Technology Data for the Indonesian Power Sector

Catalogue for Generation and Storage of Electricity

February 2021

ACKNOWLEDGEMENTS

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CONTENT

FOREWORD

This technology catalogue is a revised and updated version of the previous Indonesian technology catalogue of 2017. This new version has been prepared during 2020 by the Directorate General of Electricity in close collaboration with the Danish Embassy and the Danish Energy Agency – supported by Ea Energy Analyses and local consultant, Joko Santosa.

Close monitoring and analysis of technology trends within generation technologies have been vital parts of the research behind this report. The technological development of recent years has introduced lower prices and even new technologies into the spectrum of this report. Because of the fast development for many of the technologies, this updated version of the technology catalogue comes at a vital time, securing updated data and knowledge. The update is key to provide and establish a good understanding of technologies in terms of price and performance.

Multi-stakeholder involvement has been key in the data collection process. The technology catalogue contains data that have been scrutinised and discussed by a broad range of relevant stakeholders including PLN, DJK, MEMR and NEC. 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 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. This updated can support the work to achieve the government's long-term renewable energy and energy efficiency targets and, not least, help to increase the electrification rate in Indonesia.

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Director of Electricity Programme Development,
Directorate General Electricity

Ole Emmik Sørensen
Director of Centre for Global Cooperation,
Danish Energy Agency

Kata pengantar (BAHASA)

Katalog teknologi ini merupakan versi revisi dan terbaru dari katalog teknologi Indonesia sebelumnya yang diterbitkan pada tahun 2017. Katalog versi baru ini telah disiapkan selama tahun 2020 oleh Direktorat Jenderal Ketenagalistrikan, Kementerian Energi dan Sumber Daya Mineral bersama-sama dengan Kedutaan Besar Denmark dan Badan Energi Denmark (Danish Energy Agency) – didukung oleh Ea Energy Analyses dan konsultan lokal, Joko Santosa.

Pemantauan dan analisis yang ketat terhadap tren teknologi pembangkit telah menjadi bagian penting dari penelitian di balik laporan ini. Perkembangan teknologi pembangkit beberapa tahun terakhir telah memperkenalkan harga yang lebih rendah dan bahkan teknologi baru ke dalam spektrum laporan ini. Dikarenakan adanya perkembangan yang pesat dari banyak teknologi, versi terbaru dari katalog teknologi ini hadir pada saat yang sangat penting dan menampilkan data dan pengetahuan yang telah diperbarui. Pembaruan adalah kunci untuk memberikan dan memastikan pemahaman yang baik terhadap teknologi dari segi harga dan kinerja.

Keterlibatan dari banyak pemangku kepentingan telah menjadi kunci dalam proses pengumpulan data. Katalog teknologi ini berisi data yang telah diteliti dan dibahas oleh berbagai pemangku kepentingan terkait termasuk PLN, DJK, Kementerian ESDM dan DEN. Dengan referensi yang sama, skenario dan perencanaan energi di masa depan menjadi lebih transparan. Dalam laporan ini, semua pemangku kepentingan telah sepakat bahwa data yang dipublikasikan merupakan estimasi terbaik berdasarkan tingkat pengetahuan saat ini.

Katalog teknologi terbaru ini akan membantu pemodelan energi jangka panjang di Indonesia dan mendukung lembaga pemerintah, perusahaan energi swasta, *think tank*, dan lainnya dalam mengembangkan kebijakan dan strategi bisnis yang relevan. Pembaruan katalog teknologi dapat mendukung program pemerintah dalam rangka mencapai target energi terbarukan jangka panjang dan efisiensi energi serta, tidak kalah pentingnya, membantu meningkatkan rasio elektrifikasi 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 is associated with a high level of uncertainty. All technologies have been grouped within one of four categories of technological development (described in 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 are 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 for 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.

Qualitative description

The qualitative description describes the key characteristic of the technology as concise as possible. The following paragraphs are included if found relevant for the technology.

Technology description
Brief description of how the technology works and for which purpose.

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

Output
The output of the technologies in the catalogue is electricity. Other output 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, that renewable energy technologies mitigate climate risk and enhance 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. The table below summarizes the regulation. By local content requirement is meant the amount of work and/or resources that must be applied in Indonesia.

Summarizing the local requirement regulation.

Type	Capacity	Local Content Requirement (%)		
		Goods (minimum)	Services	Combined Goods and Services (minimum)
Steam Power Plant	Up to 15 MW	67.95	96.31	70.79
	15 – 25 MW	45.36	91.99	49.09
	25 – 100 MW	40.85	88.07	44.14
	100 – 600 MW	38.00	71.33	40.00
	> 600 MW	36.10	71.33	38.21
Hydro Power Plant	Up to 15 MW	64.20	86.06	70.76
	15 – 50 MW	49.84	55.54	51.60
	50 – 150 MW	48.11	51.10	49.00
	> 150 MW	47.82	46.98	47.60
Geothermal Power Plant	Up to 15 MW	31.30	89.18	42.00
	5 – 10 MW	21.00	82.30	40.45
	10 – 60 MW	15.70	74.10	33.24
	60 – 110 MW	16.30	60.10	29.21
	> 110 MW	16.00	58.40	28.95
Gas Power Plant	Up to 100 MW	43.69	96.31	48.96
Gas Combined Cycle Power Plant	Up to 50 MW	40.00	71.53	47.88
	50 – 100 MW	35.71	71.53	40.00

	100 – 300 MW	30.67	71.53	34.76
	> 300 MW	25.63	71.53	30.22
Solar PV Power Plant	Decentralized off-grid	39.87	100.00	45.90
	Centralized off-grid	37.47	100.00	43.72
	Centralized on-grid	34.09	100.00	40.68

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 2020 (base year). In this catalogue, it is expected that cost reductions and improvements of performance are realized in the future.

This section accounts for the assumptions underlying the improvements assumed in the data sheet 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.

Category 1. 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.

Category 2. 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 is still attached with high uncertainty, since development and customization is still needed (e.g. gasification of biomass).

