-up costs ($/MWe/start-up)	-	-	-						

References:
1 Wärtsila, 2011, "White paper Combustion engine power plants", Niklas Haga, General Manager, Marketing & Business Development Power Plants
2 Danish Energy Agency, 2016, "Technology Data for Energy Plants"
3 Minister of Environment, Regulation 21/2008
4 The International Council on Combustion Engines, 2008: Guide to diesel exhaust emissions control of NOx, SOx, particles, smoke and CO2
5 http://www.bwsc.com/News---Press.aspx?ID=530&PID=2281&Action=1&NewsId=206
6 BWSC once again to deliver highly efficient power plant in the Faroe Islands.
7 PLN, 2023, data provided the System Planning Division at PLN

Notes:
A 30 % minimum load per unit - corresponds to 6% for total plant when consisting of 5 units
B Total particulate matter
C Typical diesel exhaut emission according to Ref 3 (average of interval) unless this number exceeds the maximum allowed emission according to Minister of Environment Regulation 21/2008. Both SO2 and particulates are dependant on the fuel composition.
D Investment cost include the engineering, procurement and construction (EPC) cost. See description under Methodology.
E Based on data collection from Indonesian projects

19. Nuclear Power Generation

Brief technology description

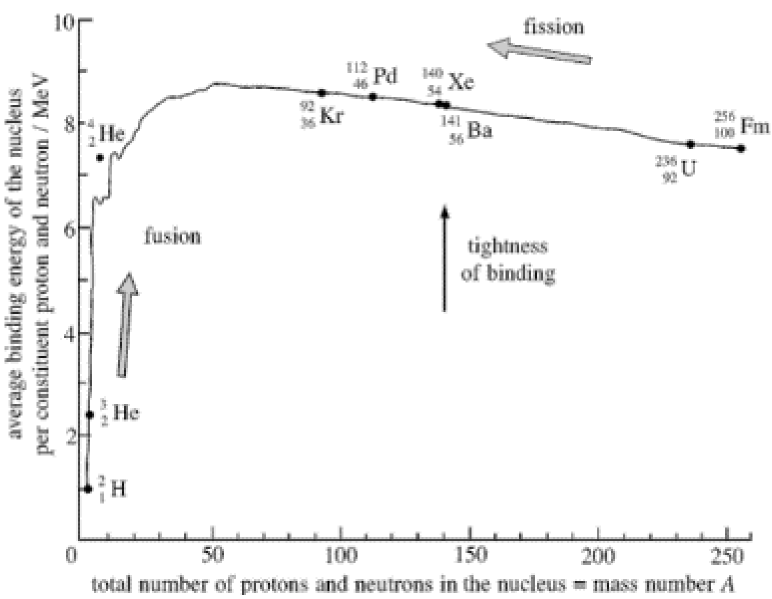
Nuclear energy has been utilised for civil purposes since the mid-1900s. Progress in nuclear engineering has brought about significant changes in the plant layout ever since. Various concepts have been tested and used around the world, building on national and regional research programs. Nuclear power plants are not standardized technology, because geopolitical reasons and historical legacy make nuclear research a national or regional matter.

In broad terms, nuclear energy can be obtained by:

- Splitting the nuclei of specific, heavy chemical elements (nuclear fission)
- Combining the nuclei of light chemical elements (nuclear fusion)

All nuclear power plants operating in the world are of the fission type.

All fission power plants are built on the same concept. Heavy atom nucleus' components (protons, neutrons) are tied together by nuclear forces. Elements with atomic number (Z) over 83 are unstable and decay naturally into elements with a higher binding energy. This occurs because the resulting elements have a higher stability than the original element.



Nuclear energy binding graph (ref. 1)

Fission can also be *induced* by supplying energy to such unstable elements, which in turn release an amount of energy equal to the binding energy of the original element. Induced fission is central for nuclear power plant engineering. The activation energy, which is kinetic energy provided by mobile neutrons hitting the nuclei of selected heavy elements (such as ^{235}U), catalyses a reaction such as the following:

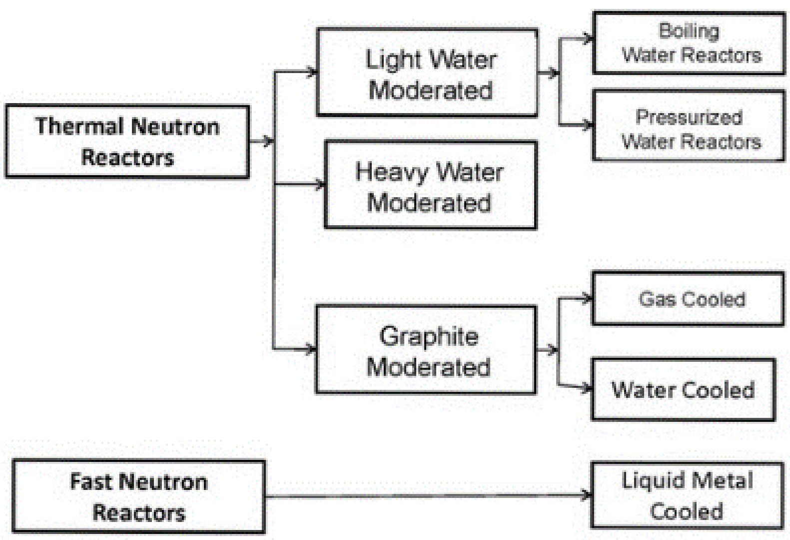
$$ {}_0^1n + {}_{92}^{235}U \rightarrow {}_{56}^{141}Ba + {}_{36}^{92}Kr + 3\,{}_0^1n + energy $$

^{235}U is one of the fissile elements, since it sustains the chain reaction: for every ^{235}U atom splitting, three mobile neutrons *n* are released, which in turn go on hitting other ^{235}U atoms. Energy is released in the form of heat, later used in the power cycle.

Nuclear reactors are designed to sustain and keep a stable reactivity. The central region of a reactor is called the *core.* In a thermal reactor, the core contains the fuel, the moderator, and a coolant. In a fast breeder reactor, there is no moderator, only fuel and coolant. These components are briefly described below:

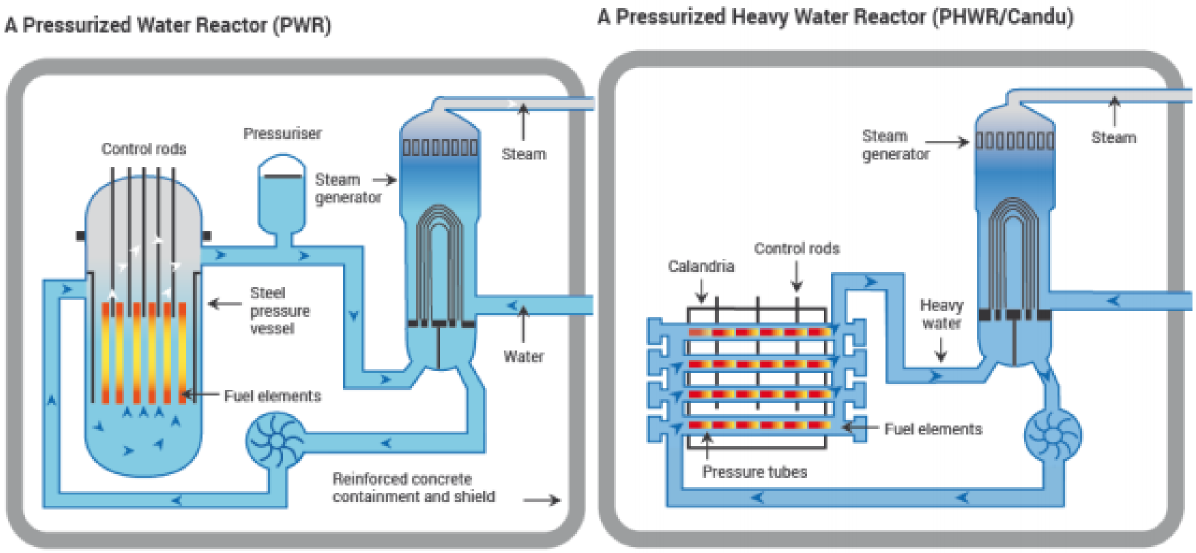
- The fissile material (e.g., ^{235}U). It is contained in rods, which need to be periodically replaced as the core gets short of fissile material (fuel cycle).
- The control elements, typically rods, can be lowered or lifted to regulate reactivity. Rods are made of a certain chemical element which inhibits reactivity by absorbing neutrons, usually high-boron steel and boron carbide.
- The coolant is a fluid circulating through the core, responsible for transferring the heat from it. Water, heavy water and various gases are the most commonly used coolants for thermal reactors. In the case of water and heavy water, these coolants also frequently serve as the moderator. With fast reactors, liquid sodium and gases are most used for coolant.
- The reactor pressure vessel, usually a robust steel vessel containing the reactor core and moderator/coolant. It may also be a series of pressure tubes holding the fuel and conveying the coolant through the surrounding moderator.

Fission power plants are usually classified by the core design, the general classification is as follow:

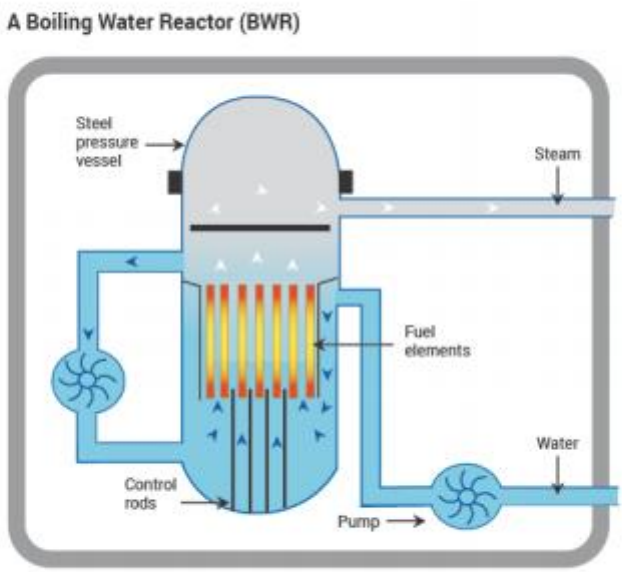


Classification of nuclear reactors

Today the most common reactors are: (i) Pressurized water reactors (PWRs), where the moderator is water kept at high-pressure to prevent vaporization. (ii) Boiling water reactors (BWRs), where the moderator is water turning into steam as it absorbs heat in the core. In both cases, water as a moderator can be either heavy or light, depending on the hydrogen isotope. Today the PWR is the most applied. Nevertheless, other moderators and core designs have been used since the 1950s but have been progressively abandoned.



PWR schemes (ref. 2)



BWR schemes (ref. 2)

In PWRs, the pressurized hot water is turned into steam in a steam generator, which powers a Rankine cycle for electricity production. Unlike BWRs, there exist two circuits (primary and secondary): moderator and working fluid in the power cycle is distinct.

The table below summarizes the reactor designs, which are being operated or are operable.

Reactor type	Main countries	Number	GWe	Fuel	Coolant	Moderator
Pressurized water reactor (PWR)	USA, France, Japan, Russia, China, South Korea	301	286	enriched UO2	water	water
Boiling water reactor (BWR)	USA, Japan, Sweden	64	65	enriched UO2	water	water
Pressurized heavy water reactor (PHWR)	Canada, India	48	24	natural UO2	heavy water	heavy water
Advanced gas-cooled reactor (AGR)	UK	14	8	natural U (metal), enriched UO2	CO2	graphite
Light water graphite reactor (LWGR)	Russia	12	8.4	enriched UO2	water	graphite
Fast neutron reactor (FBR)	Russia	2	1.4	PuO2 and UO2	liquid sodium	none
Total		**441**	**393**			

Examples of nuclear reactor types currently under operation or operable (ref. 2).

Nuclear power plants are also classified based on their performance, cost, and safety. In this classification, nuclear power plants belong to a specific generation:

- *Generation I* reactors (1950s - 1960s): were the first commercial reactors. The design differed from country to country and the reactor could be moderated in different manners (water, gas etc.). No Generation I reactor is still in operation.
- *Generation II* reactors (1970s - 2000s): are essentially water-cooled and moderated. They can be of the PWR/PHWR or BWR type. An exception is the AGR graphite-moderated reactor used in the UK. This generation of reactors are more efficient, reliable and safe than Generation I reactors.
- *Generation III* reactors (2000s - 2010s): Advanced designs (APWR, ABWR, AP600, EPR) feature safety and design improvements with respect to Generation II reactors and are characterized by an extended lifetime (up to 60 years). They are also conceived to have longer fuel cycles, minimizing downtime.
- *Generation III+* reactors (2010s - mid-2020s): Introduction of advanced passive safety features (e.g: in the event of an extreme incident, the reactor is designed with a core-catcher system, radioactive material is kept in the bottom of the furnace tank, not released into the environment), include Russia's VVER-1200/AES 2006; America's AP 1000; French EPR-1750, Advanced CANDU.
- *Generation IV* reactors (mid-2020s onwards). The next generation of nuclear reactors under development by the GIF (Generation IV International Forum), increased efficiency, increased safety and reliability (see further in *Research and development* section).

The power cycle is normally a subcritical Rankine cycle. The efficiency of the cycle depends on the steam characteristics. In some cases, nuclear plants have also been used for heat production. However, given the high costs of nuclear energy, this is not common, as electricity is more valued as a commodity.

Currently, small modular reactors (SMR) are becoming the new trend in nuclear power development. The SMR plants that have been developed until now have adopted one of all principal reactor lines: water cooled reactors, liquid-metal, sodium and gas-cooled reactors with fast neutron spectrum, molten salt reactors, high temperature gas cooled (HTGR) reactors, and recently microreactors (ref. 14).

The status of today is that the majority of SMR projects are in the conceptual design phase, some are under development, and few are in operation. The first operating prototype in the world is the floating SMR power plant Akademic Lomonosov, located in Russia and put into operation from May 2020. It consists of two PWR units of 35 $MW_{(e)}$ (ref. 8), technical and economic information about the Lomonovov plant is, however, limited. Furthermore, one out of two HTGR SMR units has been in operation in China since December 2021. The full capacity of the plants amounts to 210 $MW_{(e)}$. Thus, the capacity of SMR plants in operation today is 175 $MW_{(e)}$. Currently there are around 42 SMR designs in development worldwide (ref. 15), with almost all being in concept design phase.

Small modular reactors (SMRs) are a class of nuclear fission reactors, smaller than conventional nuclear reactors, which can be built in one location (such as a factory), then shipped, commissioned, and operated at a separate site. The term SMR refers to the size, capacity and modular construction only, not to the reactor type and the nuclear process which is applied. Designs range from scaled down versions of existing designs to *Generation IV* designs. Both thermal-neutron reactors and fast-neutron reactors have been proposed, along with molten salt and gas cooled reactor models (ref. 7).

SMRs have a power capacity of up to 300 $MW_{(e)}$ per unit, which is about one-third of the generating capacity of traditional nuclear power reactors. The micro modular reactors are characterized by the smallest capacities and are expected to reach the minimum capacity of 1.5 $MW_{(e)}$. This expectation is based on the capacity for the Aurora power plant, in USA, which still is at the conceptual design phase (ref. 14). Most of the adopted designs of SMR include advanced or inherent safety features and can be delivered as a single or multi-module plant (ref. 14).

- **S**mall Size: They occupy significantly less space compared to conventional nuclear reactors.
- **M**odular Design: This feature allows for components and systems to be pre-assembled in factories and then transported as a complete unit to the installation site.
- **R**eactor Functionality: SMRs employ nuclear fission to produce heat and, subsequently, energy.

The development of SMRs is targeted to achieve some of the characteristics that larger plants are not capable of offering. SMRs could play a role within the flexibility of power generation, and provide cogeneration in areas with small electricity grids, remote and off grid areas. The newer SMRs aim at safety performance that is comparable or improved compared to traditional designs (ref. 14). However, several technical challenges remain to be addressed. New codes and standards are yet to be developed. Multi-module SMR plants brings the challenge of control room staffing and human factor engineering. Moreover, the economic viability of the SMR plants remains to be demonstrated, as most units are slated for future deployment and current projects such as NuScale SMR have become increasingly expensive.

Input
Nuclear fuel, main composition consists of Uranium, Plutonium, Thorium, etc

Output
Electricity.

Typical capacities
Large reactors (conventional reactor) are generally considered reactors with an equivalent electric power higher than 700 MWe.
Medium-sized reactors are defined as "reactors with an equivalent electric power between 300 and 700 MW" (ref. 9).

The International Atomic Energy Agency (IAEA) defines SMRs as "newer generation reactors designed to generate electric power up to 300 MW (ref. 14) and SMR plants' capacity can be as small as few MW, the smallest registered (in conceptual design phase) is 1.5 MW(e) (ref. 14).

Ramping configurations
Modern reactors are able to adjust their operation to follow scheduled or unscheduled load changes. Many modern nuclear power plants (III/III+ generation) can safely operate at 25% of the nominal load and ramp up to full output at a ramping rate of 2.5% per minute up to 60% output and then at a ramping rate of 5% per minute to full rated power. It means that the power plants can change from 25% to 100% nominal rated output in less than 30 minutes (ref. 15). However, nuclear power plants characterized by high investment, high fixed operation and maintenance costs and low variable operation costs, therefore in the feasibility calculations it would typically have be assumed that they will run in base load mode (meaning more than 8000 h/year).

The new SMR have capability to ramp up or down, daily load of SMRs can be performed from 100% to as low as 20% power. If in a setup with multiple SMRs forming a plant, one or more modules could be turned on/off to vary the output of the overall plant.
Small Modular Reactors (SMRs) aim to push the boundaries of this flexibility even further. They can adjust their output daily, operating efficiently anywhere between 100% down to 20% power. In configurations where multiple SMRs are combined to form a larger plant, individual modules can be independently activated or deactivated, offering granular control over the plant's total output.

In Europe, flexibility is a requirement for a nuclear power plant: the plants must be capable of daily cycling between 50% and 100% of their nominal load, maintaining a ramping rate of 3-5% per minute.

Advantages/disadvantages
Advantage and disadvantage of nuclear power compared to other technologies (ref. 1,2,5):

Advantages:
- Well-established technology (conventional reactors)
- Despite past accidents, nuclear power plants are a relatively safe technology.
- High energy density in terms of area required.
- Low carbon emissions. Does not emit greenhouse gases once operational.
- Large fuel storage facility is not required.
- Production level is usually not affected by weather conditions.
- Nuclear power plants are well suited to meet large power demands as they have a high efficiency and load factors (80 to 90%)

Disadvantages:
- Fissile materials (normally uranium) are only available in selected countries on Earth.
- Environmental risks related to mining of fuel.
- Operation patterns conditioned by refueling (fuel cycles).
- Long construction time

- High uncertainty in predicting the construction time (present new ex. of exciting the time schedule by more than 100 %)
- Limited locations suited for power plant construction. Requirements: proximity to load centers, rivers, or the sea to operate the condenser, away from seismic areas.
- Public acceptance issues.
- Geopolitical issues.
- During extreme events, safe operations have not always been guaranteed. Possibility of nuclear disaster.
- High initial capital cost.
- High uncertainty in predicting investment cost (present new examples of exciting the budget by more than 100 %)
- The maintenance cost is high (due to lack of standardization and high salaries of the trained personnel in this field of specialization)
- Handling of nuclear waste and overall safety is a major concern.
- Decommissioning of nuclear power plants is a long and expensive process.