Category 3. *Commercial technologies with moderate deployment* so far. 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)

Category 4. *Commercial technologies, with large deployment* so far. 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).
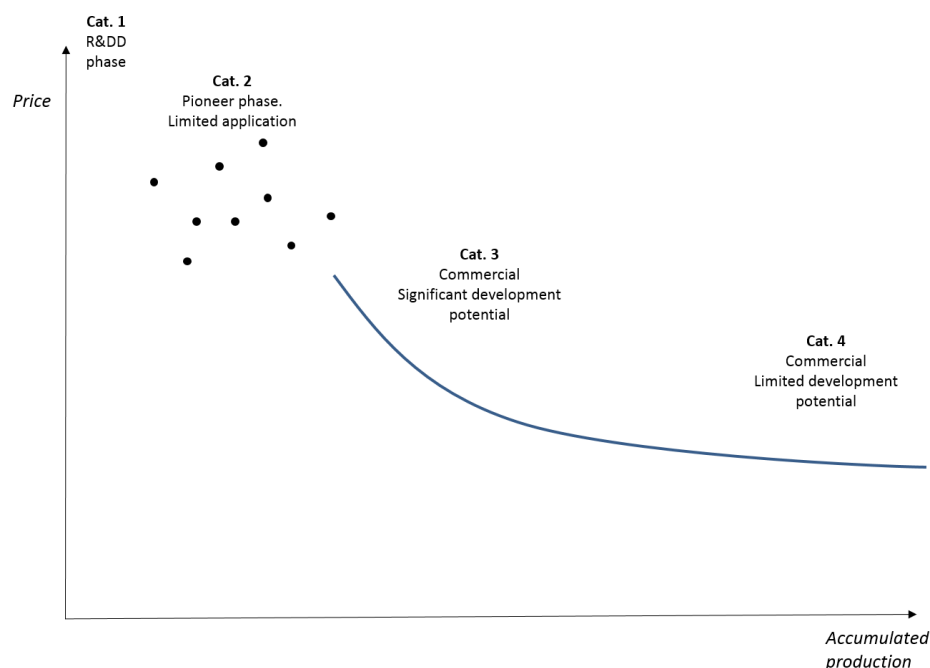
Technological development phases. Correlation between accumulated production volume (MW) and price.

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 based on the learning curve approach is added at the bottom of the table to show cost trends derived from the application of the learning curve approach (see the Appendix for a more detailed discussion). Technological learning is based on a certain learning rate and on a capacity deployment defined as the average of the IEA's Stated Policies and Sustainable Development. The single technology is given a normalized cost of 100% in 2020 (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 [$MUSD_{2019}$/MW]		2018	2020	2030	2050
Catalogues	**New Catalogue (2020)**				
	Existing Catalogue (2017)				
Indonesia data	Local data I				
	Local data II				
International data	Danish technology catalogue				
	IRENA				
	IEA WEO 19				
Projection	Learning curve – cost trend [%]				

As for the uncertainty of investment cost data, the following approach was followed: for 2020 the lower and upper bound of uncertainty are derived from the cost span in the various sources analysed. For 2050, the central estimate is based on a learning rate of 12.5% and an average capacity deployment from the STEPS and SDS scenarios of the World Energy Outlook 2019 (see Appendix: forecasting the cost of electricity production technologies). The 2050 uncertainty range combines cost spans of 2020 with the uncertainty related to the technology deployment and learning: a learning rate range of 10-15% and the capacity deployment pathways proper of STEPS and SDS scenarios are considered to evaluate the additional uncertainty. The upper bound of investment cost, for example, will therefore be calculated as the upper bound for 2020 plus a cost development based on the scenario with a learning rate of 10% combined with the scenario with the lowest deployment towards 2050.

Examples of current projects
Recent technological innovations in full-scale commercial operation 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 it is imperative that data is actually comparable. As an example, economic data is stated in the same price level and value added taxes (VAT) or other taxes are excluded. The reason for this is that the technology catalogue should reflect the socio-economic cost for the Indonesian society. 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. Also, it is essential that data be given for the same years. Year 2020 is the base for the present status of the technologies, i.e. best available technology at the point of commissioning.

All costs are stated in U.S. dollars (USD), price year 2019. 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. When converting costs from a year X to USD2019 the following approach is recommended:

1. If the cost is stated in IDR, convert to USD using the exchange rate for year X (first table below).
2. Then convert from USD in year X to USD in 2019 using the relationship between the US Producer Price Index for "Engine, Turbine, and Power Transmission Equipment Manufacturing" of year X and 2019 (second table below).

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

US Producer Price Index for "Turbine, and Power Transmission Equipment Manufacturing", Index Dec 1984 =100. This industry comprises establishments primarily engaged in manufacturing turbines, power transmission equipment, and internal combustion engines (except automotive gasoline and aircraft). Source: U.S. Bureau of Labor Statistics.

Year	Producer Price Index
2007	152.6
2008	162.9
2009	174.6
2010	174.6
2011	177.7
2012	179.0
2013	180.9
2014	183.0
2015	184.6
2016	181.8
2017	181.8
2018	184.2
2019	189.0

The construction time, which is also specified in the data sheet, represents the time between the financial when closure is achieved, i.e. when financing is secured, and all permits are at hand, and the point of commissioning.

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, which 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 data sheet 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 years 2020 and 2050 and for selected techno-economic parameters (financial data, key performance data). The level of uncertainty is illustrated by providing a lower and higher bound indicating a confidence interval of 90%. The uncertainty it 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. The reason is, that for coal power it is not obvious, which type of product is the market standard in Indonesia.

The level of uncertainty needs only to be stated for the most critical figures such as for example investment costs and efficiencies.

Most data in the datasheets is 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.

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

Technology	Name of technology								
	2020	2030	2050	Uncertainty (2020)		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 (g per GJ fuel)									
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									

References:

1

2

Notes:

A

B

Energy/technical data

Generating capacity

The capacity is stated for both a single unit, e.g. a single wind turbine or gas engine, and for the total power plant, for example 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 generator) minus own consumption (house load), equal to capacity available to the grid.

The unit MW is used for electric generation capacity (kW for small plants), 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. 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 are made, economy of scale effects need to be considered (see the section about investment cost).

Energy efficiencies
Efficiencies for all thermal plants are expressed in percentage at <u>lower calorific heat value</u> (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 is decreasing 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 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.

Forced outage is given in per cent, 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 takes place. During this lifetime, some performance parameters may degrade gradually but still stay within acceptable limits. For instance, power plant efficiencies often decrease slightly (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.

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 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 is 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 in the brief technology description.

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

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 regulation that is 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 gas, 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 2019 and exclude value added taxes (VAT) or other taxes. There exist several approaches to estimate future costs of generation technologies. This catalogue uses the learning curves approach. This method has proven historically robust and learning rates estimates can be obtained for most

technologies. Ea Energy Analyses have prepared a separate note, "Forecasting cost of electricity production technologies", on the approach used in this catalogue, which is attached in the Appendix.

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.

If possible, the investment cost is divided into equipment cost and installation cost. Equipment cost covers the plant itself, including environmental facilities, whereas installation costs covers 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 *not* included, but may be assessed based on the space requirements specified under the energy/technical data. 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.

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 obviously make it difficult to benchmark data from the 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 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 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 noticed that O&M costs often develop over time. The stated O&M costs are therefore average costs during the entire lifetime.

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), used at vapor-dominated reservoirs. The geothermal fluid must be predominantly composed of steam in order to avoid a 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 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.
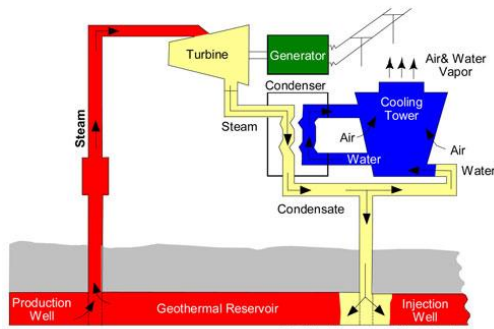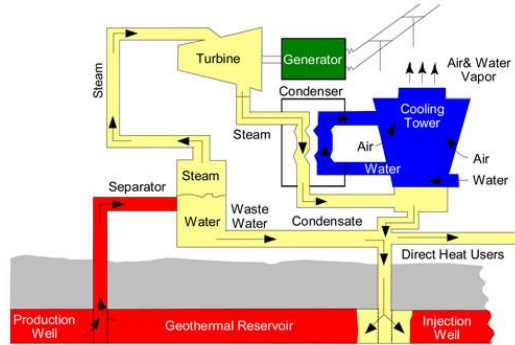
Direct and single flashed steam plants (ref. 7)
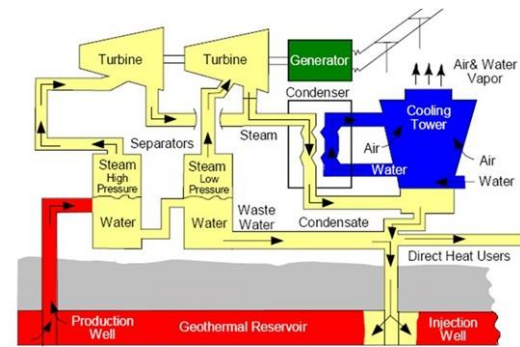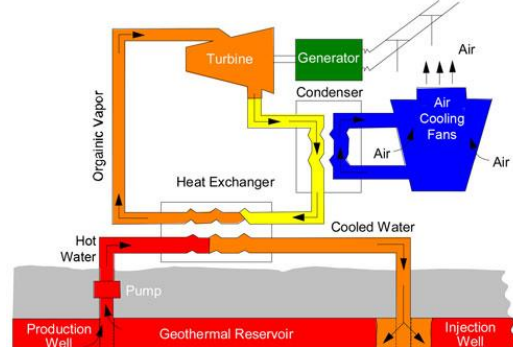
Double flashed and binary steam plants (ref. 7)
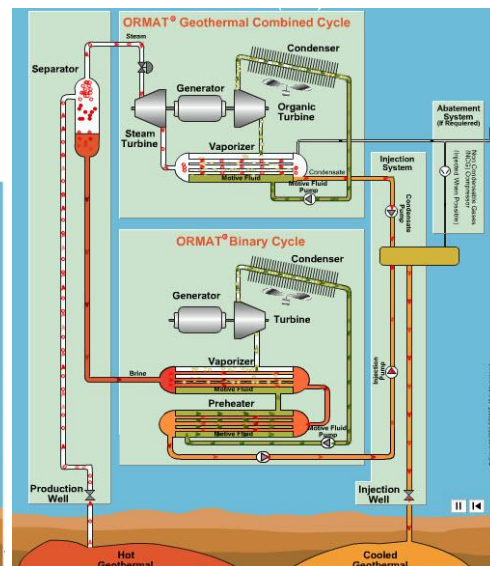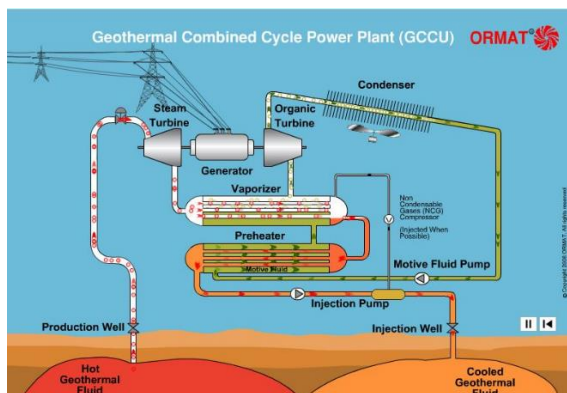
Hybrid/Combined Cycle plant (ref. 8)

The total capacity of geothermal power plants installed in 2019 in Indonesia was 2131 MW (IRENA). In the same year, geothermal power plants have generated electricity for around 14 TWh. This equals to an average capacity factor of over 75%. According to statistics of PT Indonesia Power 2015, the overall capacity factor of Kamojang, Salak and Darajat Geothermal Power Plants with total capacity of 345 MW could reach 96%. The current installed units have a capacity ranging from 2.5 to 110 MW per unit.

Indonesia has the largest geothermal resources potential in the world of about 29.5 GW, which comprises 12 GW of resources and 17.5 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 RUEN document, 2016)*

No	Islands	Resources (MW)		Reserves (MW)			Total
		Speculative	Hypothetic	Probable	Possible	Proven	(MW)
1	Sumatera	3,191	2,334	6,992	15	380	12,912
2	Jawa	1,560	1,739	4,023	658	1,815	9,795
3	Bali & Nusa Tenggara	295	431	1,179	0	15	1,920
4	Kalimantan	153	30	0	0	0	183
5	Sulawesi	1,221	318	1,441	150	78	3,208
6	Maluku	560	91	800	0	0	1,451
7	Papua	75	0	0	0	0	75
	Total	7,055	4,943	14,435	823	2,288	29,544

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 the geothermal energy should be used as 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 source 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 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 discharged. 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). 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 of 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 are 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).

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

*CO_2 and H_2S emission from geothermal power plant in Indonesia. *Total capacity in 2016*

Employment
During construction, the development of Lahendong Unit 5 and 6 and Ulubelu Unit 3 Geothermal Power Plants with total installed capacity of 95 MW have created around 2,750 jobs to 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 of improvement.