Advantage and Disadvantage of SMR compared to large reactors:

SMR advantages:

- **Enhanced safety and security**: Lower thermal power of the reactor core, compact architecture, and employment of passive concepts have the potential for enhanced safety and security compared to earlier designs and large commercial reactors. The passive safety systems are an important safety feature in the SMR. Therefore, there is less reliance on active safety systems and additional pumps and AC power for accident mitigation. These passive safety systems can dissipate heat even after the loss of offsite power. The safety system incorporates an on-site water inventory that operates on natural forces (e.g., natural circulation, convection, gravity and self-pressurization) (ref. 16, 18). In reactor engineering, natural circulation is a very desired phenomenon since it can provide reactor core cooling without coolant pumps so that no moving parts could break down (ref. 16). These higher safety margins lower or even eliminate the potential for releases of radioactivity to the environment and the public in case of accident (ref. 18).
- **Modularity:** The term 'modular' in SMRs signifies scalability and the ability to fabricate major components of the nuclear steam supply system (NSSS) in a factory setting before transport to the site. This can help limit the on-site preparation and reduce the construction time. This is important since the lengthy construction times are one of the key problems of the larger units.
- **Construction time and financing:** Size, construction efficiency, and passive safety systems (requiring less redundancy) can reduce a nuclear plant owner's capital investment due to the lower plant capital cost. This, in turn, can lead to easier financing compared to larger plants (ref. 16).
- **Reduced refueling needs:** SMRs use only a small amount of fuel and only need to be refueled every 3–7 years, compared to 1–2 years for conventional plants. Some SMRs are even designed to operate for up to 30 years without refueling.

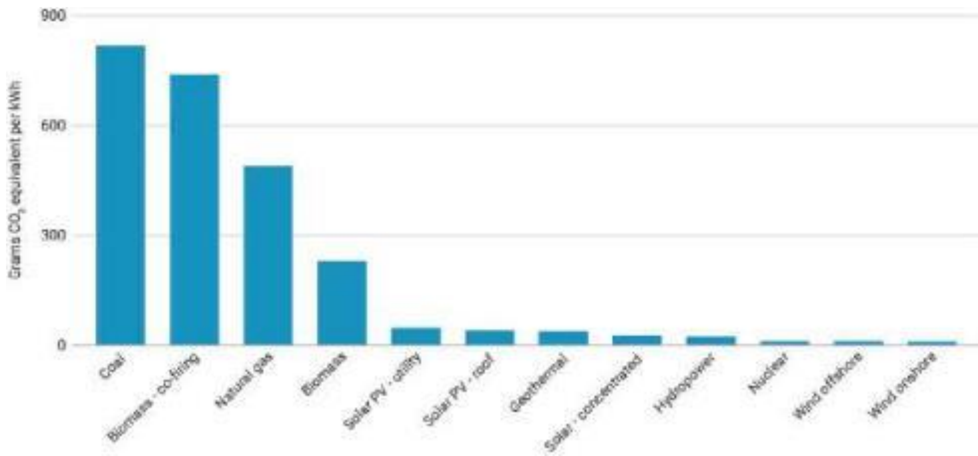
SMR disadvantages:

- **Lack of development**: only a few SMRs are currently in operation for power generation. It is therefore difficult to have confidence in production times, learning rates and cost reductions proposed by the industry (ref. 17).

- **Lost economies of unit scale:** nuclear reactors grew bigger because manufacturers and operators gained commercial advantages from increasing size and output. SMRs lose the advantages of economies of unit-scale and may only be cost-effective in high quantities, which require a large deployment of SMR modules.
- **Licensing:** One of the important barriers is licensing of new reactor designs. The licensing process for a new reactor as SMR designs is lengthy and costly.

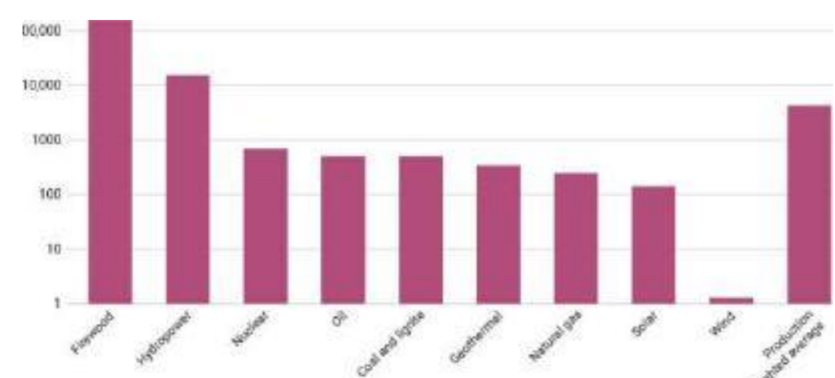
Environment

On a life-cycle basis, nuclear power emits just a few grams of CO_2-equivalent per kWh of electricity produced. A median value of 12 g CO_2 equivalent/kWh has been estimated for nuclear in the IPCC report of 2014 (ref. 20). Such value is relatively low as compared to other combustion-based power generation technologies (ref. 20). These emissions are based on a life cycle approach, assuming 60 years of lifetime and the hours of operation between a minimum of 3700 and 7400 h per year. In operation, a nuclear plant has no CO_2-emissions.



Average life-cycle CO2 equivalent emissions (ref. 2).

In terms of land use, nuclear power plants take up the least space compared to other technologies due to their high energy density (ref. 19). Another environmental aspect relevant to electricity production technologies is the use of water (depicted in the figure below) which is becoming a scarce and valuable resource.



Water consumption per unit of electricity and heat produced (2008-2012) (ref. 2).

Handling radioactive waste is one of the most significant environmental risks. Exposure to certain high levels of radiation, such as that from high level radioactive waste, can even cause death. Radiation exposure can also cause cancer, birth defects, and other abnormalities, depending on the duration of exposure, amount of radiation, and the decay mechanism. High-level radioactive waste from nuclear reactors can be hazardous for thousands of years.

Radioactive waste includes any material that is either intrinsically radioactive, or has been contaminated by radioactivity, and that is deemed to have no further use. Every radioactive particle has a half-life - the time taken for half of its atoms to decay, and thus for it to lose half of its radioactivity. Radioactive particles with long half-lives tend to be easier to handle. Eventually all radioactive waste decays into non-radioactive elements. The more radioactive an isotope is, the faster it decays. The radioactive materials produced by nuclear fission of uranium are divided in short-term, medium-lived, and long-lived fission products. A typical short-term product is the isotope Iodine-131(^{131}I), with a half-life of 8 days, while medium-lived fission product has half-lives of about 30 years. Only seven fission products have half-lives much longer than 30 years, in the range of 200.000 to 16 million years. They are called the long-lived fission products, such as Caesium-135 (^{135}Cs) or Selenium-79 (^{79}Se).

Radioactive waste is produced at all stages of the nuclear fuel cycle. The fuel cycle involves the mining and milling of uranium ore, its processing and fabrication into nuclear fuel, its use in the reactor, its reprocessing, the treatment of the used fuel taken from the reactor, and finally, disposal of the waste. Whilst waste is produced during mining and milling and fuel fabrication, the majority (in terms of radioactivity) comes from the actual 'burning' of uranium to produce electricity. Radioactive waste is typically classified as either low-level (LLW), intermediate-level (ILW), or high-level (HLW), dependent, primarily, on its level of radioactivity.

Currently, many radioactive waste treatment options have been researched and considered, including: burying in the ground, nuclear waste recycling, taken into space, buried under the sea, buried in the subduction zone, buried under the glacier, stored in artificial stone. The two options that are most used today are buried in the ground and recycling.

In waste burial approach, the waste can be temporarily treated/stored on-site (about 40 - 50 years) at the production facility using several methods, such as vitrification, ion exchange or synroc and then will be buried in a dedicated place in long term. In recycling approach, used fuel is processed to separate Plutonium and Uranium for reuse, the rest can be vitrified and buried.

Employment

A study on employment generated by the nuclear power sector, based on plants in OECD countries, suggested that a 1000 $MW_{(e)}$ plant leads to (ref. 3):

- Direct employment during a ten-year period of site preparation and construction of some full-time 1200 professional and construction staff, assuming 2000 h per labour-year.
- Over a 50-year operating period, approximately 600 administrative, operation and maintenance, and permanently contracted staff are employed annually.
- Once the reactor is shut down, a further 500 people are employed annually over a ten-year period of decommissioning. In addition, over a period of about 40 years, 80 employees manage nuclear waste.

In addition, several jobs are created through indirect employment for the nuclear supply chain, which are estimated to be approximately the same number as direct employment (ref. 3).

About SMR, a study shown that the concepts GT-MHR SMR- 285 MW and GT-MGR SMR- 262 MW require operation staff of about 230 and 166 respectively (ref. 11).

Research and development
The next generation of nuclear reactors are categorized as Generation IV. Designs for Generation IV are not expected to be operational before the mid-2020s. There are seven designs being considered as Generation IV. These are under development by the GIF (Generation IV International Forum), an international collective representing governments of 13 countries where nuclear energy is significant now and seen as vital for the future. The different reactors are summarized in the table below.

Reactor Type	Neutron Spectrum	Coolant	Temperature (°C)	Pressure	Fuel	Fuel Cycle	Size (MWe)	Use
Gas-cooled fast reactors	fast	helium	850	high	U-238 +	closed, on site	1200 & 1800+	electricity & hydrogen
Lead-cooled fast reactors	fast	lead or Pb-Bi	480-570	low	U-238 +	closed, regional	20-1800+	electricity & hydrogen
Molten salt fast reactors	fast	fluoride salts	700-800	low	UF in salt	closed	1000	electricity & hydrogen
Molten salt reactor - advanced high-temperature reactors	thermal	fluoride salts	750-1000	low	UO2 particles in prism	open	1000-1500	hydrogen
Sodium-cooled fast reactors	fast	sodium	500-550	low	U-238 & MOX	closed	50-1500	electricity
Supercritical water-cooled reactors	thermal or fast	water	510-625	very high	UO2	open (thermal), closed (fast)	300-1000	electricity
Very high temperature gas reactors	thermal	helium	900-1000	high	UO2 prism or pebbles	open	250-300	hydrogen & electricity

Generation IV reactors (ref. 2).

Additionally, more than a dozen (Generation III) advanced reactor designs are in various stages of development. One of these is called Advanced Boiling Water Reactor, a few of which are now operating and others are under construction. The best-known radical new design has fuel as large 'pebbles' and uses helium as coolant, at very high temperature, possibly to drive a turbine directly. Considering the closed fuel cycle, Generation I-III reactors recycle plutonium (and possibly uranium), while Generation IV are expected to have full actinide recycle. Many advanced reactor designs are for small units - under 300 MWe - and in the category of small modular reactors (SMRs), since several of them together may comprise a large power plant, may be built progressively.

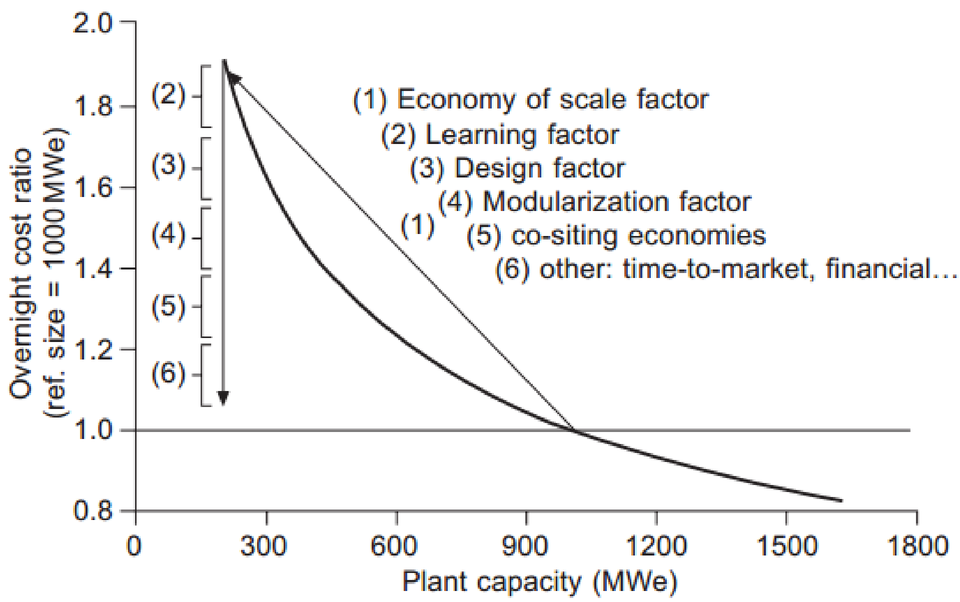
Investment cost estimate, overview
Large nuclear plants are seen as a category 3 or 4 technology, while the SMR should be seen as a category 2-3 meaning the estimates for SMR, are made with high uncertainty.

Large reactor: The overnight capital cost for a nuclear plant is dependent on various factors ranging from plant design, equipment, labour, and construction. The value for 2023 is considering the global context, under the assumption that the plant to be set up would most likely be a PWR, since it is the most commonly used technology today as seen in table below. The estimate lies in the conservative end accounting for latest project delays and cost reconsiderations in mature markets and to reflect the local market situation. The data are summarized in the table below.

Investment costs [$MUSD_{2022}$/MW]			2020	2023	2030	2050
Catalogues	**Technology catalogue (2023)**			9.0	7.9	6.8
International Data	Literature[1]		6.0-10.4			
	NREL ATB 2023 (moderate)			8.8-9.4	7.7-8.5	6.6-7.2
	IEA WEO 2023	(Average of USA and EU)		5.8	4.9	4.5
		(Average of China and India)		2.8	2.8	2.6
	Statista Survey 2023 Capital costs of energy generation in the US by source			8.4-13,9		
	EIA Capital Cost Study 2020		6.9			
Projection	Development curve – cost trend [%]			100%	87%	75%

[1] *O. NEA, "Unlocking Reductions in the Construction Costs of Nuclear: A Practical Guide for Stakeholders," 2020.*

Small modular reactor SMR: With very few SMR projects under construction and no actual data on overnight actual costs available, cost estimation of SMRs is usually performed on a top-down basis, starting from available information on large, advanced pressurized water reactor (PWR) units, as a starting reference cost:



(Ref. 12 and ref. 13) considers four plant sizes (1600 MWe, 1200 MWe, 300 MWe, 150 MWe) to compare the "economy of scale" and the "economy of multiples" paradigms and two scenarios: NPPs deployed by a big utility and two minors and NPPs deployed by a single utility. The main results are:

- By considering only the "economy of scale," the overnight cost of the first SMR (300 MWe) would be 89% higher than a single LR (1600 MWe);

- By considering not only the "economy of scale" but the "economy of replication" too, the gap reduces to 13%.
- If the Interest During Construction (IDC) is considered, the gap between SMRs (300 MWe) and LR (1600 MWe) reduces to 7% - 10%. Since the investment cost in the TC does not consider IDC the investment cost of SMR is calculated 13% higher than large reactors, consistent with the results in the study presented in (ref. 21).

Examples of current projects

Currently there are no conventional PWR or SMR Indonesian nuclear power plants. In the data sheets for PWR, data for South Korean and Japanese plants is used as a baseline. While for SMR the data is based on international sources and research. There are severel developers of SMR reactors who have showed interest in developing nuclear in Indonesia and have signed memorandums of understanding (MOU) with Indonesian developers. Thorcon, has signed an agreement to license a 500 MW molten salt reactor in Indonesia, aiming to start operation on Gelasa Island. As of 2023 construction has not started yet. Danish SMR companies Seaborg and Copenhagen Atomics have in 2023 signed MOUs with Pertamina NRE to investigate and do feasibility studies on floating and land based SMR respectively. Both projects are still early in development.

Currently, there are two SMR power plants in operation, one in Russia and one in China. Some details about the two plants are given below.

SMR: KLT-40 in Russia (marine-based) (ref. 14)

The KLT-40S (Akademik Lomonosov) is a PWR developed for a floating nuclear power plant (FNPP) to provide capacity of 35 MW(e) per module. The design is based on third generation KLT-40 marine propulsion plant and is an advanced version of the reactor providing the long-term operation of nuclear icebreakers under more severe conditions as compared to stationary nuclear power plant (NPP).

KLT-40: Major technical parameters	
Parameter	**Value**
Technology developer, country of origin	JSC "Afrikantov OKBM", Rosatom, Russian Federation
Reactor type	PWR
Coolant/moderator	Light water/light water
Thermal/electrical capacity, MW(t)/MW(e)	35/35
Primary circulation	Forced circulation
NSSS Operating pressure (primary/secondary), MPa	12.7
Core inlet/outlet coolant temperature (°C)	280/316
Fuel type/assembly array	UO2 pellet in zirconium matrix
Number of fuel assemblies in the core	121
Fuel enrichment (%)	18.6
Core discharge burnup (GWd/ton)	45.5
Refuelling cycle (months)	30-36
Reactivity control mechanism	Control rod driving mechanism
Approach to safety systems	Active (partially passive)
Design life (years)	40
Plant footprint (m^2)	4320 (Floating NPP)
RPV height/diameter (m)	4.8 / 2.0

RPV weight (metric ton)	9
Seismic design (SSE)	9 point on the MSK scale
Distinguishing features	Floating power unit for cogeneration of heat and electricity; no onsite refuelling; spent fuel take back.
Design status	Connected to the grid in Pevek in December 2019. Entered full commercial operation.

ACP-100 in China (land-based) (ref. 14)

The ACP100 is an integrated PWR design developed by China National Nuclear Corporation (CNNC) to generate an electric power of 125 MW(e). The ACP100 is based on existing PWR technology adapting verified passive safety systems to cope with the consequences of accident events; in case of transients and postulated design basis accidents the natural convection cools down the reactor. The ACP100 integrated design of its reactor coolant system (RCS) enables the installation of the major primary circuit's components within the reactor pressure vessel (RPV).

MAJOR TECHNICAL PARAMETERS	
Parameter	**Value**
Technology developer, country of origin	CNNC(NPIC/CNPE) China
Reactor type	Integral PWR
Coolant/moderator	Light water / light water
Thermal/electrical capacity, MW(t)/MW(e)	385 / 125
Primary circulation	Forced circulation
NSSS Operating Pressure (primary/secondary), MPa	15 / 4.6
Core Inlet/Outlet Coolant Temperature (ºC)	286.5 / 319.5
Fuel type/assembly array	UO_2/17x17 square pitch arrangement
Number of fuel assemblies in the core	57
Fuel enrichment (%)	<4.95
Core Discharge Burnup (GWd/ton)	<52 000
Refuelling Cycle (months)	24
Reactivity control mechanism	Control rod drive mechanism (CRDM), Gd_2O_3 solid burnable poison and soluble boron acid
Approach to safety systems	Passive
Design life (years)	60
Plant footprint (m^2)	200 000
RPV height/diameter (m)	10 / 3.35
RPV weight (metric ton)	300
Seismic Design (SSE)	0.3g
Fuel Cycle Requirements or Approach	Temporarily stored in spent fuel pools
Distinguishing features	Integrated reactor with tube-in-tube once through steam generator, nuclear island

Furthermore, in China one of two HTR-PM reactors of 100 MW, have started generating electricity to the grid 20 December 2021.The construction of the first of the two HTR-PMs was originally planned to happen before 2010, while a study claimed that the cost would not exceed a conventional pressurized water reactor by more than 20 percent. Construction only began in 2012, and by then the time estimate for construction had increased to '50 months'. In reality, the first unit took almost 109 months from first concrete to mains connection, more than twice as long as expected. (ref. 14.).

SMR project in Idaho USA, 6 x 77 MW, has been stopped in November 2023, but the project development started in 2000. In 2013 it was decided that the company Nuscale should build six small modular nuclear reactors, SMRs, in Idaho, USA. In 2022 the US Nuclear Safety Authority approved the construction of NuScale's reactor design in the US. It was announced by Nuscale, that the six reactors with a total of 462 MW would be up and running in 2030. In November 2023 the project is stopped due to increasing cost. Mid-2021, the target price for power was assumed to be 58 $/MWh, however, in January 2023 it was risen to 89$/MWh, including a $1.4 billion contribution from the U.S. Department of Energy from the Inflation Reduction Act, reducing the power target price by 30$/MWh. The higher target price is due to a 75% increase in the estimated construction cost for the project, from $5.3 to $9.3 billion dollars (increasing the investment cost from 11.5 M$/MW to 20.1 M$/MW). The increase explained to be due to inflationary pressures on the energy supply chain specifying increases on the Producer Price Index for steel, electrical equipment, copper wire and cable. Producer Price Index for All Commodities increased 45% (Ref 22-26), meaning that 30% of the 75% increase in CAPEX cannot be explained by increase in Producer Price Index.