In order 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 demonstration of a binary cycle power plant has not yet be conducted. Commissioning will be conducted in mid-September 2017.

The binary power plant will use brine from 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 working fluid. For low maintenance and high reliability of the ORC, no rotating sealing are used in the conversion cycle. The feed pump will be a magnetic coupled type. 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 focus on the thermo-physical characteristic of the working fluid. For the heat removal from the ORC to the ambient by means of 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 to facilitate a factory test of the complete ORC-module prior to 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%.
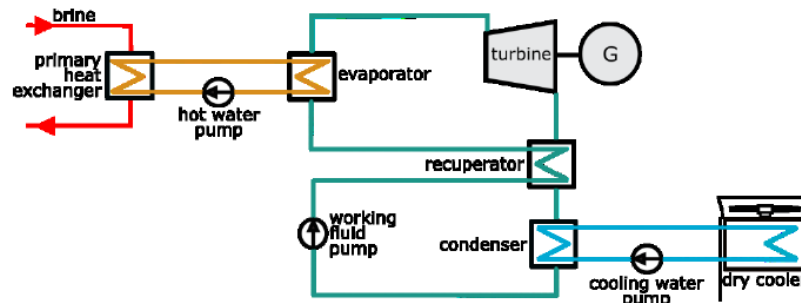
Technical concept of the demonstration power plant (ref. 4)

Investment cost estimation

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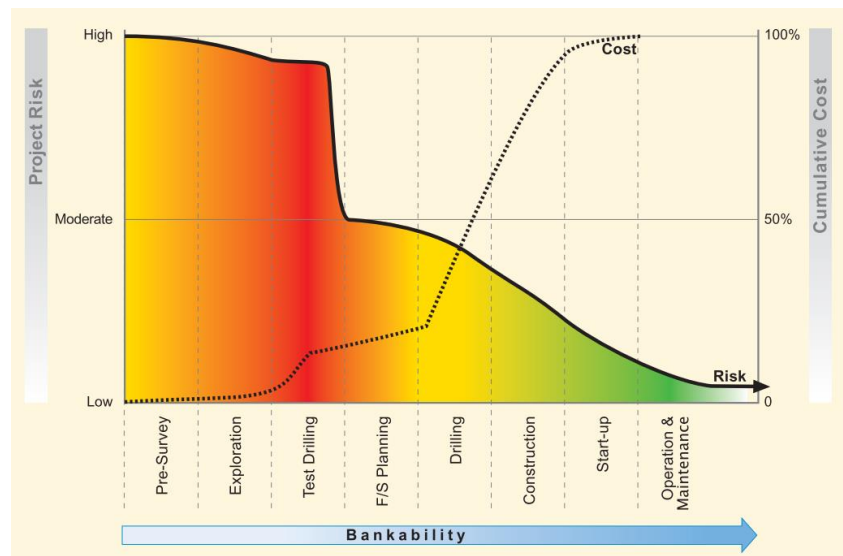
Qualitative risk and cumulative cost trends of a geothermal project. Source: Geothermal Handbook: Planning and Financing Power Generation, ESMAP, 2012.

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. The average cost gap due to the technological choice is quantified in 1 million USD/MW today. Cost data from relevant sources are reported in the table below, along with the recommended values for the investment costs.

Investment (M$/MW)		2018	2020	2030	2050
Catalogues	**New Catalogue (2020)**		**4.00** (flash) **5.00** (binary)	**3.44** (flash) **4.30** (binary)	**2.84** (flash) **3.55** (binary)
	Existing Catalogue (2017)		3.64 (flash) 4.68 (binary)	3.33 (flash) 4.37 (binary)	3.01 (flash) 4.37 (binary)
Indonesian data	ESDM[1]		5.0		
	Literature[2]		2.69		
International data	IRENA (various)	3.92		2.50	
	NREL ATB		4.40 (flash) 5.77 (binary)	3.83 (flash) 5.04 (binary)	3.47 (flash) 4.79 (binary)
	Lazard	4.6			
Projection	Learning curve – cost trend [%]	-	100%	86%	71%

[1] *ESDM presentation on "KATADATA Shifting Paradigm: Transition towards sustainable energy". Sampe L. Purba (26 August 2020)*

[2] *Insani, N.A, Analisis Keekonomian Pembangkit Listrik Tenaga Panas Bumi Kapasitas Kecil Sistem Siklus Uap, Journal of Electrical Power, 2019.*

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 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 single and dual flash steam cycle since the geothermal source is in the form of two phases (water and vapour) with enthalpy value between 1,025 and 2,000 kJ/kg. During construction period, the project will employ 2000 – 2500 people. During operation stage, number of manpower to be recruited ranges from 200 to 240 people from various fields of expertise. 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 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 is very potential for geothermal sources as a number of other bigger geothermal plants are already operational. The location of 10 MW Geothermal Power Plant is close to Dieng Unit 1 Geothermal Power Plant with installed capacity of 55 MW which is also owned by the same company. The project is currently underway. It is predicted that the plant will come online at the end of 2020. The project will 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 turbine and generator 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, with the aim of 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.
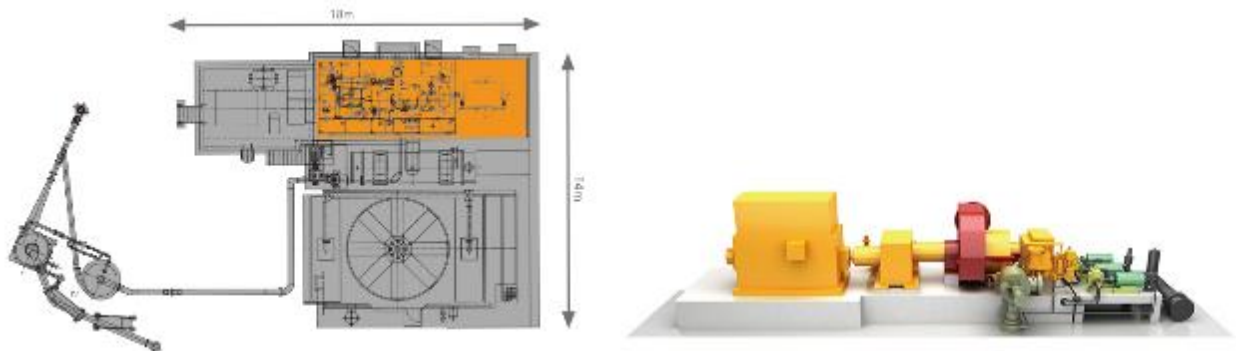
The Geoportable by Toshiba ESS (Ref. 16)