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Data sheets

The following pages content the data sheets of the technology. All costs are stated in U.S. dollars (USD), price year 2022. The uncertainty is related to the specific parameters and cannot be read vertically - meaning a product with lower efficiency does not have the lower price or vice versa.

Technology

Technology	Nuclear power plant - PWR								
	2023	2030	2050	Uncertainty (2023)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	1000	1000	1000						
Generating capacity for total power plant (MWe)	2000	2000	2000					B	
Electricity efficiency, net (%), name plate	37	38	42					C	4
Electricity efficiency, net (%), annual average	34	36	40					C	4
Forced outage (%)	2	2	2						4
Planned outage (weeks per year)	9%	8%	6%						4
Technical lifetime (years)	60	60	60						1,4
Construction time (years)	7.4	7.4	7.4	4.0	10.0				1,4
Space requirement (1000 m^2/MWe)	2.6	2.6	2.6	2.0	3.4	2.0	3.4	D	8,9
Additional data for non thermal plants									
Capacity factor (%), theoretical									
Capacity factor (%), incl. outages									
Ramping configurations									
Ramping (% per minute)	4	4	3	3	5			A	5,4
Minimum load (% of full load)	25	25	25					A	5
Warm start-up time (hours)	2	2	1	2	6				5
Cold start-up time (hours)	30	30	30	24	48				4
Environment									
PM 2.5 (mg per Nm^3)	-	-	-						
SO_2 (degree of desulphuring, %)	-	-	-						
NO_x (g per GJ fuel)	-	-	-						
CH_4 (g per GJ fuel)	-	-	-						
N_2O (g per GJ fuel)	-	-	-						
Financial data									
Nominal investment (M$/MWe)	9.00	7.90	6.80	7.00	12.00	5.00	10.00	E,F,G	2,3,7,10
- of which equipment	33%	33%	33%					F	
- of which installation	67%	67%	67%					F	
Fixed O&M ($/MWe/year)	127,000	120,000	113,000	20,000	180,000	20,000	180,000		2,3
Variable O&M ($/MWh)	2.40	2.30	2.20	1.80	3.00	1.65	2.75	I	2,3,7
Start-up costs ($/MWe/start-up)	-	-	-						

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Notes:

A Ramping and minimum load are constrained by the core stability'. Minimum requirements are usually set by the regulation.

B A two-unit configuration is typical in nuclear power plants, but more units can be combined.

C Generation IV reactors are expected to achieve efficiencies well above 45%. In the future, nuclear reactors are likely' to run often at partial load - thus the gap between nameplate and net efficiency

D Nuclear power plants have a very' high energy' density' in terms of area required. The values represented here are for the area needed for the plants. However, there can be a higher requirement based on government regulation and environmental concerns F High variation in cost seen between US. EU costs and China. India costs. Moreover, this

E Decommissioning costs usually are the 15% of the total investment cost, is not included in the onvestment cost

F The CAPEX breakdown is composed by 33% share of direct cost (i.e., Equipment, Labour, Construction, Materials and Building), 37% of Indirect cost (i.e., Design services, Construction and Supervision and project management, Commissioning and startup costs), 17% of Financial costs, 10% of Owner's cost.

G The development of the overnigth cost is based on NREL ATB 2023

H CAPEX is in line with NREL ATB 2023 (overnight capital costs + construction financing costs)

I Uncertainty (Upper/Lower) is estimated as +/- 25%.

Technology

Technology	Nuclear power plant - SMR (Land based Water-cooled)								
	2023	2030	2050	Uncertainty (2023)		Uncertainty (2050)		Note	Ref
Energy/technical data									
Generating capacity for one unit (MWe)	80	80	80						2,3,4
Generating capacity for total power plant (MWe)	300	300	300	10	300	10	300		2,3,4
Electricity efficiency, net (%), name plate	27	27	30					B	2
Electricity efficiency, net (%), annual average	27	27	30					B	2,1,4
Forced outage (%)	3	3	3						2,1
Planned outage (weeks per year)	6.5%	6.0%	5.0%	3.0%	7.0%				2
Technical lifetime (years)	30	40	50						2,3
Construction time (years)	9	8	4	8	12	4	12	G	2,3, 13
Space requirement (1000 m^2/MWe)	0.64	0.64	0.64	0.04	1.60	0.04	1.60	C	11
Additional data for non thermal plants									
Capacity factor (%), theoretical									
Capacity factor (%), incl. outages									
Ramping configurations									
Ramping (% per minute)	1.2	1.2	1.2					A	2.5
Minimum load (% of full load)	25	25	20					A	1,2,5
Warm start-up time (hours)	1.5	1.5	1.5						2.5
Cold start-up time (hours)	24	24	24						
Environment									
PM 2.5 (mg per Nm^3)	-	-	-						
SO_2 (degree of desulphuring, %)	-	-	-						
NO_x (g per GJ fuel)	-	-	-						
CH_4 (g per GJ fuel)	-	-	-						
N_2O(g per GJ fuel)	-	-	-						
Financial data									
Nominal investment (M$/MWe)		9.60	7.30	5.60	20.00	5.00	10.00	D,E	8,10,12,13
- of which equipment		33%	33%						2,3,6
- of which installation		67%	67%						2,3,6
Fixed O&M ($/MWe/year)		110,000	102,000						2,3,6
Variable O&M ($/MWh)		2.20	2.10					F	2,3,6
Start-up costs ($/MWe/start-up)									

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Notes:

A Ramping and minimum load are constrained by the core stability'. Minimum requirements are usually set by the regulation.

B Generation IV reactors are expected to achieve efficiencies well above 45%. In the future, nuclear reactors are likely' to run often at partial load - thus the gap between nameplate and net efficiency

C Nuclear power plants have a ' high energy' density' in terms of area required. The values represented here are for the area needed for the plants. However, there can be a higher requirement based on government regulation and environmental concerns F High variation in cost seen between US. EU costs and China. India costs. Moreover, this also depends on technology'. Here the chosen values are estimated based on a mix of values available along with employing the learning curve approach used for financial parameters.

D Decommissioning costs usually are the 15% of the total investment cost

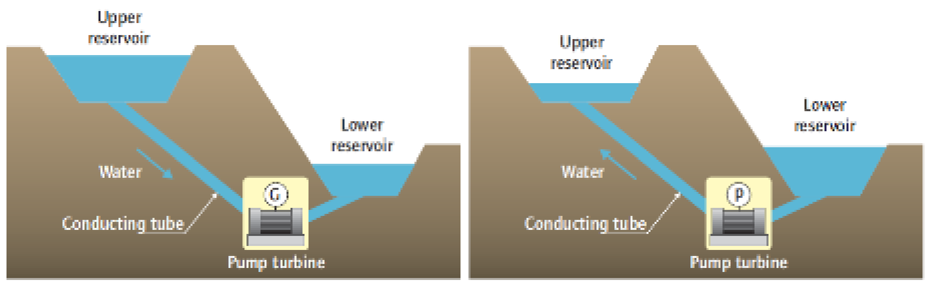
E The CAPEX breakdown is composed by 33% share of direct cost (i.e., Equipment, Labour, Construction, Materials and Building), 37% of Indirect cost (i.e., Design services, Construction and Supervision and project management, Commissioning and startup costs), 17% of Financial costs, 10% of Owner's cost.

F The main characteristic are taken from CAREM-25

G +109 mdr: China, however, managed to connect its first SMR, one of two 100 MW HTR-PM reactors, to the grid on 20 December 2021.Construction only began in 2012, and by then the time estimate for construction had increased to '50 months'. In reality, the first unit took almost 109 months from first concrete to mains connection, more than twice as long as expected

20. Pumped-Hydro Energy Storage

Brief technology description
Pumped storage plants (PSPs) use water that is pumped from a lower reservoir into an upper reservoir when electricity supply exceeds demand or can be generated at low cost. When demand exceeds instantaneous electricity generation and electricity has a high value, water is released to flow back from the upper reservoir through turbines to generate electricity. Pumped storage plants take energy from the grid to lift the water up, then return most of the electricity later (round-trip efficiency being 70% to 85%). Hence, PSP is a net consumer of electricity but provides for effective electricity storage. Pumped storage currently represents 99% of the world's on-grid electricity storage (ref. 1).



Source: Inage, 2009.

Pumped storage hydropower plants (ref. 2)

A pumped storage project would typically be designed to have 6 to 20 hours of hydraulic reservoir storage for operation. By increasing plant capacity in terms of size and number of units, hydroelectric pumped storage generation can be concentrated and shaped to match periods of highest demand, when it has the greatest value. Both reservoir and pumped storage hydropower are flexible sources of electricity that can help system operators handle the variability of other renewable energy sources such as wind power and photovoltaic electricity.

There are three types of pumped storage hydropower (ref. 3):

- Open loop: systems that developed from an existing hydropower plant by addition of either an upper or a lower reservoir. They are usually off stream.
- Pump back: systems that are using two reservoirs in series. Pumping from the downstream reservoir during low-load periods making additional water available to use for generation at high demand periods.
- Closed loop: systems are completely independent from existing water streams – both reservoirs are off-stream.

Pumped storage and conventional hydropower with reservoir storage are the only large-scale, low-cost electricity storage options available today. Pumped storage power plants are currently less expensive than Li-ion batteries. However, pumped storage plants are generally more expensive than conventional large hydropower schemes with storage, and it is often very difficult to find good sites to develop pumped hydro storage systems.

Interest in pumped storage is increasing, particularly in regions and countries where solar PV and wind are reaching relatively high levels of penetration and/or are growing rapidly (ref. 5). The vast majority of current pumped storage capacity is located in Europe, Japan and the United States (ref. 5).

Currently, pumped storage capacity worldwide amounts to about 140 GW. In the European Union, there are 45 GWe of pumped storage capacity. In Asia, the leading pumped hydropower countries are Japan (30 GW) and China (24 GW). The United States also has a significant volume of the pumped storage capacity (20 GW) (ref. 6).

In Indonesia, even though there is no operational capacity installed yet with a very large project being currently under construction, the potential for pumped hydro storage amounts to roughly 7,300 GWh according to IESR estimation.

Input
Electricity

Output
Electricity

Typical capacities
50 to 500 MW per unit (ref. 12)

Ramping configurations
Storage possibilities combined with the instant start and stop of generation makes hydropower very flexible. Pumped storage plants, such as the Grand Maison power station in France, can ramp-up up to 1800 MW in only three minutes. This equals 600 MW/min (ref. 11).

Pumped storage hydropower plants have a fast load gradient (i.e. the rate of change of nominal output in a given timeframe) as they can ramp up and down by more than 40% of the nominal output per minute. Pumped storage and storage hydro with peak generation can cope with high generation-driven fluctuations and can provide active power within a short period of time. Below, some flexibility parameters for different types of pumped-hydro.

Capability	Fixed-Speed PSH	DFIM Adjustable-Speed PSH	Ternary PSH with Hydraulic Bypass and Pelton Turbine
Generation Mode:			
Power output (% of rated capacity)	30%[a]–100%	20%–100%	0%–100%
Standstill to generating mode (seconds)	75–90	75–85	65
Generating to pumping mode (seconds)	240–420	240–415	25
Frequency regulation	Yes	Yes	Yes
Spinning reserve	Yes	Yes	Yes
Ramping/load following	Yes	Yes	Yes
Reactive power/voltage support	Yes	Yes	Yes
Generator dropping	Yes	Yes	Yes
Pumping Mode:			
Power consumption (% of rated capacity)	100%	60%–100% (75%–125%)[b]	0%–100%
Standstill to pumping mode (seconds)	160–340	160–230	80
Pumping to generating mode (seconds)	90–190	90–190	25
Frequency regulation	No	Yes	Yes
Spinning reserve	No	Yes	Yes
Ramping/load following	No	Yes	Yes
Reactive power/voltage support	Yes	Yes	Yes
Load shedding	Yes	Yes	Yes

Pumped storage characteristics and services. Source: US Department of Energy, 2019.

The ability of pumped-hydro storage plants to provide services such as frequency regulation, spinning reserve, load following and ramping, voltage support, as well as time shifting services, makes them a viable option to support the increasing penetration of variable renewable energy sources like PV and wind.

Advantages/disadvantages

Advantage:

- The flexibility of the pumped-hydro plants and their storage nature can help with the integration of variable renewable energies like PV and wind.
- The water can be reused repeatedly, thus smaller reservoirs are suitable.
- The process of electricity generation (discharging) has no emissions.
- Water is a renewable source of energy.
- The reservoirs can be used for additional purposes like water supply, fishing and recreation (ref. 15).

Disadvantages:

- Very limited locations.
- Cost of infrastructure.
- The time it takes to construct is longer than other energy storage options.
- The construction of dams in rivers always has an impact on the local environment.

Environment

The possible environmental impacts of pumped storage plants have not been systematically assessed but are expected to be small. The water is largely reused, limiting extraction from external water bodies to a minimum. Using existing dams for pumped storage may result in political opportunities and funding for retrofitting devices and new operating rules that reduce previous ecological and social impacts (ref. 8). PSP projects require small land areas, as their reservoirs will in most cases be designed to provide only hours or days of generating capacities.

Employment

PLN expected that the Upper Cisokan hydro power plant (pumped storage) would need around 3000 workers to complete. According to current regulation on manpower, two thirds of those workers must be selected from local work force.

Research and development

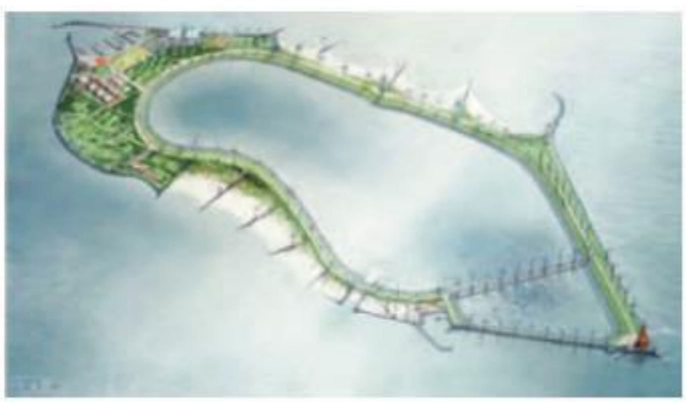
Hydro pumped storage is, like hydro reservoir power, a well-known and mature technology – i.e. category 4.

Under normal operating conditions, hydropower turbines are optimized for an operating point defined by speed, head and discharge. At fixed-speed operation, any head or discharge deviation involves some decrease in efficiency. Variable-speed pump-turbine units operate over a wide range of head and flow, improving their economics for pumped storage. Furthermore, variable-speed units accommodate load variations and provide frequency regulation in pumping mode (which fixed-speed reversible pump-turbines provide only in generation mode). The variable unit continues to function even at lower energy levels, ensuring a steady refilling of the reservoir while helping to stabilize the network.

Pumped storage plants can operate on seawater, although there are additional challenges involved compared to operation with fresh water. The 30 MW Yanbaru project in Okinawa was the first demonstration of seawater pumped storage. It was built in 1999 but finally dismantled in 2016 since it was not economically competitive. A 300 MW seawater-based project has recently been proposed on Lanai, Hawaii, and several seawater-based projects have been proposed in Ireland and Chile.

A 300 MW sea water pumped storage hydropower plant in Chile (ref. 13)

A Dutch company, Kema, has further developed the concept of an "Energy Island" to be build off the Dutch coast in the North Sea. It would be a ring dyke enclosing an area 10 km long and 6 km wide (see figure below). The water level in the inner lake would be 32 metres to 40 metres below sea level. Water would be pumped out when electricity is inexpensive, and generated through a turbine when it is expensive. The storage potential would be 1 500 MW by 12 hours, or 18 GWh. It would also be possible to install wind turbines on the dykes, so reducing the cost of offshore wind close to that of onshore, but still with offshore load factors.



Concept of an energy island (ref. 9)

In Germany, RAG, a company that exploited coal mines, is considering creating artificial lakes on top of slag heaps or pouring water into vertical mine shafts, as two different new concepts for PSP (ref. 10)

Examples of current projects

The Fengning Pumped Storage Power Station is a pumped-storage hydroelectric power station currently under construction about 145 km (90 mi) northwest of Chengde in Fengning Manchu Autonomous County of Hebei Province, China. Construction on the power station began in June 2013 and the first generator is expected to be commissioned in 2019, the last in 2021. Project costs are US$1.87 billion. On 1. April 2014, Gezhouba Group was awarded the main contract to build the power station. When complete, it will be the largest pumped-storage power station in the world with an installed capacity of 3600 MW which consists of 12 x 300 MW Francis pump turbines (ref. 14).

In Indonesia currently, a pumped storage hydropower plant project is under construction in West Bandung and Cianjur Regency, West Jawa. The project is called Upper Cisokan Pumped Storage Power Plant. After receiving funding from the World Bank, construction on major works began in 2019 and the first generator is expected that all generators will be commercially operational in 2025. It will have an installed capacity of 1,040 MW and will be Indonesia's first pumped-storage power plant. As a pumped-storage power plant, the project includes the creation of an upper and lower reservoir; the lower reservoir will be on the Upper Cisokan River a branch of Citarum River while the upper reservoir will be on the Cirumanis River, a branch of the Cisokan River. The power plant will contain four Francis pump-turbines which are rated at 260 MW each for power generation and 275 MW for pumping. The upper reservoir will lie at maximum elevation of 796 m and the lower at 499 m. This difference in elevation will afford the power plant a rated hydraulic head of 276 m. (ref 16).

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Data sheets

The following pages content the data sheets of the technology. All costs are stated in U.S. dollars (USD), price year 2022. The uncertainty is related to the specific parameters and cannot be read vertically - meaning a product with lower efficiency does not have the lower price or vice versa.