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

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 has 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 specfic capital of the plant as shown in the following figure.
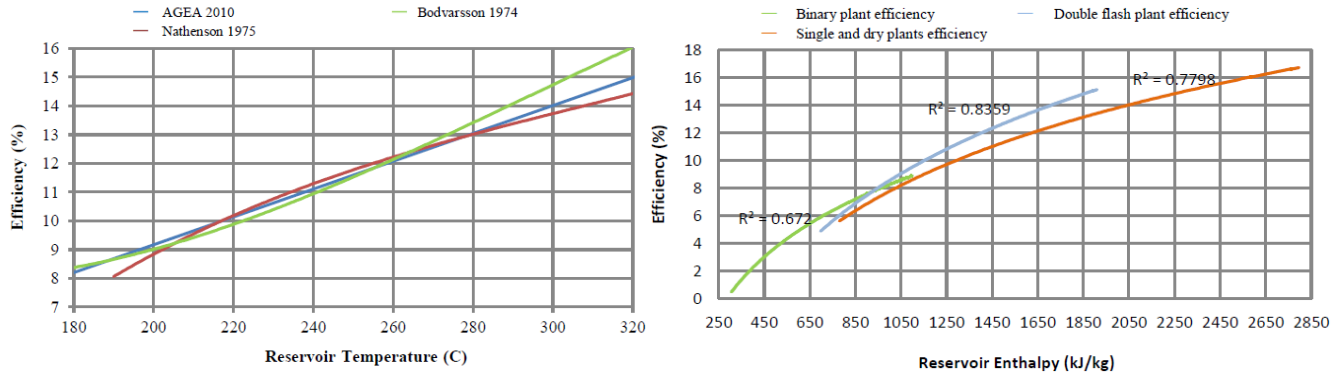
Geothermal plant efficiency as a function of temperature and enthalpy (ref. 5)
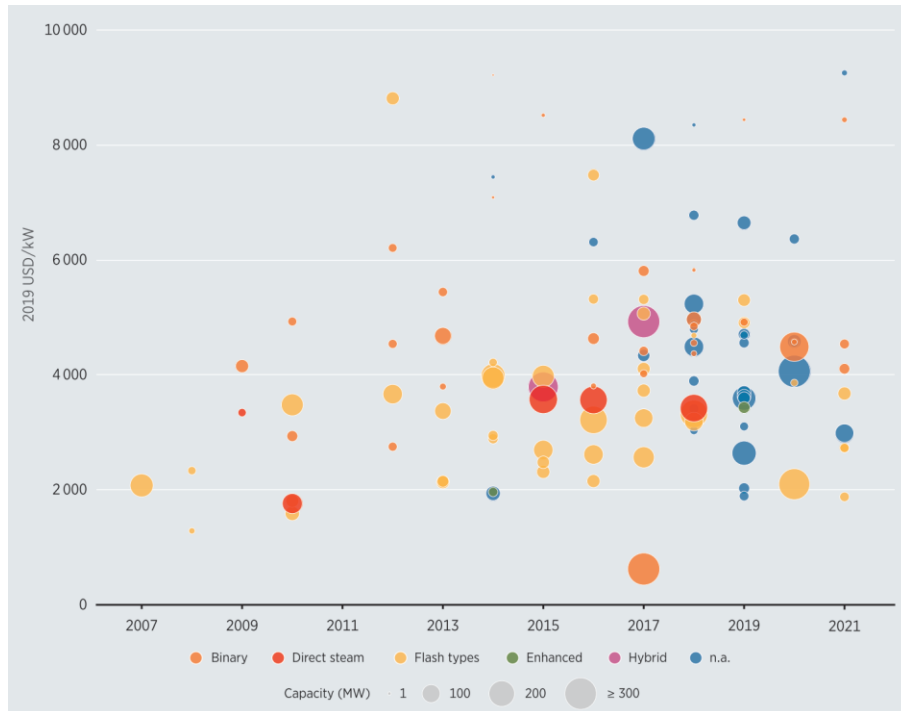
Project-level costs for geothermal projects in the world by year and plant type (ref. 10)[1].

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[1] *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).

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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 2019. 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)								
	2020	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
				Lower	Upper	Lower	Upper		
Energy/technical data									
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
Construction time (years)	2.0	2.0	2.0	1.5	3	1.5	3		1
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$_2$O (g per GJ fuel)	-	-	-	-	-	-	-	C	6
Financial data									
Nominal investment (M$/MWe)	4.00	3.44	2.84	2.70	5.75	1.70	4.55	B,D,E,F	1,2,3,4
- of which equipment	60%	60%	60%	40%	70%	40%	70%		3
- of which installation	40%	40%	40%	30%	50%	30%	50%		3
Fixed O&M ($/MWe/year)	50 000	43 000	35 500	37 500	62 500	26 600	44 400	B,D	1,4
Variable O&M ($/MWh)	0.25	0.22	0.18	0.19	0.31	0.14	0.23	B,D	1,4
Start-up costs ($/MWe/start-up)	-	-	-	-	-	-	-		
Technology specific data									
Exploration costs (M$/MWe)	0.15	0.15	0.15	0.10	0.20	0.10	0.20		7
Confirmation costs (M$/MWe)	0.15	0.15	0.15	0.10	0.20	0.10	0.20		7

References:

1 PLN, 2017, data provided the System Planning Division at PLN

2 IEA, World Energy Outlook, 2015.

3 IRENA, 2015, Renewable Power Generation Costs in 2014.

4 Learning curve approach for the development of financial parameters.

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

6 Yuniarto, et. al., 2015. "Geothermal Power Plant Emissions in Indonesia".

7 Geothermal Energy Association, 2006, "A Handbook on the Externalities, Employment, and Economics of Geothermal Energy".

8 Geothermal Energy Association, 2015, "Geothermal Energy Association Issue Brief: Firm and Flexible Power Services Available from Geothermal Facilities"

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. 3)

C Geothermal do emit H$_2$S. 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. 3 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 uncertainty 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	Geothermal power plant - small system (binary or condensing)								
	2020	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
				Lower	**Upper**	**Lower**	**Upper**		
Energy/technical data									
Generating capacity for one unit (MWe)	10	10	10	0.3	20	0.3	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	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
Construction time (years)	2.0	2.0	2.0	1,5	3	1,5	3		1
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$_2$O (g per GJ fuel)	-	-	-	-	-	-	-	B	6
Financial data									
Nominal investment (M$/MWe)	5.00	4.30	3.55	3.8	6.3	1.70	4.55	C,D,E,F	1,2,4,8
- of which equipment	60%	60%	60%	40%	70%	40%	70%		3
- of which installation	40%	40%	40%	30%	50%	30%	50%		3
Fixed O&M ($/MWe/year)	65 000	55 900	46 200	48 800	81 300	34 700	57 800	C,D	1,4
Variable O&M ($/MWh)	0.37	0.32	0.26	0.28	0.46	0.20	0.33	C,D	1,4
Start-up costs ($/MWe/start-up)	-	-	-	-	-	-	-		
Technology specific data									
Exploration costs (M$/MWe)	0.15	0.15	0.15	0.10	0.20	0.10	0.20		7
Confirmation costs (M$/MWe)	0.15	0.15	0.15	0.10	0.20	0.10	0.20		7

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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$_2$S. 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 uncertainty 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.

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).
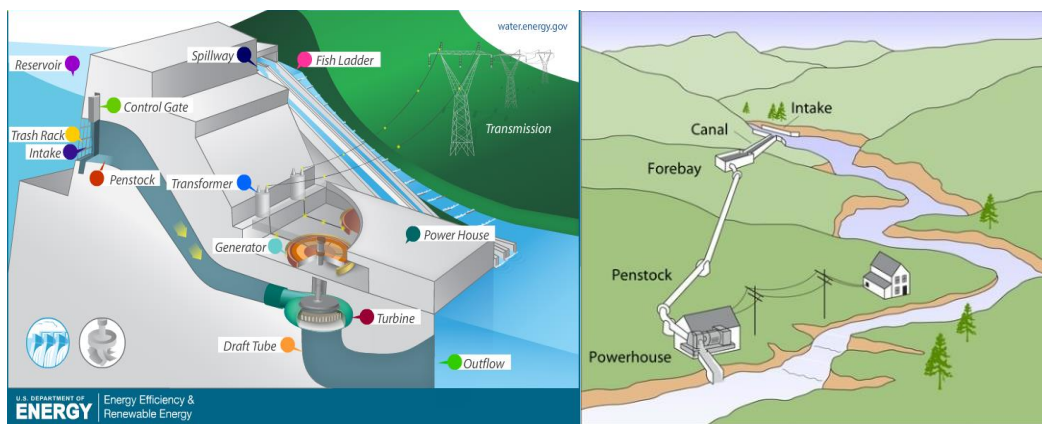
Reservoir and run-of-river hydropower plants (ref. 15)
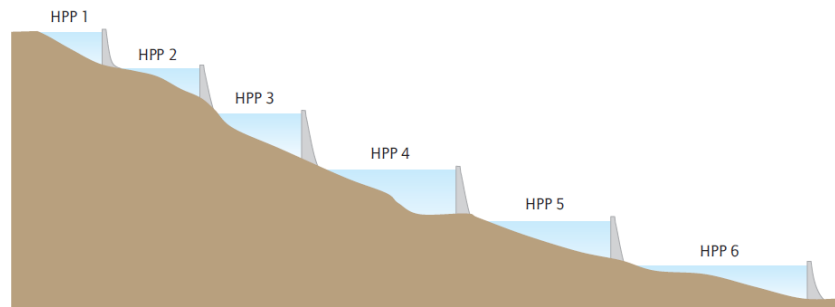
Cascading Systems (ref. 1)

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 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 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 for Indonesia is presented in 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.
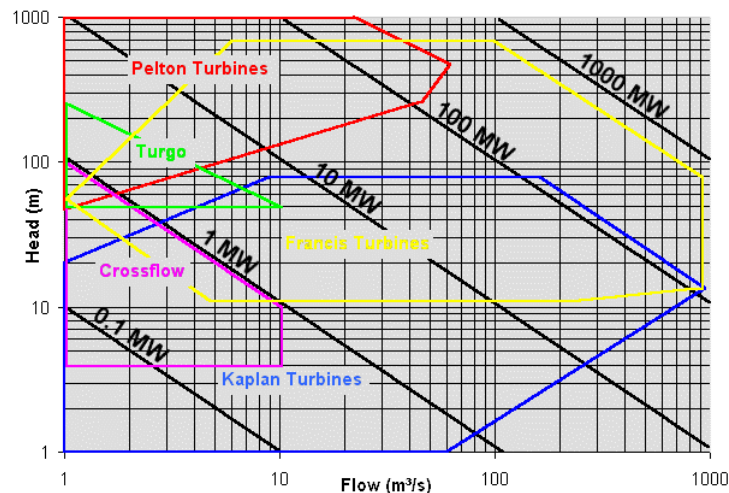
Hydropower turbine application chart (ref. 3)

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 entrance and exit of the turbine.

In 2018 the total capacity of hydropower plants installed in Indonesia was 5561 MW. At the same time, total electricity produced from hydropower plants was 17 422 GWh[2]. Hence, the capacity factor of hydropower was only 36%, despite growing with time. The reason why the average capacity factor of hydropower plants is quite low in Indonesia is that some of the plants are operated to supply peak load, especially the plants in Java islands such as Cirata and Saguling hydropower plants. Among other type of power plants, hydropower is the one that has high capability to ramp its capacity up or down to meet fluctuating demand within quite short time.