Technology

Technology	Hydro pumped storage								
	2023	2030	2050	Uncertainty (2023)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	250	250	250	100	500	100	500	A	1,6
Generating capacity for total power plant (MWe)	1000	1000	1000	100	4000	100	4000		1,6
Electricity efficiency, net (%), name plate	80	80	80	75	82	75	82		1,3,5
Electricity efficiency, net (%), annual average	80	80	80	75	82	75	82		1,3,5
Forced outage (%)	4	4	4	2	7	2	7		5
Planned outage (weeks per year)	3	3	3	2	6	2	6		5
Technical lifetime (years)	60	60	60	50	90	40	90		1
Construction time (years)	6.0	5.0	4.0	3.0	9.0	2.0	6.0	B	1
Space requirement (1000 m^2/MWe)	30	30	30	15	45	15	45		1
Additional data for non thermal plants									
Capacity factor (%), theoretical	-	-	-	-	-	-	-	F	
Capacity factor (%), incl. outages	-	-	-	-	-	-	-		
Ramping configurations									
Ramping (% per minute)	50	50	50	10	100	10	100		2,5
Minimum load (% of full load)	0	0	0	0	0	0	0		2
Warm start-up time (hours)	0.1	0.1	0.1	0.0	0.3	0.0	0.3		2
Cold start-up time (hours)	0.1	0.1	0.1	0.0	0.3	0.0	0.3		2
Environment									
PM 2.5 (gram per Nm^3)	0	0	0						
SO_2 (degree of desulphuring, %)	0	0	0						
NO_X (g per GJ fuel)	0	0	0						
CH_4 (g per GJ fuel)	0	0	0						
N_2O (g per GJ fuel)	0	0	0						
Financial data									
Nominal investment (M$/MWe)	1.20	1.20	1.20	0.60	6.0	0.60	6.0	C,E	1,3,4,8
- of which equipment	30%	30%	30%	20%	50%	20%	50%		7
- of which installation	70%	70%	70%	50%	80%	50%	80%		7
Fixed O&M ($/MWe/year)	18,700	18,700	18,700	4,000	30,000	4,000	30,000		4
Variable O&M ($/MWh)	0.94	0.94	0.94	0.5	3.0	0.5	3.0		1,4
Start-up costs ($/MWe/start-up)	-	-	-	-	-	-	-		
Technology specific data									
Size of reservoir (MWh)	10,000	10,000	10,000	3,000	20,000	3,000	20,000	D	1,6,9
Load/unload time (hours)	10	10	10	4	12	4	12	D	1,6,9

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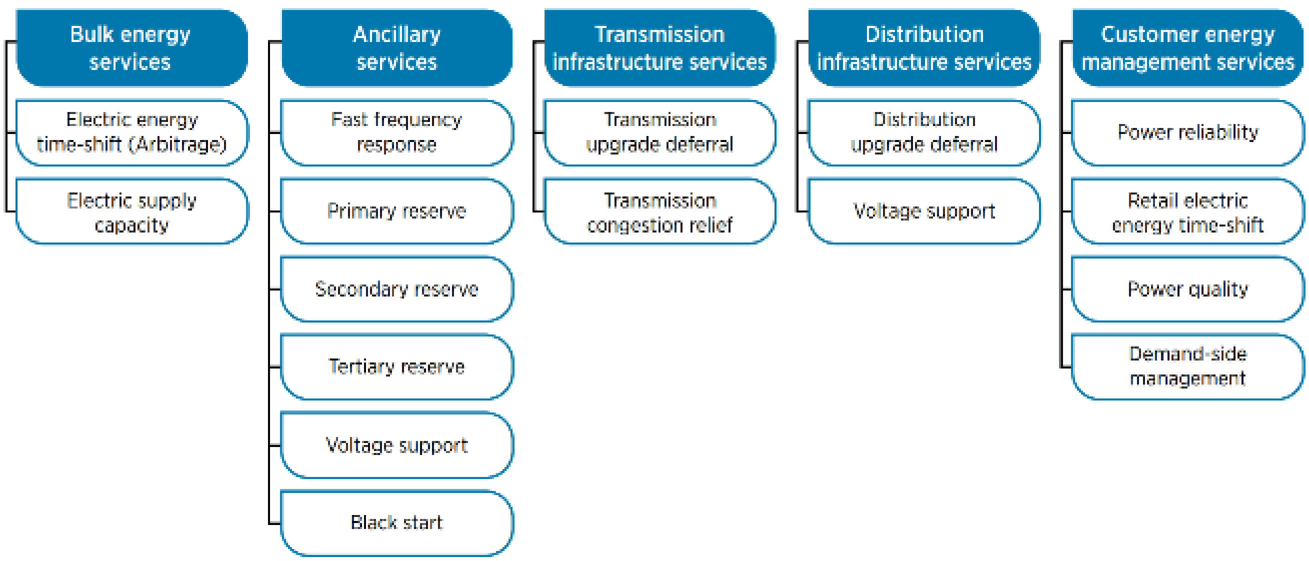
Notes:
A Size per turbine.
B Uncertainty (Upper/Lower) is estimated as +/- 50%.
C Numbers are very site sensitive. There will be an improvement by learning curve development, but this improvement will equalized because the best locations will be utilized first. The investment largely depends on civil work.
D The size of the total power plant and not per unit (turbine).
E Investment cost include the engineering, procurement and construction (EPC) cost. See description under Methodology.

21. Battery Energy Storage Systems

Brief technology description

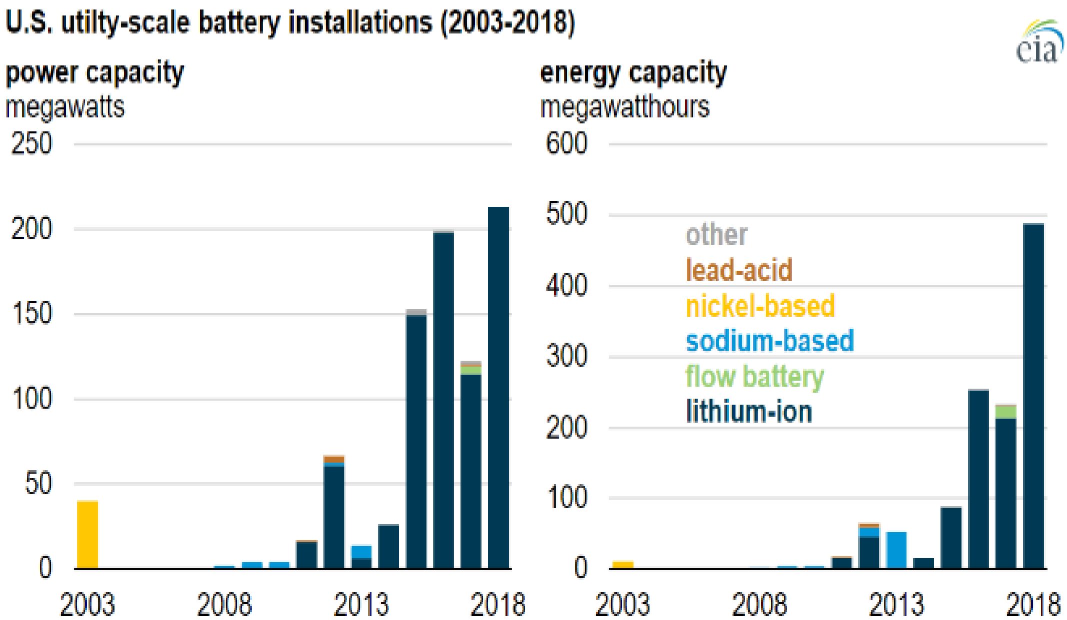
With increasing shares of variable renewable energy in power systems, the role of electricity storage grows in importance. Among all technologies, batteries (electrochemical storage) have experienced notable cost declines in the past years. This is especially true for certain battery types; this catalogue considers the Li-Ion type, which has been used in different grid applications around the world. The potential applications of batteries in electricity systems are very broad, ranging from supporting weak distribution grids, to the provision of bulk energy services or off-grid solutions (see figure below).

This technology description focuses on batteries for provision of *bulk energy services* and *customer energy management services*, i.e. time-shift over several hours (arbitrage) – for example moving PV generation from day to night hours –, the delivery of peak power capacity, demand-side management, power reliability and quality.



Range of services electricity storage can provide (ref. 41).

Other kinds of electrochemical storage that have reached commercialization today include lead-acid, high temperature sodium sulphur (NaS), sodium nickel chloride and flow battery technologies (vanadium redox flow). Lithium-ion batteries (LIB) have however completely dominated the market for grid scale energy storage solutions in the last years and appear to be the dominating battery solution (see figure below for the US). For this reason, this chapter focuses on LIB.



Utility-scale battery installations by type in the US (2003-18). Source: EIA.

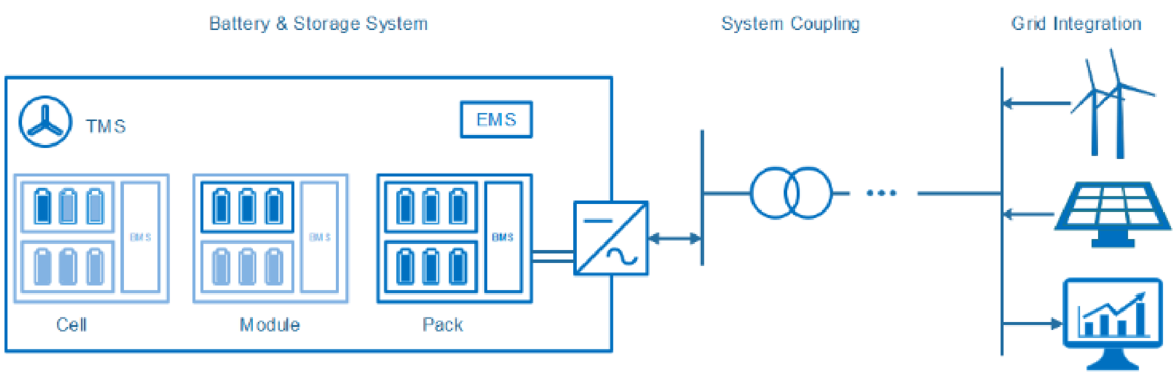
A typical LIB installed nowadays has a graphitic anode, a lithium metal oxide cathode and an electrolyte that can be either liquid or in (semi-)solid-state. When liquid, it is composed of lithium salts dissolved in organic carbonates; when solid, lithium salts are embedded into a polymeric matrix. Three major types of Li-Ion batteries installed nowadays for utility-scale storage are reported in the table below. Li-Ion batteries commonly come in packs of cylindrical cells and can reach energy densities of up to 300 Wh/kg. The spaced required for the LiB is around 5 m^2/MWh.

Short name	**Name**	**Anode**	**Cathode**	**Energy density Wh/kg**	**Cycles**	**Calendar life**	**Major manufactures**
NMC	Lithium Nickel Manganese Cobalt Oxide	Graphite	Li $Ni_{0.6}Co_{0.2}Mn_{0.2}O_2$	120-300	3000-10000	10-20 years	Samsung SDI LG Chem SK Innovation Leclanche Kokam
LFP	Lithum Iron Phosphate	Graphite	$LiFePO_4$	50-130	6000-8000	10-20 years	BYD/Fenecon Fronius/Sony*
LTO	Lithium Titanate	$LiTO_2$	$LiFePO_4$ or Li $Ni_{0.6}Co_{0.2}Mn_{0.2}O_2$	70-80	15000-20000	25 years	Leclanche Kokam Altairnano

Major LIB types in use for utility-scale storage.

Electrons flow in the external circuit and Li ions pass through the electrolyte. The charging and discharging of the battery depend on the shuttling mechanism of Li-ions between anode and cathode. This process is controlled by an electronic battery management system to optimize cell utilization and degradation, while delivering the desired loading/unloading current. The fast Li-ion transport and the small diffusion distance due to the lamellar architecture of components inside the cell ensure that the response time for LIB is very low (ref. 1). It also has a low self-discharge rate of only 0.1–0.3% per day and good cycle efficiency of up to 97% (ref. 8).

A schematic overview of a battery system and its grid connection can be seen in the figure below. A Thermal Management System (TMS) controls the temperature in the battery packs to prevent overheating and thermal runaway (the phenomenon is explained in the following). The Energy Management System regulates the energy exchange with the grid. Power electronics convert DC into AC before power is injected into the grid. In some cases (high-voltage grids), a transformer might be required to feed electricity into the grid.



Schematic illustration of a battery storage system and its grid connection.

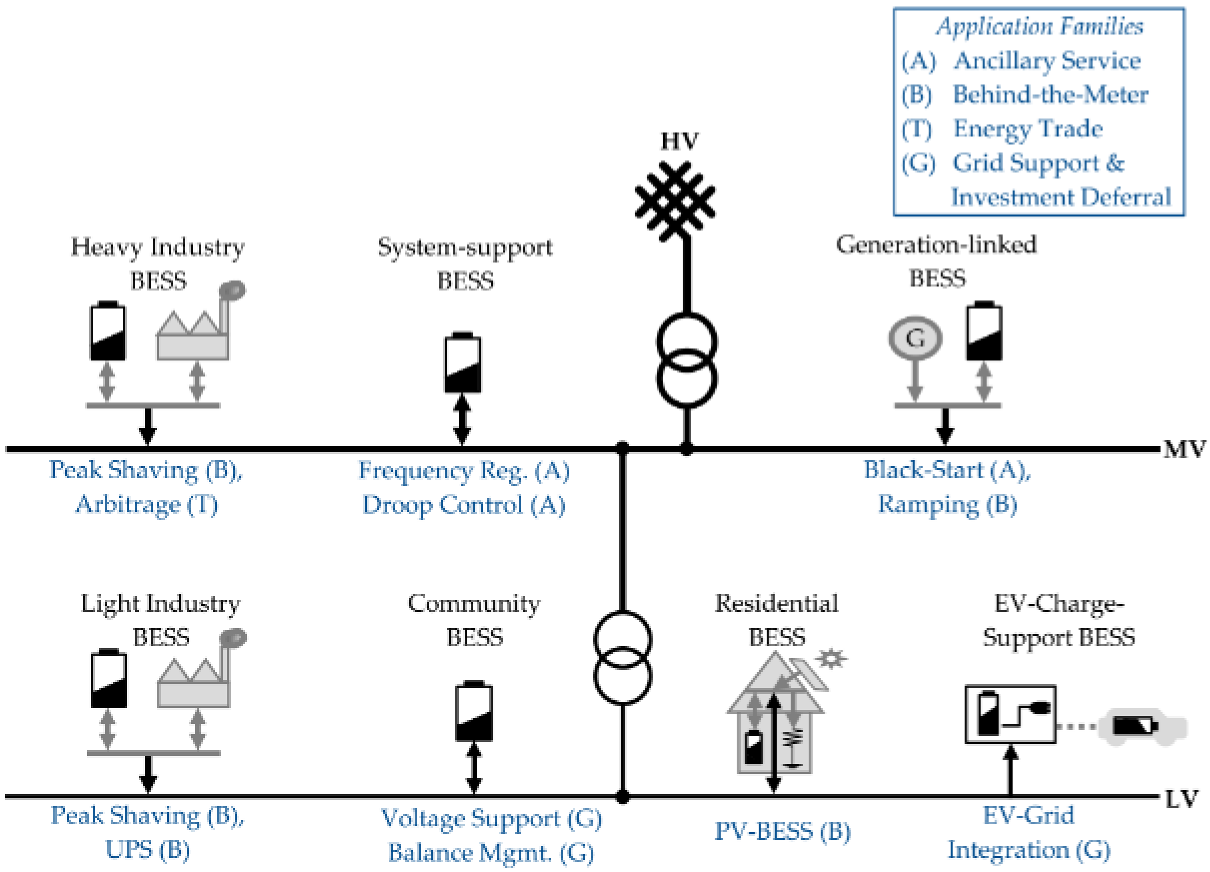
Charging and discharging rates of LIB are often measured with the C-rate, which is the maximum capacity the battery can deliver with respect to its energy storage. Thereby 1 hour divided by the C rate is the minimum charging or discharging time. For example, a battery with a C rate of 3C can be discharged in 20 minutes, of 1C can be discharged in 1 hour and of ½ C can be discharged 2 hours. Operations at higher C-rates than specified in the battery pack are possible but would lead to a faster degradation of the cell materials (ref. 9). Generally, for the same chemistry/construction, a battery going through a 15-minute full discharge will have a lower cycle life (and thereby lifetime) than a similar battery used for a 1-hour full discharge cycle.

LIB do not suffer from the memory effect issue (the effect of batteries gradually losing their maximum energy capacity if they are repeatedly recharged after being only partially discharged) and can be used for variable depths of discharge at short cycles without losing capacity (ref. 11). The relationship between battery volume (in MWh) and loading/unloading capacity (in MW) can be customized based on the system needs and in order to obtain a better business case.

The lifetime of battery energy technologies is better measured by the total number of cycles undergone over the lifetime. Nowadays, a Li-Ion battery typically endures around 10000 full charge/discharge cycles. Batteries generate DC current, which then needs to be converted into AC to be fed into the most interconnected grids. This is achieved through power electronics (inverters).

As mentioned at the beginning of this section, battery energy storage systems (BESS) can have manifold applications and thus can be installed at different voltage levels (see figure below). BESS architecture is ultimately shared across use types, with minor differences depending on the single applications. In off- and micro-grid contexts (not represented in the figure below), grid connection costs are reduced totally or partially.

Industry and households can install batteries behind the meter to reshape the own load curve and to integrate distributed generation such as rooftop or industrial PV. The major benefits are related to retail tariff savings, peak tariff reduction, reliability and quality of supply (ref. 43). Batteries can boost the self-consumption of electricity and back up the local grid by avoiding overload and by deferring new investments and reinforcements. In case of bi-directional flows to/from the grid (prosumption), BESS can increase the power quality of distributed generation and contribute to voltage stability. In developed market settings, these functions might not only reflect requirements enforced by the regulation, but also materialize in remunerated system services.



Different uses of battery systems depending on voltage level and application families (ref. 43).

Input
Electricity.

Output
Electricity.

Energy efficiency and losses
The roundtrip efficiency of Li-ion battery cells is close to 100%. However, there is several sources for losses, which can be grouped into operational and stand-by losses.

Operational losses are related to the power electronics and to the circuit resistance in the LIB and they increase with the second power of the current flowing in the battery's external circuit.

Stand-by losses are the result of unwanted chemical reactions in the battery (*self-discharge rate*). Self-discharge rates increase with temperature but can be assumed to be in the order of 0.1% of the energy content per day. Auxiliaries (thermal management system, energy management system) require energy to run as well, and losses therein must be accounted for as well.

AC-DC conversion and energy demand from the control electronics lead to a grid-to-grid efficiency (AC-AC) of about 90%. Frequency regulation requires fast short-cycle charge-discharge and reduces round-trip efficiency. Extensive cycling also reduces the lifetime of batteries. Overall, the round-trip efficiency can be expressed as a decreasing function of the C-rate, that is the capacity (max discharging) of battery compared to its' rated storage capacity.

Typical capacities
For bulk energy services, Li-Ion batteries come in large sizes. Small utility scale batteries are in the order of 1 to 10 MW and MWh, while large utility scale batteries can reach more than hundred MW and MWh. For example, in Australia many utility scale batteries have been connected to the national grid, the latest (August 2023) in a slew of big battery projects in recent months. These include French renewables giant Engie's 150 MW/150 MWh Hazelwood battery in Victoria, and the 250 MW/250 MWh Torrens Island and 41 MW/412 MWh Tailem Bend batteries in South Australia(ref.52). For distributed applications, battery size can range from a few kW to hundreds of kW.

For bulk energy services applications (for instance time shifting), several hours of storage might be needed, depending on the system needs. For example, an AES installed LIB facility in San Diego can feed the grid 37.5 MW of power continuously for 4 hours. This tendency will increase in the future with the necessity of moving variable renewable energy generation over long time frames.

Ramping configurations
Li-ion batteries (LIB) installations are flexible in terms of power/energy capacity and time of discharge. It has a response time in the order of milliseconds (determined by the inverter), which makes it suitable for the wide range of applications mentioned before, including power quality.

Advantages/disadvantages
Advantages/disadvantages are considered in relation to other battery technologies.

Advantages:

- Li-ion batteries (LIB) modules do not need particular maintenance and can work in harsh environments, thus operational costs are contained.

- LIB have a relatively high energy and power density.
- Round-trip energy efficiency is remarkably high for LIB among commercially scalable batteries. Other batteries have efficiency 10% lower or more. Some batteries like NiCd/Ni-MH lose energy capacity if not fully discharged. This is called memory effect. LIB do not suffer from memory effect and have low self-discharge.
- The combination of high power and energy density and the very short response time (few milliseconds) enables the usage of LIB in both power intensive applications such as frequency regulation and energy intensive applications like time shifting of dispatch. Li-Ion batteries can therefore benefit from different revenue streams, associated with a set of system services. The lack of memory effect allows short and deep discharging.
- LIB have a relatively long lifetime compared to many other battery types. This strengthens the business case and the financial viability of battery storage systems, since it lowers the levelized cost of storage.

Disadvantages:
Li-ion batteries (LIB) have a number of technical disadvantages, mainly related to electrochemical reactions within the cells.

- Electrode materials are prone to degradation if overcharged and deeply discharged repeatedly. A proper management system can effectively mitigate this problem.
- Continuous cycling lowers the overall lifetime of the battery.
- Li-Ion battery systems need cooling to remove the heat released by the battery modules. The auxiliary consumption needed for cooling can be sizeable depending on the type of application and battery use. Safety issues from thermal runaway are of concern. Thermal runaway arises as a consequence of high temperatures in the battery cells; within milliseconds, the energy content in the battery is emptied out and unacceptably high temperatures are reached. Li-ion batteries can charge in the 0-45°C temperature range, discharge even at slightly higher temperatures; thermal runaway can start already at 60°C. Overcharging is a cause of thermal runaway.
- The electrolyte has a limited electrochemical stability window. Beyond this limit, a redox reaction takes place between the oxygen released from the cathode and the electrolyte; the battery might catch fire (ref. 21). During a thermal runaway, the high thermal power released from one cell can spread to the adjacent cells, making entire modules unstable.
- Stability of cathode materials in contact with electrolyte is better for phosphate cathodes than oxide cathodes but phosphate-based batteries deliver lower potential. Thermal runaway can be suppressed using inhibitors (ref. 22).
- With LIB demand increasing exponentially every year, the supply of raw materials and incremental costs are the main concerns. Lithium extraction has the potential for geopolitical risks because the world's known resources of easily extractable lithium are largely concentrated in three South American countries: Chile, Bolivia, and Argentina (ref. 23), but the limited availability of cobalt resources remain the biggest concern.
- The self-discharge rate and all the parasitic losses in the system become a significant source of losses at residence times beyond a few days, hence Li-Ion batteries are not advisable for long-term storage.

Environment

Some LIB contain toxic cobalt and nickel oxides as cathode materials and thus need to be meticulously recycled. At present, the market price of component materials like lithium/cobalt is still not high enough for making it economically beneficial. Unlike portable electronics, large installations help enforce recycling regulations.

Lithium resource depletion from fast adoption of LIB in electric vehicles and utility scale storage is a concern (ref. 24). US-EPA reported that across the battery chemistries, the global warming potential impacts attributable to the LIB production is substantial (including energy used during mining): the literature points at a climate impact ranging from 39 kg $CO2_{eq}$/kWh to 196 kg $CO2_{eq}$/kWh (ref. 46).

Research and development

LIB have been well-known for decades, but their use as utility-scale storage has gained momentum only in recent years. LIB moved from the pioneer phase (category 2) to the commercial phase with a significant development potential (category 3). Therefore, there is still a significantly potential for R&D.

Due to the economic and technological impact, a wide range of government and industry-sponsored research is taking place across the world towards the improvement of LIB at material and system level.
Higher energy density is achievable by discovering new cathode with higher electrochemical potential and anode/cathode materials, which can build in more lithium per unit volume/weight.

Higher electrochemical potential for cathode materials also need to be matched with the electrochemical stability of the electrolyte used. Thus, research in new electrolyte systems is also needed. Electrolytes with better chemical stability also lead to lower chances of thermal runaway. Improved power capacity is obtained if lithium-ion movement is faster inside the electrode and the electrolyte materials. In short, cathodes with high electrochemical potential, anodes with low electrochemical potential, cathode/anodes with high lithium capacity, electron/lithium transport, electrolytes with large electrochemical stability window and fast lithium transport are the desirable directions in LIB research.

A nickel-phosphate-based cathode can operate at 5.5 V (compared to 3.7 V of cobalt oxide cathodes), but a complementary electrolyte is not available yet (ref. 25). On the anode side, silicon-based anodes can improve upon carbon-based anodes. Stability for long-term operations has however remained an issue (ref. 26). On the electrolyte side, ionic liquids are being researched for safer high-potential operations (ref. 27).

In the future, Lithium-Air and Lithium-Sulphur batteries could reach commercialization, but challenges related to humidity, unwanted chemical reactions (production and leaking of polysulphide ions into the electrolyte in the case of Li-S batteries).

Another promising branch of research is linked to Lithium Solid-State batteries (SSBs). SSBs use a solid electrolyte instead of a liquid/gel electrolyte as in today's Li-ion batteries: this would strongly reduce flammability risks and increase the energy density of a battery pack, besides being very stable (ref. 44). The main disadvantages connected to SSBs are the high cost, poor ionic conductivity of the electrolyte, incompatibility between electrolyte and electrodes and the fast growth of lithium dendrites. This eventually leads to a poor cycle performance and a rapid capacity degradation (ref. 45).

Investment cost estimation

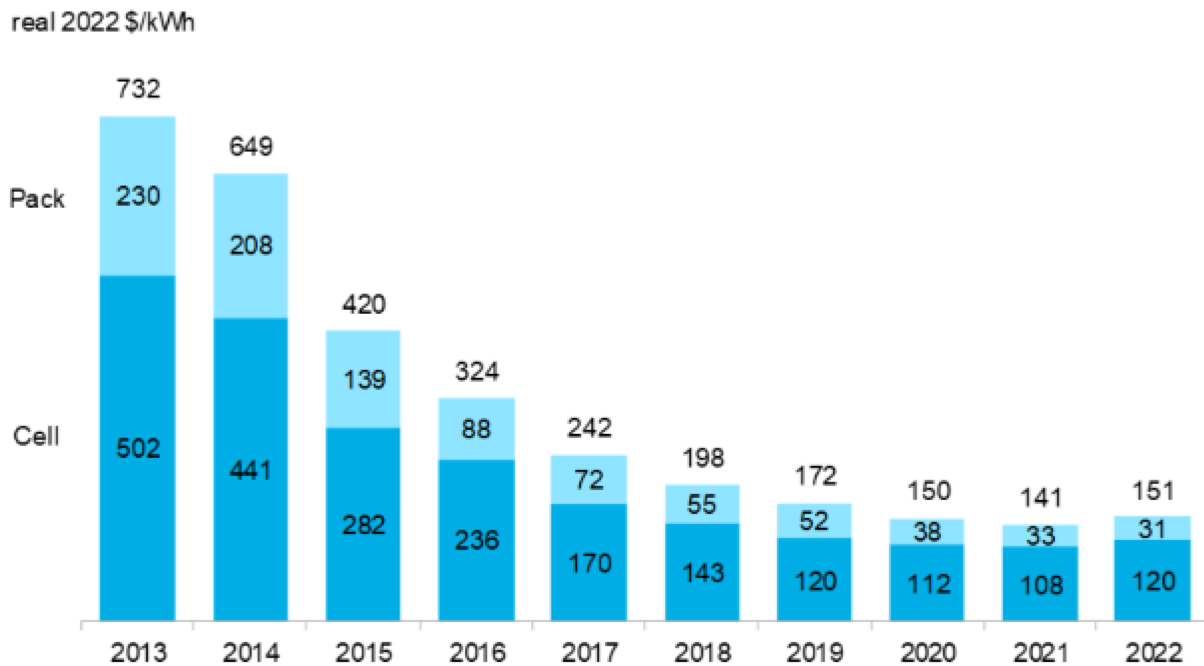
LIB installations for utility operation from major companies like Samsung SDI/TESLA are modular and scalable: costs can be assumed to increase linearly with the storage size. Modular systems that have been used by TESLA to create 80 MWh storage system within 3 months (ref. 29). Data for the Samsung SDI model is here the main reference for technical parameters; other manufacturers are considered to tune and compare the data.

Due to lack of specific daily discharge loss data, generally accepted information obtained from published journal articles and review papers is used as a standard (ref. 8). Unforeseen outages are very rare and can be considered not to occur, provided that good management is performed. Samsung SDI also suggests operation between C/2 to 3C rate (i.e., equivalent to a discharge time ranging from 2h to 0.33h). A 10C-rate, long-lifetime battery (ref. 30) is under development and 20C-60C-rate batteries are being experimented (ref. 31).

Commercial units have nowadays a lifetime of about 10000 cycles (ref. 42). More stable electrode materials (e.g. polyanion cathode and titanate anode) and a better system management are set to boost the asset's lifetime, which is projected to reach 30 years in 2050.

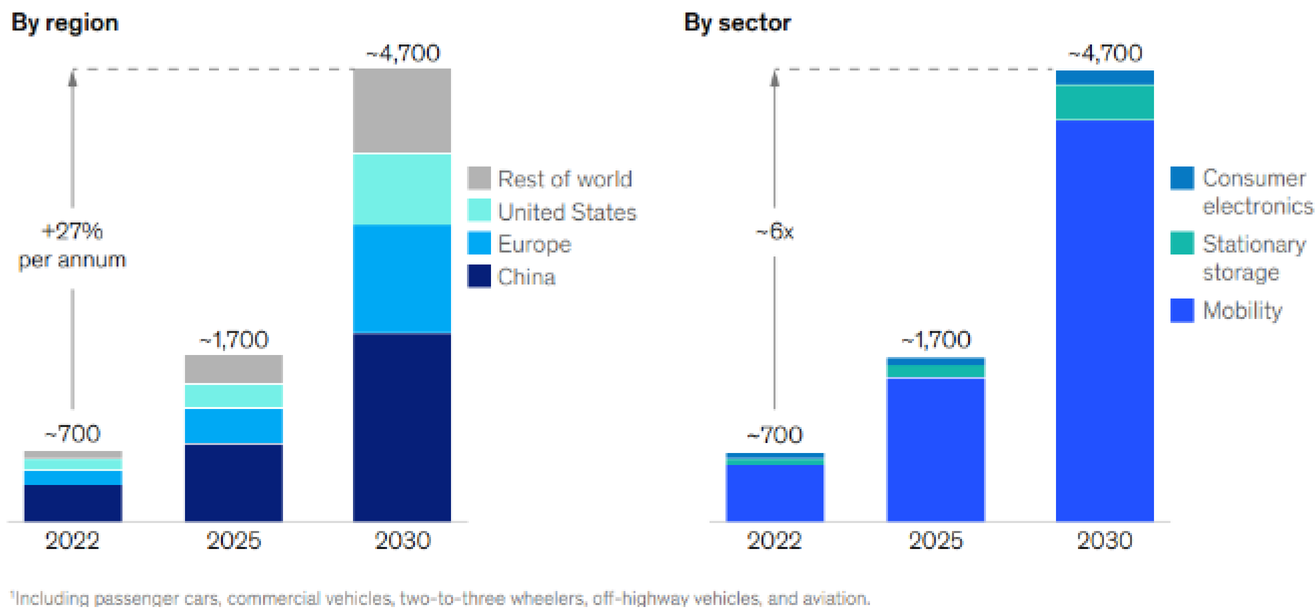
Modular manufacturing and automated installation capabilities can drastically cut down on system setup time to few weeks from current ~3 months, as demonstrated by TESLA.

Round-trip efficiency is already rather high and the improvement in system performance will therefore be minimal in the future. Internal losses depend on advancements in battery chemistry and R&D in cell materials; materials will also affect the performance of power electronics, whose efficiency could improve by some % in the next years due to better-engineered solid-state converters.



Li-ion battery pack and cell cost (volume-weighted average from transport and stationary storage)
Source BloombergNEF (2022)

The LIB market has been interesting for the last few years. As shown in the figure above, after years of dramatic cost declines, prices have stagnated as cost of materials have increased during the COVID-19 pandemic and Russian invasion of Ukraine. However, this does not paint the full picture, as demand has also taken off.



Projected global Li-ion battery demand (GWh). Source: McKinsey Battery Insights Demand Model

In 2020, li-ion cell demand was roughly 250 GWh annually, and already in 2022 it was roughly 700 GWh annually. It is expected that this trend (increase in demand) will continue. If this is true, it could be before 2025, the world will be producing more than a TWh of li-ion batteries per year. Furthermore, if material prices fall back down to what they were in the previous decade, because the cost declines primary are driven by upscaling and development of production of factories, research and development, thus, development which we are used to seen could come back in a big way.

All this is to say that while there has been price stagnation in recent years, it is not an indication that we have reached full maturity of this technology. Rather, material costs have increased greatly while demand has continued to increase at an exponential rate. This means if material costs fall back down to levels seen in the past decade, which could happen as the current material markets should incentivise more investment in extraction, then the cost of Li-ion and similar battery technology should once again fall in price.

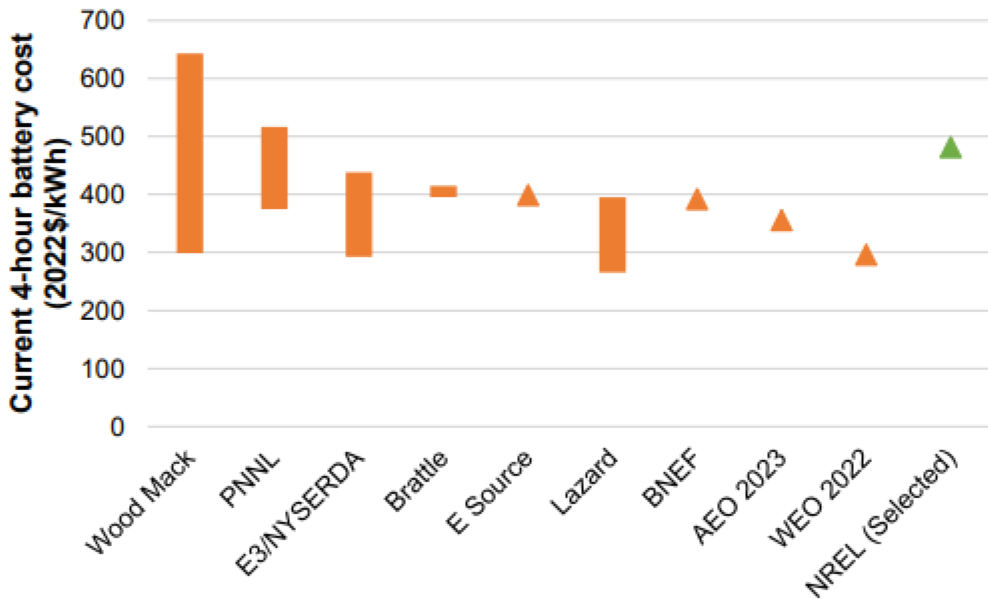
The price of a small-size battery storage such as TESLA's *Powerwall* (13.5kWh/7kW unit, 0.5 C-rate) can be assumed to be around 500 USD/kWh in 2020, which excludes hardware and installation costs. Figures are lower for bigger storage units.

Lazard's Levelised Cost of Storage 2023 report estimates O&M costs to lie in a wide range (1.3-7.7 USD/kWh). These include both fixed and variable O&M. When costs are calculated for the asset's lifetime, O&M can account for between 1/4 and 1/3 of the Levelised Cost of Storage (ref. 34). Although module costs will decrease, counterbalancing effects from more expensive engineering and further automation would keep installation costs and O&M costs at a similar level or even slightly higher.

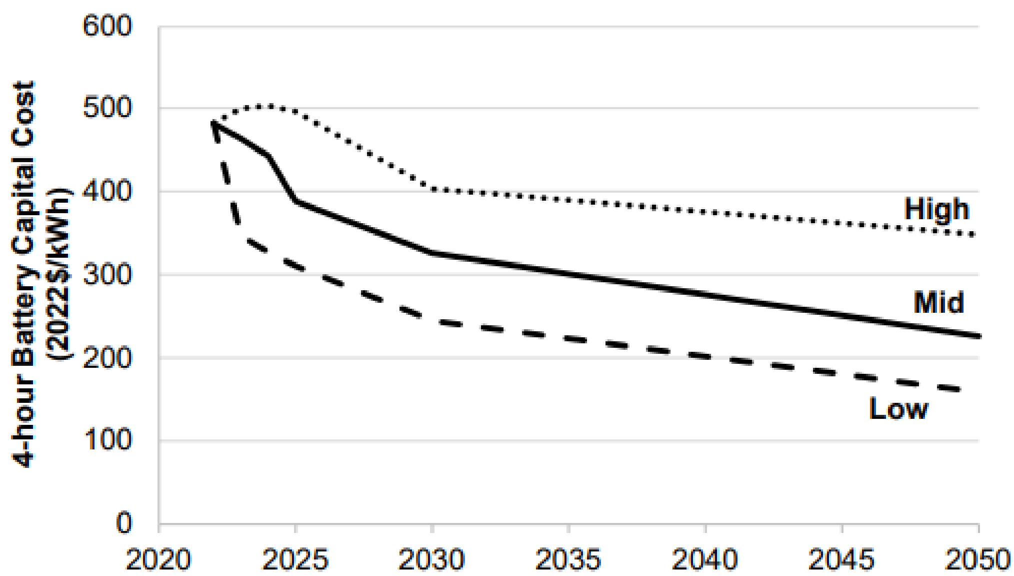
Similar to the semiconductor industry, improvements in LIB have been exponential (ref. 35), with price reductions of ~15%/year. Demand from EV and electronic industry have contributed to the accelerated development of the manufacturing industry and of the supply chain. Further improvements came from the R&D knowledge in high-performance materials reaching commercial status. It is assumed that energy density will improve in 2030 by ~30-50% due to R&D efforts put into the battery materials.

Investment cost estimate, overview

Data presented in the data sheet are from specific cases and publicly available sources. Better-negotiated prices are most possibly accessible to project managers. Uncertainty in future development of technology and commercialization affect the accuracy of the suggested numbers for LIB energy storage systems.



Recent battery storage costs from various recent studies for 4-hour system. (ref 53)



Battery cost projections for 4-hour lithium-ion systems. (ref 53)

Uncertainty in future data

Development in LIB has been rapid in recent times and upgrades in manufacturing capacity and technologies have been astounding. This is aided by the explosion of the requirements in the area of EV and portable electronics. Large R&D efforts are accelerating the progress, unlike any other storage technologies. For example, development in 6V capable electrolytes, vanadate cathodes and silicon-based anodes can increase the electrochemical potential by 70% and Li-capacity by 3 times – leading to 5-fold increases in the energy density, but these technologies are many years from commercialization. In addition, a polymer gel electrolyte-based battery has been developed that has a cycle life of 200,000 at 96% efficiency (ref. 36). Commercialization of such technology can make LIB systems last for centuries.

Examples of current projects
According to S&P Global (Ref. 48), in March 2023 there were 2.8 TWh of lithium-ion battery capacity installed worldwide. Many energy storage systems provide system support by participating in frequency regulation services. An example of a large such installation is the Hornsdale battery in Australia. Technology providers include TESLA, A123 systems, LG Chem, BYD, Toshiba, Samsung SDI.

- The largest battery system in the world currently is the Moss Landing Energy Storage Facility. The 750MW/3000MWh system is located in Monetery County, California, USA, and is own and operated by Vistra Energy. Ref (49)
- The 409MW/900MWh Manatee Energy Storage Center Manatee Battery Energy Storage Center, located in Florida and owned and operated by Florida Power & Light (FPL), is the largest battery system to only be loaded by solar (Ref. 50).
- The Victorian Big Battery, located near Geelong, Australia, coming in at 300MW/450MWh, is the largest battery in Australia (Ref. 51)
- Hornsdale TESLA battery in Australia. 129MWh/100MW (+50MW/64.5MWh expansion in 2020). The facility provides mainly system support in the frequency regulation market, but also bulk energy services.
- AES/Samsung SDI/Parker Hannifin. 30 MW and 120 MWh (bulk energy service). SDG&E Escondido, San Diego, USA. From 2017.
- Samsung SDI/GE. 30 MW and 20 MWh (black start and frequency regulation). Imperial Irrigation District, El Centro, California, USA. From 2016.

Toshiba. 40 MW and 40 MWh (bulk energy service for RE). Minamisoma, Fukushima Prefecture, Japan. From 2016.

The 40 MW and 40 MWh energy storage system in Fukushima, Japan.

PLS Hybrid Nusa Penida (ref 47)

This PLTS, with a capacity of 3.5-Megawatt peak (MWp), has the potential to reduce CO2 emissions by 4.19 thousand tons per year for the island of Bali. The PLTS was erected on 4.5 hectares of land. This PLTS is a hybrid system generator that includes a diesel power plant (PLTD), PLTS, and a Battery Energy Storage System (BESS) with a capacity of 1.84-megawatt hour (MWh). Udayana further stated that other EBT generators, notably PLTS in eastern and western Bali, each with a capacity of 25 megawatts (MW), and the Titab Minihydro Power Plant (PLTMH) with a capacity of 1.3 MW, are planned for 2023.

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Data sheets

The following pages content the data sheets of the technology. All costs are stated in U.S. dollars (USD), price year 2022. The *uncertainty* it related to the specific parameters and cannot be read vertically – meaning a product with lower efficiency do not have the lower price or vice versa.