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 plants is settled at 48% in 2010-2019 (world figures), with a significant standard deviation across geography (see figure below).
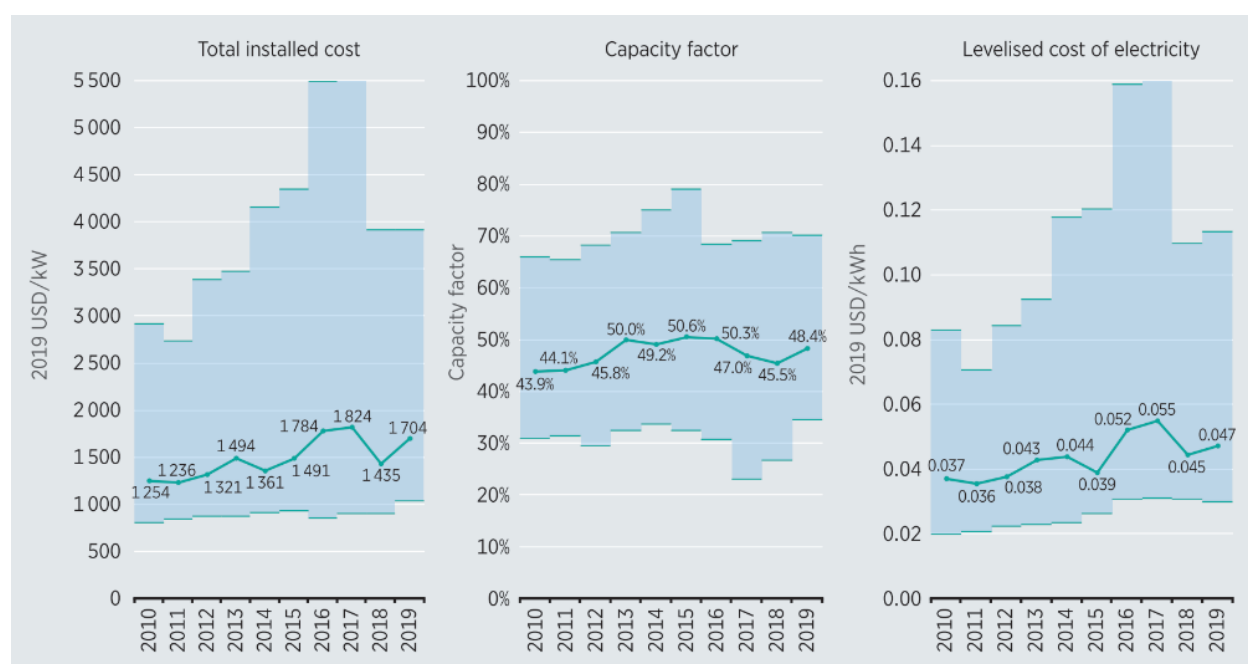
Total installed cost, capacity factor, LCOE for hydropower in the world. Blue areas represent the standard deviation from the average. Source: (IRENA, 2020).

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

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[2] Data about installed capacity and generation can be found on the IRENA website.

Input
The falling water from either reservoir or run-of-river having 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 hydro power plant (110 MW) project will provide around 2,000 – 3,000 local jobs during 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 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).
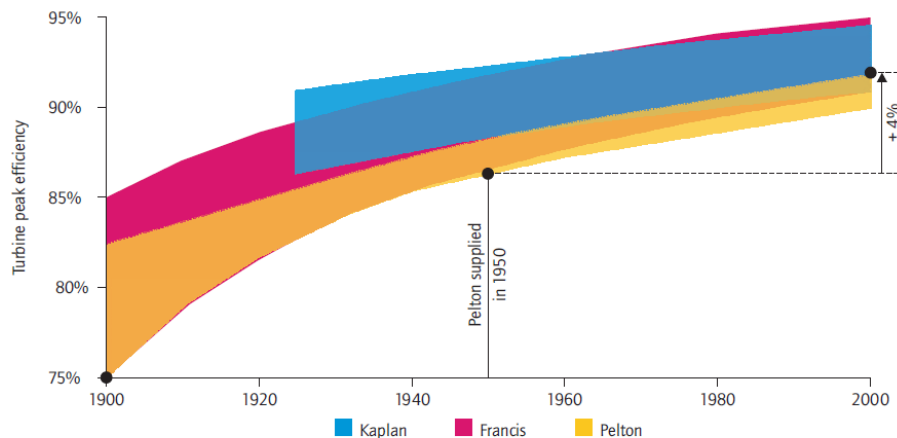
Improvement of hydraulic performance over time (ref. 8)

Some improvements aim directly at reducing the environmental impacts of hydropower by developing
- o Fish-friendly turbines
- o Aerating turbines
- o 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 hydrokinetic turbine in Tabang, East Kalimantan to power a telecommunication tower located at a remote area which is not connected to the grid.
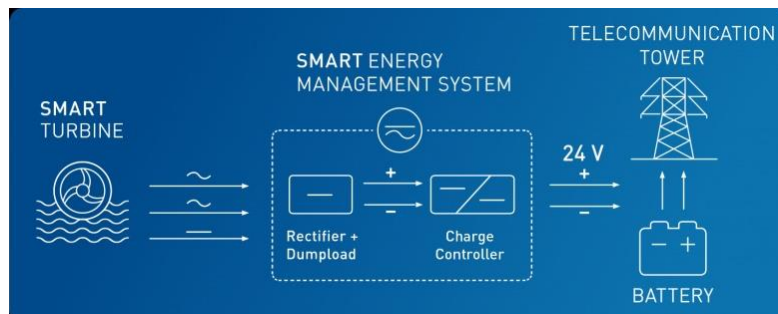
Pico hydropower with hydrokinetic turbine for remote telecommunication towers (ref. 17)

- Bulb (Tubular) turbines:
Nowadays, very low heads can be used for power generation in a way that is economically feasible. Bulb turbines are efficient solutions for low head 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. 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 far 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. In fact, 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.

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Catalogues	**New Catalogue (2020)**		**2.08** (large hydro) **2.29** (small hydro) **2.70** (micro hydro)	**2.00** (large hydro) **2.20** (small hydro) **2.59** (micro hydro)	**1.85** (large hydro) **2.04** (small hydro) **2.40** (micro hydro)
	Existing Catalogue (2017)		2.08 (large hydro) 2.29 (small hydro) 2.70 (micro hydro)	2.08 (large hydro) 2.29 (small hydro) 2.70 (micro hydro)	2.08 (large hydro) 2.29 (small hydro) 2.70 (micro hydro)
Indonesian data	PPA data[1]	2.25 (large hydro) 1.83 (small hydro) 2.13 (mini hydro)			
	ESDM[2]		2.22 (large hydro) 1.48 (mini hydro)		
International data	IRENA	1.63 (large hydro) 2.16 (small hydro)		1.5 (large hydro) 2.5 (small hydro)	
Projection	Learning 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] *ESDM presentation on "KATADATA Shifting Paradigm: Transition towards sustainable energy". Sampe L. Purba (26 August 2020)*

Examples of current projects
Large Scale Hydro Power Plant: Batang Toru Hydro Power Plant (Ref. 21)
The construction of the 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 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 no need for relocation. This project contributes around 15% of North Sumatra's peak load. 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. Total investment cost for this project is 1.68 billion USD. After granted by 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 hydro electric power plant (HEPP) is using the available head from Saguling HEPP (4 x 175 MW) before the water reach Cirata Dam, West Jawa. This mean, the power plant can generate additional electricity from existing cascading system without add pollution to the environment. This plant has capacity of 47 MW and has 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 (m³) 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)
Small hydro Bakal Semarak power plant at Sidikalang, North Sumatera has capacity of 5 MW. The investment cost of this project is estimated of 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 PPA contract for 30 years. This project is scheduled to be online this year. PT Semarak Kita Bersama owns this project.