Technology

Technology	Batteries - Lithium-ion (utility-scale)								
	2023	2030	2050	Uncertainty (2023)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Energy storage capacity for one unit (MWh)	4	4	4	4	4	4	4	A, B	
Discharge time (hours)	4	4	4	4	4	4	4	A, B	
Round-trip efficiency (%) AC	90	92	92					C	1
Round-trip efficiency (%) DC	95	96	96					C	1
Self-discharge rate (%/day)	0.10	0.10	0.10						2
Forced outage (%)	0.38	0.35	0.25					M	
Planned outage (weeks per year)	0.20	0.10	0.10					L	
Technical lifetime (cycles)	7,500	10,000	15,000					M	3
Technical lifetime (years)	15	20	25					D	3
Construction time (years)	0.20	0.20	0.20						
Energy density (Wh/kg)	150	200	300						
Ramping configurations									
Response time from idle to full-rated discharge (ms)	50	50	50						4
Response time from full-rated charge to discharge (sec)	<0.08	<0.08	<0.08	<0.08	<0.08	<0.08	<0.08	O	7
Financial data									
Total investment (MUSD/MWh)	0.47	0.33	0.23	0.35	0.54	0.17	0.45	G	1,5,6,10
- energy component (MUSD/MWh)	0.35	0.23	0.15	0.26	0.38	0.12	0.26		1,5,6,9,11
- power component (MUSD/MW)	0.33	0.29	0.25	0.24	0.35	0.10	0.27	H	1,5,6,9,11
- other project costs (MUSD/MWh)	0.04	0.03	0.02	0.03	0.07	0.02	0.13	N	5,6,9
Fixed O&M (USD/MW/year)	15,000	10,500	7,350	5,000	50,000	2,500	15,000	O	6,9,10
Variable O&M (USD/MWh)	2.00	1.80	1.60	2.00	2.60	1.60	2.20	I	7,10
Technology specific data									
Energy storage expansion cost (MUSD/MWh)	0.28	0.18	0.14					F	
Output capacity expansion cost (MUSD/MW)	0.26	0.17	0.13						
Total investment (MUSD/MW)	1.33	0.95	0.64						

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Notes:

A A 4-hour battery has been picked as a reference, as there is more data availbe for this power-to-energy ratio in the references listed.

B Power and energy output can be scaled linearly by utilizing many modules (up to 250 MW has been demonstrated, https://www.pv-magazine-australia.com/2023/08/10/battery-capacity-overtakes-pumped-hydro-in-nem/). Output capacity expansion can be done reprogramming the management unit without any new battery module. For Utility batteries the ratio between energy storage and capacity is in general between 1 and 10 (C-rate between 1/10 and 1) only rarly the ration will be below 1.

C The gradual change towards lower C-rates following the transition from frequency regulation to renewable integration promotes lower C-rates. Therefore the average DC roundtrip efficiency is expected to increase slightly. The RT eff. vs. C-rate is exemplified in Figure 7 [3,51]. The AC roundtrip efficiency includes losses in the power electronics and is 2-4% lower than the DC roundtrip efficiency. The total roundtrip efficiency further includes standby losses making the total roundtrip efficiency typically ranging between 80% and 90%. [21,22]

D Samsung SDI 2016 whitepaper on ESS solutions provide 15 year lifetime for current modules operating at C =1/2 to C=3. Steady improvement in battery lifetime due to better materials and battery management expected. Number of cycles can be a more meaningful lifetime indicator.

E The discharge time is the amount of hours the battery can discharge at rated output capacity. It equals the Energy/Power ratio corrected for the discharge efficiency.

F Since multi-MWh LIB systems are scalar, the energy and outputr capacity expansion costs are here estimated to be equal to the energy and output capacity components plus the “other costs”

G Power conversion cost is strongly dependent on scalability and application.

H The gradual change towards lower C-rates following the transition from frequency regulation to renewable integration promotes lower C-rates. Therefore the average DC roundtrip efficiency is expected to increase slightly. The RT eff. vs. C-rate is exemplified in Figure 7 [3,51]. The AC roundtrip efficiency includes losses in the power electronics and is 2-4% lower than the DC roundtrip efficiency. The total roundtrip efficiency further includes standby losses making the total roundtrip efficiency typically ranging between 80% and 90%

I Cost per MWh of energy discharged from the battery

L It is expected not to have any outage during lifetime of the grid-connected LIB. Only a few days during the e.g. 15 years life time is needed for service and exchanging fans and blowers for thermal management system and power conversion system. Forced outage is expected to drop with increasing robustness following the learning rate and cumulated production. Planned outage is expected to decrease after 2020 due to increased automation.

M Cycle life specified as the number of cycles at 1C/1C to 80% state-of-health. Samsung SDI 2016 whitepaper on ESS solutions provide 15 year lifetime for current modules operating at C/2 to 3C [14]. Steady improvement in battery lifetime due to better materials and battery management is expected. Kokam ESS solutions are also rated at more than 8000-20000 cycles (80-90% DOD) based on chemistry [3]. Thus for daily full charge-discharge cycles, the batteries are designed to last for 15-50 years if supporting units are well functioning. Lifetimes are given for both graphite and LTO anode based commercial batteries from Kokam.

N Other costs include construction costs and entrepreneur work. These costs heavily dependent on location, substrate and site access. Power cables to the site and entrepreneur work for installation of the containers are included in other costs. Therefore other costs are assumed to – roughly – correlate with the system size. Automation is expected to decrease other costs from 2030 and onwards.

O The response time is obtained from simulated response time experiments with hardware in the loop.

Examples for calculation of CAPEX using datasheet:

1. Frequency regulation in 2023: 4C-rate, 2 MWh BESS system, 20 years operation time.

Cost items:
2 MWh “energy component”, year 2023
2 MWh “other project costs”, year 2023
4C = 0.25-hour discharge time ⇒ 8 MW “power component”, year 2020

CAPEX calculation: 2 * (0.152 M$ + 0.115 M$) + 8 * 0.311 M$ = 3.022 M$

2. Energy integration in 2030: ¼C-rate, 16 MWh BESS system, 25 years operation time.

Cost items:
16 MWh “energy component”, year 2030
16 MWh “other project costs”, year 2030
¼C= 4-hour discharge time ⇒ 4 MW “power component”, year 2030

CAPEX calculation: 16 * (0.062 M$ + 0.11 M$) + 4 * 0.184 M$ = 3.488 M$

22. Hydrogen Fuel Cells

Brief technology description

Simply put, hydrogen fuel cells convert hydrogen into electricity, with the only by-product being water vapor and heat. They operate somewhat like batteries, as they have a negative electrode (anode) and a positive cathode (a cathode) which are separated by an electrolyte. They are different to batteries in that they need a fuel as a catalyst in order to produce electricity, in this case hydrogen. Hydrogen is fed to the cathode, and oxygen is fed to the anode. Separated by an electrolyte, the hydrogen molecules get separated into protons and electrons which take separate paths to the cathode. The electrons are sent through an external circuit, thus creating a flow of electricity. (Ref. 1)

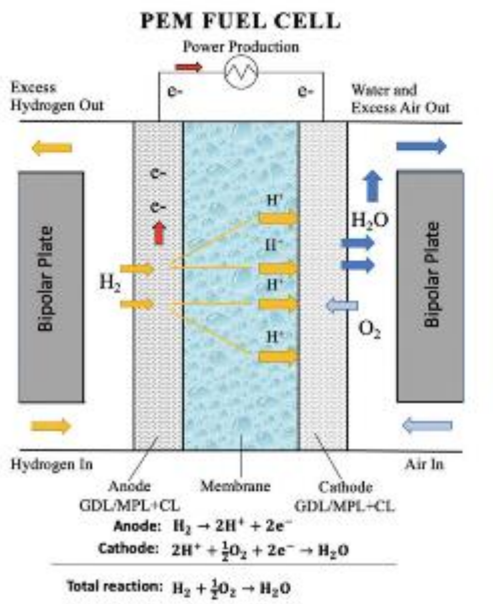


Diagram of how PEMFCs operate. (Ref 2)

The two most common types of fuel cells are Polymer exchange membrane fuel cells (PEMFC) and solid oxide fuel cells (SOFC). PEMFCs have been used in hydrogen fuel cell cars as they have an energy density and low operating temperature relative to other fuel cell technologies. Due to their use in transportation, PEMFCs have received a lot more research and development effort comparted to other fuel cell technologies. SOFCs on the other hand have low energy density and higher operating temperatures, and a higher electricity efficiency. This high temperature operation makes them unusable for transport applications, however for stationary electricity production, this is not a problem.

Input

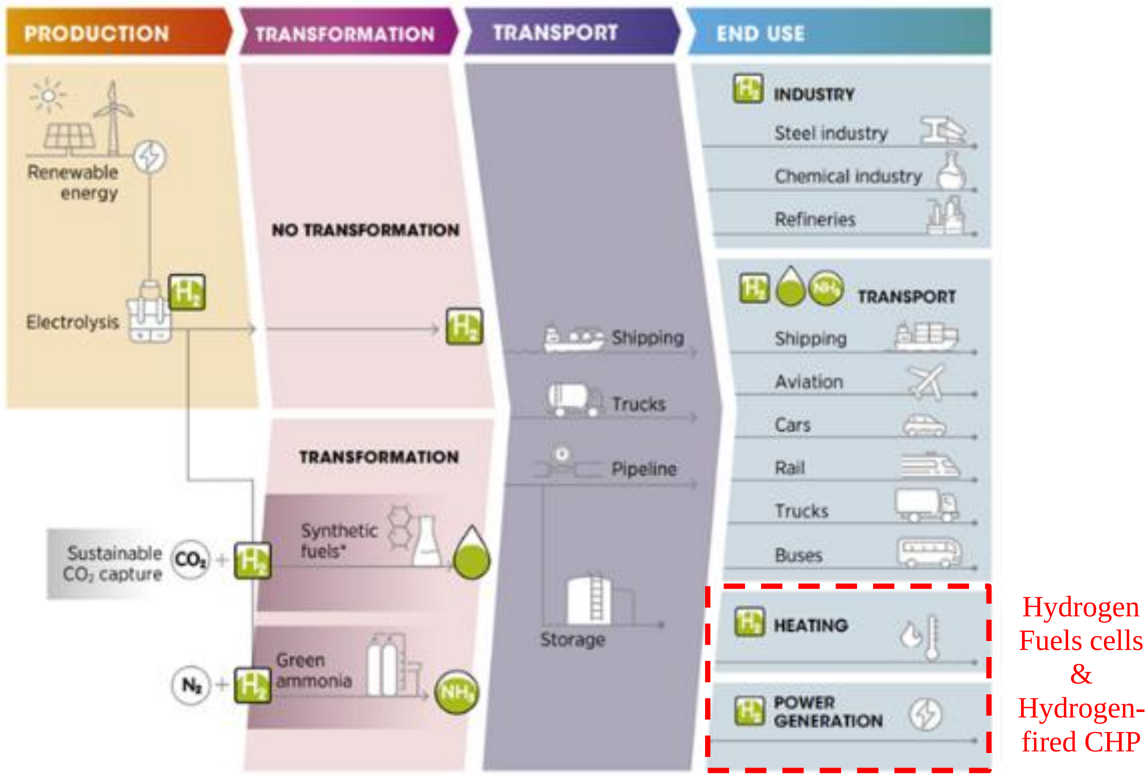
Hydrogen

Output

Electricity, Heat, Water

A growing number of experts have the expectation that hydrogen will play a large role in decarbonized energy systems. The reason for this is that it can be used to help decarbonize difficult-to-abate sectors of the world's economy, such as the shipping, aviation, and steel industries. However, this is only the case if the hydrogen is produced by renewable energy (green hydrogen) via electrolysis or nuclear energy (pink hydrogen) via electrolysis, as otherwise the hydrogen would not be considered emission free. If hydrogen is present in the system, then there is a possibility to convert it back into electricity when needed. This makes hydrogen a potential option for long-term storage as it is possible to store hydrogen for long periods of time without losses (unlike batteries, which lose charge over time).

If there is a desire to convert that hydrogen back into electricity (and possibly heat), fuel cells could be used. Fuel cells convert hydrogen and oxygen into electricity via an electrochemical process that also produces excess heat and water. We could also simply burn hydrogen in hydrogen-ready CHP plants, but there are NOx emissions that come from this process. Currently, fuel cells convert hydrogen into electricity much more efficienctly than simply burning hydrogen in a converted gas power plant. However, if the hydrogen is burned in a combined cycle CHP plant, the efficiency of burning hydrogen matches that of current fuel cell technology.



Overview of hydrogen's potential role in the energy system. Red box and text have been added here to show which part of the hydrogen system is being discussed in this section. Source of original figure: IRENA

Investment cost estimate

Currently, the cost for stationary hydrogen fuel cells is high, and only 90 MW of stationary hydrogen fuel cells in is operation in the world today, primarily for backup power for telecom in the United States. Pacific Northwest National Laboratory (PNNL) found that in 2020, the upfront cost of stationary fuel cells was between $1188/MW and $1452/MW (Ref. 9).

In order for fuel cells to become competitive, they will need to drastically fall in price. Governments around the world will have to step in and create incentives for companies to make the necessary investments to build stationary fuel cells at scale. According to Hydrogen Council (Ref. 4), 33 billion USD of government incentives will be needed for fuel cells to fall enough in price to become competitive.

Current issues

Unfortunately for fuel cells, many of the world's largest CHP companies already offer hydrogen ready CHP plants, which can switch fuel from running 100% natural gas to 100% hydrogen, as well as mixes of the two. For this reason, while there are only 90 MW of stationary hydrogen fuel cells in use today (the other 2.4 GW use natural gas), there are 2.5 GW of planned CHP plants which are capable of running 100% on hydrogen by 2030 (Ref. 8). In addition, most CCGT manufacturers already offer or are developing 100% hydrogen offerings. If the assumption is that hydrogen-to-electricity technologies will only be used for long-term storage and or peaker plants, then it is understandable why companies have been hesitant to invest in large scale stationary fuel cell production as hydrogen-to-electricity technology will only be needed for a small portion of the year. However, if hydrogen were expected to be needed for electricity production for many hours of the year, then FCs could be needed for situations where combined cycle hydrogen CHP is not an option.

Fuel cells could also have a role in certain transport applications, where refuelling speed needs to be higher, such as ferries, busses, farming equipment, and forklifts.

Examples of current projects

50 MW byproduct-hydrogen-fuel-cell power plant located in Seosan, South Korea. (Ref 10)

Half of the world's stationary hydrogen fuel cell capacity is located at one plant in Seosan, South Korea. This 50MW plant was built in an industrial complex which had a lot of excess hydrogen (also called byproduct-hydrogen) from chemical manufacturing, making this plant economical as the hydrogen is very cheap to acquire.

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Data sheets

No data sheet is developed for fuel cells.

LAMPIRAN: METODOLOGI (BAHASA)

Pengantar metodologi

Teknologi yang dijelaskan dalam katalog ini mencakup teknologi yang telah matang dan diharapkan akan meningkat secara signifikan dalam beberapa dekade mendatang, baik dari sisi kinerja maupun biaya. Hal ini menunjukkan bahwa harga dan kinerja dari beberapa teknologi mungkin dapat diestimasi dengan tingkat kepastian yang agak tinggi, sedangkan untuk teknologi lainnya, biaya dan kinerja saat ini maupun di masa depan dikaitkan dengan tingkat ketidakpastian yang tinggi. Semua teknologi telah dikelompokkan dalam satu dari empat kategori pengembangan teknologi (dijelaskan dalam bagian tentang Penelitian dan Pengembangan) yang menunjukkan tingkat kemajuan teknologinya, perspektif pengembangannya masa depan, dan ketidakpastiannya terkait proyeksi data biaya dan kinerja.

Batasan untuk data biaya dan kinerja adalah aset pembangkitan ditambah infrastruktur yang diperlukan untuk memasok energi ke jaringan utama. Untuk listrik, batasan ini adalah gardu terdekat ke jaringan transmisi. Hal ini menunjukkan bahwa satu Mega Watt listrik merepresentasikan besaran listrik bersih yang dipasok, yaitu jumlah kotor pembangkitan dikurangi jumlah listrik tambahan yang digunakan di pembangkit. Oleh karena itu, efisiensi pembangkit juga merupakan efisiensi neto.

Kecuali dinyatakan lain, teknologi termal dalam katalog diasumsikan dirancang beroperasi kira-kira 6000 jam pembangkitan dengan beban penuh setiap tahunnya (faktor kapasitas 70%). Beberapa pengecualian adalah fasilitas pembangkit listrik tenaga sampah padat perkotaan dan panas bumi, yang dirancang untuk beroperasi terus menerus, yaitu sekitar 8000 jam beban penuh setiap tahun (faktor kapasitas 90%).

Masing-masing teknologi dijelaskan dalam lembar teknologi terpisah, mengikuti format yang dijelaskan di bawah ini.

Deskripsi Kualitatif

Deskripsi kualitatif menggambarkan karakteristik kunci dari teknologi sesingkat mungkin. Paragraf berikut disertakan jika ditemukan hal yang relevan untuk teknologi tersebut.

Deskripsi Teknologi
Deskripsi singkat tentang bagaimana teknologi bekerja dan tujuan penggunaannya.

Input
Bahan baku utama, terutama bahan bakar, dibutuhkan oleh teknologi tersebut.

Output
Output dari teknologi dalam katalog ini adalah listrik. Output lain seperti panas proses bisa disebutkan disini.

Kapasitas Tipikal
Kapasitas yang dicantumkan adalah untuk mesin tunggal (sebagai contoh, turbin angin tunggal atau turbin gas tunggal), dan juga untuk pembangkit listrik total yang terdiri dari banyak mesin seperti ladang turbin angin. Kapasitas total pembangkit listrik seharusnya merupakan kapasitas tipikal di Indonesia.

Konfigurasi Perubahan Kapasitas Cepat (Ramping) dan Layanan Sistem Pembangkit Lainnya
Deskripsi singkat tentang konfigurasi ramping untuk teknologi pembangkit listrik, yaitu bagaimana karakteristik beban parsial, seberapa cepat pembangkit mulai nyala/hidup (start up), dan seberapa cepat pembangkit bereaksi terhadap perubahan permintaan (ramping)

Kelebihan dan Kekurangan
Keuntungan dan kerugian spesifik relatif terhadap teknologi yang setara. Kelebihan umum diabaikan; sebagai contoh, teknologi energi baru dan terbarukan mengurangi risiko iklim dan meningkatkan keamanan pasokan.

Lingkungan
Karakteristik lingkungan tertentu yang disebutkan, misal emisi khusus atau jejak ekologi utama.

Ketenagakerjaan
Deskripsi tenaga kerja yang diperlukan teknologi dalam proses manufaktur dan instalasi serta selama pengoperasian. Hal ini akan dilakukan baik dengan contoh maupun dengan mencantumkan persyaratan didalam peraturan perundang-undangan untuk kandungan dalam negeri (Peraturan Menteri Perindustrian Nomor 54/M-IND/PER/3/2012 dan Nomor 05/M-IND/PER/2/2017). Semua proyek yang dimiliki atau didanai oleh pemerintah atau perusahaan milik negara diwajibkan untuk mengikuti peraturan ini.

Penelitian dan Pengembangan
Bagian ini harus mencantumkan tantangan yang paling penting dilihat dari perspektif penelitian dan pengembangan. Khususnya perspektif penelitian dan pengembangan di Indonesia yang dipilih jika relevan.

Bagian ini juga menggambarkan seberapa matang teknologi tersebut.

Tahun pertama proyeksi adalah 2023 (tahun dasar). Didalam katalog ini, diharapkan bahwa penurunan biaya dan peningkatan kinerja bisa diwujudkan di masa yang akan datang.

Bagian ini memberikan asumsi-asumsi yang mendasari perbaikan yang diasumsikan dalam lembar data untuk tahun 2030 dan 2050.

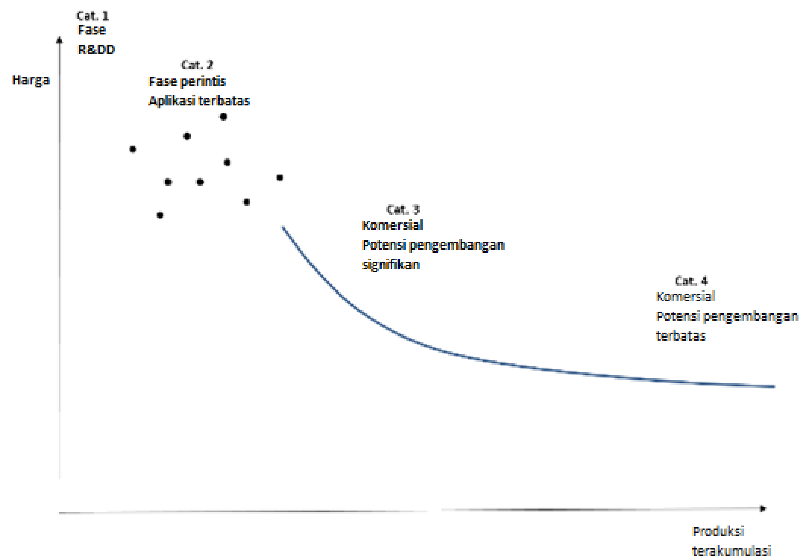
Potensi peningkatan teknologi dikaitkan dengan tingkat kematangan teknologi. Oleh karena itu, bagian ini juga mencakup deskripsi kemajuan teknologi dan komersialisasi teknologi tersebut. Teknologi dikategorikan dalam salah satu dari empat tingkat kematangan teknologi berikut.

<u>Kategori 1.</u> Teknologi yang masih dalam tahap penelitian dan pengembangan. Ketidakpastian terkait harga dan kinerja hari ini dan masa yang akan datang, sangat signifikan.

<u>Kategori 2.</u> Teknologi dalam fase perintis. Melalui fasilitas *demo-plants* atau *semi-commercial plants*, sudah terbukti bahwa teknologi tersebut berhasil. Karena keterbatasan aplikasi, harga dan kinerja masih dikaitkan dengan ketidakpastian yang tinggi, karena pengembangan dan penyesuaian masih diperlukan. (misal gasifikasi biomassa).

<u>Kategori 3.</u> Teknologi komersial dengan tingkat penyebaran moderat. Harga dan kinerja dari teknologi sudah cukup dikenal saat ini. Teknologi ini dianggap memiliki potensi pengembangan yang signifikan dan oleh karena itu terdapat tingkat ketidakpastian yang cukup besar terkait dengan harga dan kinerja di masa depan (misal turbin angin lepas pantai)

Kategori 4. Teknologi komersial, dengan tingkat penyebaran yang besar. Harga dan kinerja teknologi sudah sangat diketahui saat ini, dan biasanya peningkatan hanya akan terjadi secara bertahap. Oleh karena itu, harga dan kinerja di masa yang akan datang bisa diproyeksikan dengan tingkat kepastian cukup tinggi (misal pembangkit batubara, turbin gas).



Tahap pengembangan teknologi. Korelasi antara akumulasi volume produksi (MW) dan harga.

Estimasi biaya investasi
Pada bagian ini, proyeksi biaya investasi dari berbagai sumber dibandingkan, jika relevan. Jika tersedia, proyek lokal disertakan bersama dengan proyeksi internasional dari sumber terakreditasi (misalnya IRENA). Di atas tabel, nilai biaya yang disarankan diperjelas. Nilai biaya investasi lokal dilaporkan langsung jika tersedia, jika tidak, angka tersebut berasal dari hasil PPA, lelang dan / atau mekanisme pendukung.

Proyeksi biaya berdasarkan pendekatan kurva pembelajaran ditambahkan di bagian bawah tabel untuk menunjukkan tren biaya yang diperoleh dari penerapan pendekatan kurva pembelajaran. Teknologi tunggal diberi biaya normalisasi 100% pada tahun 2020 (tahun dasar); nilai yang lebih kecil dari 100% untuk tahun 2030 dan 2050 mewakili pembelajaran teknologi, sehingga pengurangan biaya relatif terhadap tahun dasar. Suatu contoh tabel diberikan di bawah ini.

Biaya Investasi [MUSD$_{2019}$/MW]		**2020**	**2023**	**2030**	**2050**
Katalog	Katalog baru (2023)				
	Katalog lama (2020)				
Data Indonesia	Data lokal I				
	Data lokal II				
Data Internasional	Katalog teknologi Denmark				
	IRENA				
	IEA WEO 23				
Proyeksi	Kurva pembelajaran – tren biaya [%]				

Contoh proyek saat ini
Inovasi teknologi terbaru dalam skala operasi komersial penuh harus disebutkan dalam katalog ini, sebaiknya diberikan referensi dan tautan untuk informasi lebih lanjut. Ini belum tentu merupakan teknologi terbaik yang tersedia atau *Best Available Technology* (BAT), namun lebih merupakan suatu indikasi standar yang saat ini sedang dikerjakan.

Referensi
Semua deskripsi harus mempunyai referensi, yang tercantum dan ditegaskan dalam deskripsi kualitatif.

Deskripsi Kuantitatif

Berikut adalah lembar data tipikal, berisi semua parameter yang digunakan untuk menggambarkan teknologi tertentu. Lembar data terdiri dari bagian umum, yang formatnya sama untuk kelompok yang mempunyai teknologi serupa (pembangkit listrik termal, pembangkit listrik non termal dan teknologi pembangkit panas) dan bagian teknologi spesifik, berisi informasi yang hanya relevan untuk teknologi spesifik tersebut. Bagian teknologi umum dibuat untuk memudahkan perbandingan antar teknologi.

Setiap sel di lembar data hanya boleh berisi satu nilai, yang merupakan estimasi tengah untuk teknologi tertentu, yaitu tidak ada indikasi kisaran. Ketidakpastian yang terkait dengan nilai harus dinyatakan dalam kolom terpisah yang disebut ketidakpastian. Untuk menjaga agar lembar data tetap sederhana, tingkat ketidakpastian hanya ditentukan untuk tahun 2023 dan 2050 dan untuk parameter tekno ekonomi terpilih (data keuangan, data kinerja utama). Ketidakpastian tersebut terkait dengan teknologi 'standar pasar'. Dengan kata lain, interval ketidakpastian tidak mewakili rangkaian produk (misalnya produk dengan efisiensi lebih rendah dengan harga lebih rendah atau sebaliknya). Untuk teknologi tertentu, katalog ini mencakup rangkaian produk, contohnya untuk pembangkit batubara, di mana pembangkit sub-kritis, super kritis dan ultra-super kritis terwakili.

Hampir semua nilai dalam lembar data diberi nomor referensi di kolom paling kanan dan mengacu pada sumber yang disebutkan di bawah tabel.

Sebelum menggunakan data, perlu memperhatikan informasi penting yang dapat ditemukan di catatan di bawah tabel.

Bagian umum dari lembar data untuk pembangkit listrik termal, pembangkit listrik non termal dan teknologi pembangkitan panas disajikan di bawah ini:

Teknologi	Nama Teknologi								
	2023	2030	2050	Ketidakpastian (2023)		Ketidakpastian (2050)		Catatan	Ref
Data Energi/Teknis				Bawah	Atas	Bawah	Atas		
Kapasitas pembangkit untuk satu unit (MWe)									
Kapasitas pembangkit listrik total (MWe)									
Efisiensi listrik, neto (%), name plate									
Efisiensi listrik, neto (%), rata-rata tahunan									
Pemadaman paksa (%)									
Pemadaman terencana (minggu per tahun)									
Umur teknis pembangkit (tahun)									
Waktu konstruksi (tahun)									
Persyaratan lahan(1000 m^2/MWe)									
Data tambahan untuk pembangkit non termal									
Faktor kapasitas (%), teoritis									
Faktor kapasitas (%), termasuk pemadaman									
Konfigurasi ramping									
Ramping (% per menit)									
Beban minimum (% dari beban penuh)									
Waktu warm start-up time (jam)									
Waktu cold start-up time (jam)									
Lingjungan									
PM 2.5 (gram per Nm^3)									
SO_2 (derajat desulfurirasi, %)									
NO_X (g per GJ bahan bakar)									
CH_4 (g per GJ bahan bakar)									
N_2O (g per GJ bahan bakar)									
Data keuangan									
Investasi nominal ($/MWe)									
- bagian peralatan									
- bagian instalasi									
O&M tetap ($/Mwe/tahun)									
O&M variabel ($/MWh)									
Biaya start-up ($/Mwe/start-up)									
Data teknologi tertentu									

Referensi:

1

2

Catatan:

A

B

Data Energi/Teknis

Kapasitas Pembangkitan
Kapasitas dinyatakan baik untuk mesin tunggal, misal turbin angin atau mesin gas tunggal, maupun untuk pembangkit listrik total, misalnya ladang pembangkit tenaga angin atau pembangkit listrik berbahan bakar gas yang terdiri dari beberapa mesin gas. Jumlah unit dan ukuran pembangkit listrik total mewakili pembangkit listrik tipikal. Perhitungan faktor untuk mengubah skala data di katalog menjadi ukuran pembangkit lainnya selain yang telah disebutkan akan disajikan berikutnya di bagian metodologi ini.

Kapasitas diberikan sebagai kapasitas pembangkitan neto yang beroperasi secara kontinu. Artinya, kapasitas kotor (output dari generator) dikurangi konsumsi sendiri (beban sendiri) sama dengan kapasitas yang dikirim ke grid.

Satuan MW digunakan untuk kapasitas pembangkit listrik (kW untuk pembangkit kecil), sedangkan satuan MJ/s digunakan untuk konsumsi bahan bakar.

Hal ini menggambarkan kisaran kapasitas produk yang sesuai (MW), misalnya 200-1000 MW untuk pembangkit listrik tenaga batubara baru. Perlu ditekankan bahwa data dalam katalog didasarkan pada kapasitas tertentu, misalnya 600 MW untuk pembangkit listrik tenaga batubara. Bilamana penyimpangan dari kapasitas tipikal terjadi, efek dari skala ekonomi perlu dipertimbangkan (lihat bagian tentang biaya investasi).

Efisiensi Energi
Efisiensi untuk semua pembangkit termal dinyatakan dalam prosentase pada nilai kalori rendah (nilai panas rendah atau nilai panas bersih) pada kondisi Indonesia, dengan mempertimbangkan suhu udara rata-rata sekitar 28°C.

Efisiensi listrik pembangkit termal sama dengan pengiriman listrik total ke grid dibagi dengan konsumsi bahan bakar. Dua nilai efisiensi dicantumkan: efisiensi pada label seperti yang dinyatakan oleh pemasok dan efisiensi tahunan tipikal yang diharapkan.

Seringkali terjadi bahwa efisiensi listrik sedikit menurun selama masa pengoperasian pembangkit listrik termal. Degradasi ini tidak tercermin dalam data yang disebutkan. Aturan berdasarkan pengalaman, anda bisa mengurangi 2,5 - 3,5% selama masa pengoperasian (misalnya dari 40% menjadi 37%).

Pemadaman Paksa dan Terencana
Pemadaman paksa didefinisikan sebagai frekuensi jam pemadaman paksa terbobot dibagi dengan penjumlahan antara jumlah jam pemadaman paksa dan jam operasi. Jam pemadaman paksa terbobot adalah jam yang disebabkan oleh pemadaman yang tidak direncanakan yang dibobot dengan besar kapasitas yang ada.

Nilai pemadaman paksa diberikan dalam persentase, sementara nilai pemadaman yang direncanakan (misal karena renovasi) diberikan dalam minggu per tahun.

Masa Pakai Teknis
Masa pakai teknis adalah waktu yang diharapkan dimana pembangkit energi masih bisa dioperasikan, atau mendekati spesifikasi kinerja aslinya, asalkan dilakukan pengoperasian dan perawatan normal. Selama masa pakai ini, beberapa parameter kinerja mungkin terdegradasi secara bertahap namun tetap berada dalam batas yang dapat diterima. Misalnya, efisiensi pembangkit listrik sering sedikit menurun (beberapa persen) setelah sekian tahun, dan biaya operasi dan pemeliharaan meningkat akibat keausan dan degradasi komponen dan sistem. Pada akhir masa pakai, frekuensi masalah operasional dan risiko kerusakan yang tidak terduga diperkirakan akan menyebabkan factor ketersediaan menjadi rendah dan/atau biaya operasi dan pemeliharaan tinggi yang tidak dapat

diterima. Pada saat ini, pembangkit tersebut akan dinonaktifkan atau menjalani perpanjangan masa pakai, yang menyiratkan suatu renovasi besar terhadap komponen dan sistem sebagaimana diperlukan untuk membuat pembangkit kembali berkinerja dan siap untuk periode operasi berikut yang baru.

Masa pakai teknis yang tercantum dalam katalog ini adalah nilai teoritis yang melekat pada setiap teknologi, berdasarkan pengalaman. Dalam prakteknya, pembangkit spesifik dengan teknologi serupa bisa beroperasi untuk waktu yang lebih pendek atau lebih lama. Strategi untuk pengoperasian dan pemeliharaan, misal frekuensi jam operasi, start up, dan investasi ulang yang dilakukan setelah bertahun-tahun, akan sangat mempengaruhi umur masa pakai sebenarnya.

Waktu Konstruksi
Waktu dari keputusan investasi final hingga komisioning selesai, dinyatakan dalam tahun

Persyaratan Lahan
Jika relevan, kebutuhan ruang dicantumkan (1000 m2 per MW). Persyaratan lahan antara lain bisa digunakan untuk menghitung sewa tanah, yang tidak termasuk dalam pembiayaan karena biaya tersebut bergantung pada lokasi pembangkit.

Faktor Kapasitas Tahunan Rata-Rata
Untuk teknologi pembangkit listrik non-termal, ditampilkan faktor kapasitas tahunan rata-rata tipikal. Faktor kapasitas tahunan rata-rata merupakan pembangkitan listrik neto tahunan rata-rata dibagi dengan pembangkitan listrik neto tahunan teoritis, jika pembangkit tersebut beroperasi pada kapasitas penuh sepanjang tahun. Jumlah jam beban penuh ekivalen per tahun dihitung dengan mengalikan faktor kapasitas tersebut dengan 8760 jam, yang merupakan jumlah jam dalam setahun.

Faktor kapasitas untuk teknologi seperti surya, bayu dan tenaga air sangat tergantung lokasi. Dalam kasus ini, faktor kapasitas tipikal dilengkapi dengan informasi tambahan, misalnya peta atau tabel, yang menjelaskan bagaimana kapasitasnya akan bervariasi menurut lokasi geografis pembangkit listrik. Informasi ini biasanya terintegrasi dalam deskripsi teknologi singkat

Faktor kapasitas teoritis merepresentasikan realisasi produksi listrik dengan asumsi tidak ada pemadaman terencana atau paksa. Realisasi beban puncak mempertimbangkan pemadaman terencana dan paksa.

Konfigurasi Ramping (Perubahan Kapasitas yang Cepat)

Konfigurasi ramping listrik dari teknologi pembangkit digambarkan dengan 5 parameter:

A. Ramping (% dari kapasitas pembangkit nominal per menit)
B. Beban minimum (% dari beban penuh).
C. Waktu warm start up, (jam)
D. Waktu cold start up, (jam)

Untuk beberapa teknologi, parameter ini tidak relevan, misal jika teknologinya bisa naik cepat ke beban penuh seketika itu juga dalam mode on/off

Parameter A adalah kualitas cadangan putaran (spinning reserve); yaitu kemampuan untuk naik dan turun dengan cepat untuk memenuhi beban yang diperlukan dan fluktuasi frekuensi.

Parameter B adalah beban minimum dimana pembangkit masih bisa dioperasikan, karena alasan stabilitas di boiler dan/atau ruang pembakaran.

Parameter C menunjukkan kemampuan pembangkit listrik untuk start up ketika suhu komponen (boiler, turbin, dan lannya) berada di atas kondisi sekelilingnya. Kondisi ini dipenuhi ketika pembangkit listrik termal sudah menganggur tidak beroperasi selama waktu yang terbatas, biasanya selama beberapa jam.

Parameter D menunjukkan kemampuan pembangkit listrik untuk start up ketika suhu komponen (boiler, turbin, dan lainnya) sama dengan kondisi sekelilingnya. Kondisi ini dipenuhi ketika pembangkit listrik sudah menganggur tidak beroperasi dalam waktu yang lama, biasanya sehari atau lebih.

Lingkungan

Pembangkit harus dirancang dengan mengikuti regulasi yang saat ini berlaku di Indonesia. Regulasi terakhir yang terkait lingkungan diterbitkan tahun 2019 (Peraturan Menteri Lingkungan Hidup dan Kehutanan Nomor P.15). Regulasi tersebut menyatakan nilai maksimum yang dijinkan untuk emisi Sulfur Dioksida, Nitrogen Oksida, Partikulat dan Merkuri seperti yang ditampilkan pada tabel di bawah ini.

No	Parameter	Batas Ambang Atas		
		Batubara (mg/Nm^3)	Gasoil (mg/Nm^3)	Gas Bumi (mg/Nm^3)
1	Sulfur Dioksida	200	350	25
2	Nitrogen Dioksida	200	250	100
3	Partikulat (PM)	50	30	10
4	Merkuri (HG)	0.03	-	-

Nilai emisi CO2 tidak disebutkan di katalog ini, namun hal tersebut bisa dihitung oleh pembaca dengan menggabungkan data bahan bakar dengan data efisiensi teknologi.

Jika relevan, misalnya untuk turbin gas, emisi metana (CH4) dan Nitrogen Oksida (N2O), yang merupakan gas rumah kaca dengan potensi tinggi, harus dinyatakan dalam gram per GJ bahan bakar atau dalam mg/Nm^3 bahan bakar

Emisi partikulat dinyatakan sebagai PM 2.5 dalam gram per GJ bahan bakar. Emisi SOx dihitung berdasarkan kandungan belerang dalam bahan bakar berikut ini:

	Batubara	Fuel Oil	Gasoil	Gas Bumi	Kayu	Limbah	Biogas
Sulfur (kg/GJ)	0.35	0.25	0.07	0.00	0.00	0.27	0.00

Kandungan sulfur atau belerang dapat bervariasi untuk berbagai jenis produk batubara. Kandungan belerang batubara dihitung dari kandungan berat belerang maksimum sebesar 0,8%.

Untuk teknologi dimana peralatan desulfurisasi dipasang (biasanya pembangkit listrik besar), derajat desulfurisasi dinyatakan dalam persentase.

Emisi NOx mencakup NO_2 dan NO dimana NO dikonversi menjadi NO_2 dalam berat ekivalen. Emisi NOx juga dinyatakan dalam g/GJ bahan bakar.

Data Keuangan

Semua data keuangan merupakan harga tetap dalam USD, mengikuti tingkat harga di tahun 2022 dan tidak termasuk pajak pertambahan nilai (PPN) atau pajak lainnya. Saat proses membandingkan and mengkonversi data keuangan antara tahun-tahun dengan harga yang berbeda, kami turut mempertimbangkan tingkat inflasi. Jika data keuangan yang tersedia dalam mata uang lain , data tersebut akan dikonversikan ke USD terlebih dahulu dengan mempertimbangkan kurs yang sesuai:

Kurs rata-rata tahunan antara IDR dan USD
(sumber: Bank Dunia, 2023)

Tahun	**IDR ke USD**
2007	9,419
2008	10,950
2009	9,400
2010	9,090
2011	8,770
2012	9,386
2013	10,461
2014	11,865
2015	13,389
2016	13,308
2017	13,381
2018	14,237
2019	14,148
2020	14,582
2021	14,308
2022	14,849

Biaya Investasi
Biaya investasi atau biaya awal sering diberikan dengan basis dinormalisasi, misal biaya per MW. Biaya nominal adalah biaya investasi total dibagi dengan kapasitas pembangkit neto, yaitu kapasitas yang dikirm ke jaringan atau grid.

Jika memungkinkan, biaya investasi harus diperinci menjadi biaya peralatan dan biaya pemasangan. Biaya peralatan meliputi pembangkit itu sendiri, termasuk fasilitas lingkungan, sedangkan biaya pemasangan mencakup bangunan, koneksi jaringan dan pemasangan peralatan.

Beberapa organisasi berbeda menggunakan sistem akun yang berbeda untuk menentukan unsur perkiraan biaya investasi. Karena tidak ada nomenklatur yang digunakan secara universal, biaya investasi tidak selalu mencakup hal yang sama. Sebenarnya, kebanyakan dokumen referensi tidak menyebutkan unsur biaya yang tepat, sehingga menimbulkan ketidakpastian yang mempengaruhi validitas perbandingan biaya. Selain itu, banyak studi gagal melaporkan tahun harga konstan dari suatu perkiraan biaya.

Dalam laporan ini, biaya investasi mencakup semua peralatan fisik, yang biasanya disebut harga rekayasa, pengadaan dan konstruksi (*Enginering, Procurement and Construction* atau EPC) atau biaya *overnight*. Biaya koneksi jaringan termasuk di dalamnya, namun penguatan tidak disertakan. Di sini diasumsikan bahwa panjang koneksi ke jaringan berada dalam jarak yang wajar.

Biaya sewa atau pembelian tanah tidak termasuk, namun bisa dikaji berdasarkan persyaratan lahan yang ditentukan pada data energi/teknis. Alasan mengapa lahan tidak secara langsung disertakan karena sebagian besar lahan tidak kehilangan nilainya dan dapat dijual kembali setelah pembangkit listrik habis masa pakainya dan telah dinonaktifkan.

Biaya pra pengembangan dari pemilik (administrasi, konsultasi, manajemen proyek, persiapan tapak, dan persetujuan oleh pihak berwenang) dan bunga selama konstruksi tidak termasuk. Biaya pembongkaran pembangkit yang sudah ditutup juga tidak termasuk. Biaya dekomisioning bisa diimbangi dengan nilai sisa dari asset

Biaya Ekspansi Jaringan
Seperti yang telah disebutkan, biaya koneksi ke jaringan disertakan, namun ada kemungkinan biaya seperti ekspansi dan penguatan jaringan seperti penambahan asset baru ke jaringan (generator, kompensator, kabel listrik, dan sebagainya) tidak termasuk dalam data yang disajikan.

Siklus Bisnis
Siklus bisnis mengikuti tren ekonomi umum dan lintas sektoral. Sebagai contoh, biaya peralatan energi melonjak pada tahun 2007-2008 sehubungan dengan merebaknya krisis keuangan. Dalam sebuah studi yang menilai biaya pembangkitan di Inggris pada tahun 2010, Mott MacDonald melaporkan hal itu

Setelah satu dekade berfluktuasi antara $ 400 dan $ 600, harga EPC per kW untuk PLTGU meningkat tajam pada tahun 2007 dan 2008 hingga mencapai puncaknya sekitar $ 1250 / kW pada Triwulan ke-3 tahun 2008. Harga puncak ini mencerminkan harga tender: tidak ada transaksi aktual yang dilakukan pada harga ini.

Variasi yang belum pernah terjadi sebelumnya tersebut jelas membuat sulit untuk membandingkan data dari beberapa tahun terakhir. Selain itu, memprediksi penyebaran resesi global dan dampaknya terhadap rantai pasokan yang kompleks (seperti krisis Covid-19 2020) merupakan tantangan. Namun, katalog saat ini perlu mengacu pada beberapa sumber dan mengasumsikan arah di masa depan. Pembaca dihimbau untuk mengingat Karena keterlibatan berbagai pemangku kepentingan dalam proses pengumpulan data hal ini saat membandingkan biaya berbagai teknologi.

Skala Ekonomi
Biaya per unit pembangkit listrik yang lebih besar biasanya lebih rendah daripada pembangkit yang lebih kecil. Ini adalah efek dari 'skala ekonomi'. Hubungan empiris antara ukuran pembangkit listrik dan biayanya dianalisis dalam artikel "Skala Ekonomi di Pembangkit Listrik" dalam Majalah Power Engineering edisi Agustus 1977 (hlm. 51). Persamaan dasar yang menghubungkan biaya dan ukuran dari dua pembangkit listrik yang berbeda adalah:

$$C\_1/C\_2 = (P\_1/P\_2)\hat{}a$$

Where: C_1 = Biaya investasi pembangkit 1 (misal dalam jutaan US$)
C_2 = Biaya investasi pembangkit 2
P_1 = Kapasitas pembangkit 1 (misal dalam MW)
P_2 = Kapasitas pembangkit 2
a = Faktor proporsionalitas

Selama bertahun-tahun, faktor proporsionalitas rata-rata sekitar 0,6, tetapi jadwal proyek yang diperpanjang bisa menyebabkan faktor tersebut meningkat. Namun, jika digunakan dengan hati-hati, aturan ini dapat diterapkan untuk konversi data dalam katalog ini ke ukuran kapasitas pembangkit lain selain yang disebutkan. Penting bahwa pembangkit pada dasarnya identik dalam hal teknik konstruksi, desain, dan kerangka waktu dan satu-satunya perbedaan yang signifikan adalah ukuran.

Untuk pembangkit listrik yang sangat besar, seperti pembangkit listrik tenaga batu bara terpusat tradisional, kemungkinan besar keluaran daya maksimum telah mencapai titik tertinggi. Sebaliknya, pembangunan beberapa unit di lokasi yang sama dapat memberikan penghematan tambahan dengan berbagi peralatan balance of plant (BOP) dan infrastruktur pendukung. Biasanya, sekitar 15% penghematan biaya investasi per MW dapat dicapai untuk PLTGU dan PLTU besar dari pengaturan unit kembar versus satu unit ("Proyeksi Biaya Pembangkit Listrik", IEA, 2010). Semua data keuangan dalam katalog ini untuk pembangkit satu unit (kecuali untuk ladang bayu dan fotovoltaik surya), jadi seseorang bisa mengurangi 15% dari biaya investasi, jika pabrik yang dipertimbangkan sangat besar. Kecuali dinyatakan lain, pembaca katalog bisa menerapkan faktor proporsionalitas 0,6 untuk menentukan biaya investasi pembangkit dengan kapasitas lebih tinggi atau lebih rendah daripada kapasitas tipikal yang ditentukan untuk teknologi tersebut. Untuk setiap teknologi, rangkaian produk yang relevan (kapasitas) ditentukan.

Biaya Operasi dan Pemeliharaan (Biaya *O&M*)

Bagian tetap dari O&M dihitung sebagai biaya per kapasitas pembangkit per tahun ($ / MW / tahun), di mana kapasitas pembangkit adalah yang ditentukan di awal bab ini dan dinyatakan dalam tabel. Ini mencakup semua biaya, yang tidak bergantung pada berapa jam pabrik dioperasikan, misal administrasi, staf operasional, pembayaran untuk perjanjian layanan O&M, biaya jaringan atau sistem, pajak properti, dan asuransi. Reinvestasi atau investasi ulang apa pun yang diperlukan untuk menjaga pabrik tetap beroperasi dalam masa pakai teknis juga disertakan, sedangkan investasi ulang untuk memperpanjang umur operasional di luar masa pakai teknis tidak termasuk. Investasi ulang menggunakan diskonto dengan tingkat diskonto tahunan 4% secara riil. Biaya investasi ulang untuk memperpanjang umur tanaman bisa disebutkan dalam catatan jika data tersedia.

Biaya O&M variabel ($ / MWh) termasuk konsumsi bahan pembantu (air, pelumas, aditif bahan bakar), perawatan dan pembuangan residu, suku cadang, dan perbaikan dan pemeliharaan terkait keluaran (namun bukan biaya yang ditanggung oleh jaminan dan asuransi). Biaya pemeliharaan yang direncanakan dan tidak direncanakan mungkin termasuk dalam biaya tetap (misalnya pekerjaan pemeliharaan tahunan terjadwal) atau biaya variabel (misalnya pekerjaan yang tergantung pada waktu pengoperasian sebenarnya), dan dibagi sesuai porsinya.

Biaya bahan bakar tidak termasuk.
Perlu diperhatikan bahwa biaya O&M sering kali berkembang seiring waktu. Oleh karena itu, biaya O&M yang dinyatakan adalah biaya rata-rata selama masa pakai.

Appendix A: Difference in Qualitative & Quantitative Descriptions for Storage Technologies

In the introduction of this catalogue the descriptions' focus is on the electricity generation technologies, therefore, some of the descriptions are not usable for the storage technologies. In this appendix, specific definitions for the storage technologies are given for those definitions that differ from the electricity generation technologies.

This catalogue presents two types of electrical storage; nevertheless, there are a selection of commercial storage technologies. Figure 1 shows how the different technologies perform on storage capacities and timescales. It gives an idea of how they differ from one another in terms of storage capacity and discharge time, and therefore how they can be useful for different applications.

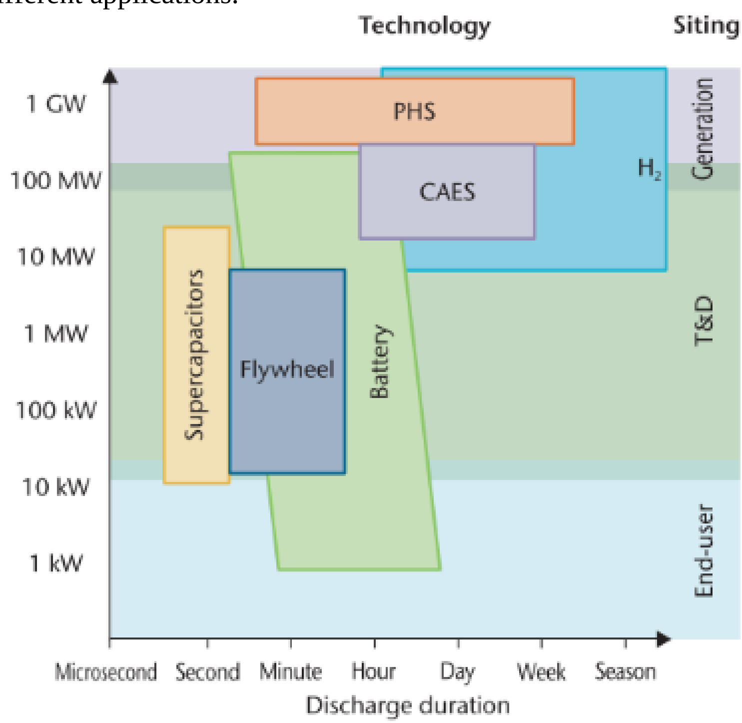


Figure 8:Electricity storage technologies [App.1]

[App.1] M. van der Hoeven, Technology Roadmap Hydrogen and Fuel Cells. International Energy Agency, 2015.

Qualitative description specific for energy storage technologies

Typical characteristics and capacities

The characteristics are stated for a single unit capable of providing the storage service needed. In the case of modular technologies such as batteries, the unit is represented by a typical size of battery installation, to provide the service described.

The typical characteristics expressed are:

- Energy storage capacity, in MWh: amount of energy that can be stored
- Input and output capacities, in MW: rate at which the energy can either be charged or discharged
- Energy density and specific energy, in Wh/m^3 and Wh/kg respectively

For some storage technologies, there is a certain amount of energy that should be constantly kept in the storage unit to ensure low degradation or to maintain specific conditions (e.g. pressure, temperature).

For example, in electrical batteries there could be a lower bound for the state of charge (SOC). In such cases, only the "active storage capacity" is specified, meaning the amount of energy between maximum and minimum level. Information regarding the minimum required amount of energy stored is also explained here.

Also ranges for the different parameters could be indicated here if the technology has various typical sizes.

Typical storage period
Qualitative expression of how long the energy is typically stored in the unit, which is closely related to the application and the services provided. The storage period is typically in the range from hours or days to longer periods such as months or years.

Quantitative description specific for energy storage technologies

Energy/technical data

Energy storage capacity
The storage capacity, preferably a typical capacity (not maximum capacity), represents the size of a standard unit in terms of energy stored. It refers to a single unit capable of providing the storage service needed, e.g. a hydro plant, a heat tank or a battery installation.

In the case of a modular technology such as batteries, a typical size based on historical installations, or the market standard is chosen as a unit. Different sizes may be specified in separate tables, e.g. small, medium, large battery installation.

As explained under "Typical characteristics", the energy storage capacity refers only to the active part of the storage unit, i.e. the energy that can be used, and not to the rated storage capacity of the storage. Additional information on the minimum level of energy required is found in the notes.

The unit MWh is used for energy storage capacity.

Output and input capacity
The nominal output capacity is stated for a full unit and refers to the active part of the storage. Any other information regarding the minimum level is specified in the notes. It is given as net output capacity in continuous operation, i.e. gross output capacity minus own consumption.

The nominal input capacity is stated for a full unit as well. In case it is equal to the output capacity, the value specified will be the same.

The unit MW is used for all output and input capacities.

Charge and discharge efficiencies (round trip efficiency)
The efficiencies of the charging and discharging processes are stated separately in percentage where possible. The round-trip efficiency is the product of charging and discharging efficiencies and expresses the fraction of the input energy, which can be recovered at the output, assuming no losses during the storage period. It represents the ratio

between the energy provided to the user and the energy needed to charge the storage system. For electricity storage, it is intended as AC-AC value, therefore including losses in the converters and other auxiliaries. The round-trip efficiency enables comparisons of different storage technologies with respect to efficiency of the storage process. However, not including the losses during the storage period, it does not give a complete picture.

Energy losses during storage
The energy lost from the storage unit due to losses in a specific time horizon is specified here.

Technologies with different storage periods will show very different behavior with respect to energy losses. Therefore, the period is chosen based on the characteristics of the technology (e.g. % losses/hour, % losses/day or % losses/year).

Losses are expressed as a percentage of the energy storage capacity (as defined above) lost over the timeframe chosen.

Auxiliary electricity consumption
Auxiliary consumption expresses the consumption of electricity from such equipment. For electricity storage, this component is already included in the overall round-trip efficiency (AC-AC).

Regulation ability
The electricity regulation capabilities of the storage technologies are described by two parameters:

- Response time from idle to full-rated discharge (sec)
- Response time from full-rated charge to full-rated discharge (sec)

The response time from idle to full-rated discharge is defined as the time, in seconds, the electricity storage takes to reach 100% of the discharge capacity from idle condition. It is assumed to be equal for the charging process.

The response time from full-rated charge to full-rated discharge is defined as the time, in seconds, the electricity storage takes to go from charging at full capacity to discharging at full capacity. It is assumed to be equal in the other direction.

Financial data

Investment cost
The total investment cost is reported on a normalized basis, i.e. cost per MWh of storage capacity. It is the total investment cost divided by the energy storage capacity for one unit, stated in the datasheet.

For most of the storage technologies it is possible to identify three main cost components: an energy component, a capacity component, and other fixed costs. Where possible, total investment costs are divided into these components.

The cost of energy component includes all the cost related to the equipment to store the energy, which one would incur in case an expansion of the MWh rating of the system is needed, for example battery modules, reservoirs in a pumped-hydro plant or heat tank. The cost of capacity component refers to the part of equipment which conditions or converts the energy carrier and makes it available to the user or the grid, for example converter and grid connection for a battery system, turbine/pump and grid connection for pumped-hydro plant, and heat exchanger and piping for a heat storage. This is the cost one would incur if an increase of the MW capability of

the system is required. Finally, another cost component reflects the fixed costs related to the project, such as data management and control system, project engineering, other civil works, commissioning.
Summarizing, the components considered are the following:

- Cost of Energy component (CE) [M$/MWh]: cost related to the equipment to store the energy (incl. their installation);
- Cost of Capacity component (CP) [M$/MW]: cost related to the equipment to condition or convert the energy carrier and make it available to the user or the grid (incl. their installation);
- Other project costs (Cother) [M$]: includes fixed costs which do not scale with capacity or energy, such as those for data management and control system, project engineering, civil works, buildings, site preparation, commissioning.

For storage technologies, the total investment cost is expressed in relative terms, in M$/MWh, by dividing the Total Capital Expenditure by the Energy storage capacity for one unit in MWh.

For electricity storage applications with a power-intensive service, an alternative total investment cost in M€/MW is indicated in the technology specific data, calculated by dividing the Total Capital Expenditure by the Output capacity for one unit.

Appendix B: Difference in Qualitative and Quantitative Descriptions for CO_2 Capture Technologies

In the introduction of this catalogue the descriptions' focus is on the electricity generation technologies, therefore, some of the descriptions are not usable for carbon capture and storage technologies. In this appendix specific definitions for the carbon capture and storage technologies are given for those definitions that differ from the electricity generation technologies.

Definition of the service

Carbon capture technologies (CC) are technologies that capture CO_2 from processes related to e.g. combustion or upgrading of fossil fuels and biofuels or from chemical processes in the industry (e.g. cement production), or that absorbs CO_2 directly from the air. The most common utilization of the CC technologies today consists of a capture part, where CO_2, methane and hydrogen are separated from pure natural gas. Another common use of CC is for upgrading biogas. Even if today CC is commercially available and used around the world, it has yet to become economically feasible in the power sector and in industry. The focus in this catalogue is power generation technologies, so only CC technologies used in relation to power generation are described, including description of post-combustion, pre-combustion and oxy-fuel combustion. Furthermore, CCS can be divided into Capture, Compression, Transport and Storage, which are described in separate sections.

Data sheets are only provided for the CC part. The focus is to describe the carbon capture part of the three technologies so that it is useful when delivering technology data for technical energy system modelling.

Boundaries

A challenge is where to put the boundaries for the CC systems. It is desirable that this is done in the same way for all the three carbon capture systems categories. Therefore, the CC technology is described as a module. The module features the CC technology and specifies input and output. Thus, the power plant technologies or other technologies related to the CC technology are not described in this context.

Qualitative description specific for CC technologies

Input

The flue/process gas and other main materials (e.g., amines in scrubber systems), gases (e.g. O_2 in oxy-fuel combustion) and energy consumed (e.g., electricity and/or heat) by technology or facility. The moisture and CO_2 content of the flue gas and required temperature of the input heat are specified.

Auxiliary inputs, such as chemicals or enzymes assisting the process are mentioned and their contribution described, if considered relevant.

Output

The outputs are the CO_2 capture percentage (i.e., CO_2 reduction in the exhaust gas), the CO_2 purity, as well as co-product or by-products, for example process heat. Pressure of the output gases and temperature of the output heat are specified too. Other non-energy outputs may be stated such as condensate from flue gas, if relevant.

Typical capacities

The stated capacities are for a single unit capable of capturing carbon. If the range of capacities varies significantly the typical range is stated (also in the notes), and it is mentioned if the different sizes of capacity are characteristic for a specific type of plants.

Quantitative description specific for CC technologies

The data sheets present data for the CC combined with different power generation technologies.

Data set relative to the data for the power generation technology
Data for the following parameters:

- Generating capacity
- Electricity efficiency
- Forced outage
- Planned outage
- Technical lifetime
- Construction time
- CO_2 emission reduction
- Space requirement
- Nominal investment
- Fixed O&M
- Variable O&M

Data are expressed as absolute numbers of a new electricity generation plant with installed CC. In the previous version (2020), numbers were filled relative to the value of the power plant that the CC technology is installed, thereby stated with a plus (+) or a minus (-) placed before the figures indicating an increase/decrease of the parameter's value when equipped with CC. This version illustrates the actual numbers instead of relative increases or decreases, however, the link to the numbers of the related power plant is still utilised to calculate the final values. If there are blank cells in the "technology" + CC sheet which are filled in the original technology sheet instead, it indicates that no changes on the values take place when installing CC. That applies to all technical and financial data of each technology-specific sheet.
Following an example: Name plate electricity efficiency for a new Supercritical Coal plant is stated to be 38%, while the same parameter decreases by 9%-points when CC equipment is installed. The number shown in the datasheet for a new Supercritical Coal plant with CC is 29%.