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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 2019. 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								
	2020	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
				Lower	Upper	Lower	Upper		
Energy/technical data									
Generating capacity for one unit (MWe)	150	150	150	100	2000	100	2000		1,8,10
Generating capacity for total power plant (MWe)	150	150	150	100	2000	100	2000		1,8,10
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	40	40	40	20	95	20	95		2,12
Capacity factor (%), incl. outages	36	36	36	20	95	20	95		2,12
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)	0.1	0.1	0.1	0.0	0.3	0.0	0.3		3
Cold start-up time (hours)	0.1	0.1	0.1	0.0	0.3	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$_2$O (g per GJ fuel)	0	0	0						
Financial data									
Nominal investment (M$/MWe)	2.08	2.00	1.85	1.65	2.25	1.40	2.05	D,E,F	1,4,5,6,9
- of which equipment	30%	30%	30%	20%	50%	20%	50%		11
- of which installation	70%	70%	70%	50%	80%	50%	80%		11
Fixed O&M ($/MWe/year)	37 700	36 200	33 600	28 300	47 100	25 200	42 000	C	1,4,5,6
Variable O&M ($/MWh)	0.65	0.62	0.58	0.49	0.81	0.43	0.72	C	1,5
Start-up costs ($/MWe/start-up)	-	-	-	-	-	-	-		

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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 uncertainty 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.

Technology

Technology	Hydro power plant - Medium system							Note	Ref
	2020	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	50	50	50	10	100	10	100		2
Generating capacity for total power plant (MWe)	50	50	50	20	100	20	100		2
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	80	80	80	50	95	50	95		8,9
Capacity factor (%), incl. outages	76	76	76	50	95	50	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)	0.1	0.1	0.1	0.0	0.3	0.0	0.3		3
Cold start-up time (hours)	0.1	0.1	0.1	0.0	0.3	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$/MWe)	2.29	2.20	2.04	1.4	5.2	1.4	5.2	C,D	4,5,6,7
- of which equipment	30%	30%	30%	20%	50%	20%	50%		7
- of which installation	70%	70%	70%	50%	80%	50%	80%		7
Fixed O&M ($/MWe/year)	41 900	40 200	37 300	22 000	41 900	22 000	41 900		4,5,7
Variable O&M ($/MWh)	0.50	0.48	0.45	0.38	0.63	0.33	0.56	B	1
Start-up costs ($/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 Kimpraswill Makassar".

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

4 Energy and Environmental Economics, 2014, "Capital Cost Review of Power Generation Technologies - Recommendations for WECC's 10- and 20-Year Studies".

5 IEA, World Energy Outlook, 2015.

6 IEA, Projected Costs of Generating Electricity, 2015.

7 ASEAN, 2016, "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, 2016, "Handbook of Energy & Economic Statistics of Indonesia 2016", Ministry of Energy and Mineral Resources, Jakarta, Indonesia.

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Technology

Technology	Hydro power plant - Mini/micro system								
	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	5	5	5	1	10	1	10		1,8
Generating capacity for total power plant (MWe)	5	5	5	1	10	1	10		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	80	80	80	50	95	50	95		2,10
Capacity factor (%), incl. outages	76	76	76	50	95	50	95		2,10
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$_2$O (g per GJ fuel)	0	0	0						
Financial data									
Nominal investment (M$/MWe)	2.70	2.59	2.40	1.2	4.0	1.2	4.0	D,F	1,5,9
- of which equipment	30%	30%	30%	20%	50%	20%	50%		9
- of which installation	70%	70%	70%	50%	80%	50%	80%		9
Fixed O&M ($/MWe/year)	53 000	50 900	47 200	39 800	66 300	35 400	59 000	C	1,5,9
Variable O&M ($/MWh)	0.50	0.48	0.45	0.38	0.63	0.33	0.56	C	1,5
Start-up costs ($/MWe/start-up)	-	-	-	-	-	-	-		

References:

1 PLN, 2017, data provided the System Planning Division at PLN

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 IEA, World Energy Outlook, 2015.

5 Learning curve approach for the development of financial parameters.

6 IEA, Projected Costs of Generating Electricity, 2015.

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".

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

10 MEMR, 2016, "Handbook of Energy & Economic Statistics of Indonesia 2016", Ministry of Energy and Mineral Resources, Jakarta, Indonesia.

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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.

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 in order 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 100-210 Watt-peak pr. m^2 (Wp/m^2). They are sold with a product guarantee of typically two-five years, a power warranty of minimum 25 years and an expected lifetime of more than 30 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- or multi-crystalline 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 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).

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.

In addition to PV modules, a grid connected PV system also includes 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). The PV module itself accounts for less than 50% of the total system costs (and this share is dropping fast), inverters around 5-10%.

Solar PV plants can be installed at the transmission or distribution level (utility-scale PV), or they can satisfy consumption locally (distributed and off-grid PV). Most PV installations are utility-scale nowadays, but the market share of distributed and off-grid PV (rooftop and industrial PV) is rising.

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 structure. Rooftop-mounted systems are small compared to ground-mounted photovoltaic power stations (utility-scale PV) with capacities in the kilowatt range.

Rooftop PV systems can be either on grid or off grid systems. On grid systems are able to use power from the grid when the system could not supply the required power. If the system is well designed, it can supply electricity without using power from the grid. This system can make revenues by feeding excess power to the grid for which PLN pays compensation by using net metering.

Off-grid systems must be equipped with energy storage system, for example through a battery, 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 rooftop is intermittent due to the external factor like cloud cover or others.

Based on RUPTL 2019 – 2028, PLN plans to construct about 908 MW of solar PV power plants within the next ten-year period. About 9% of these solar PV plants are rooftop PV installations. Until the end of 2019, there are already 1,580 PLN customers who have installed rooftop solar PVs. Most of these customers are residential customers. The total installed capacity of rooftop solar PV is 4,930 kWp.

Industrial 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. For comparison, 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 Solar Panels 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.

At the end of 2018, the total installed solar PV capacity in Indonesia is 158.67 MW, including rooftop solar PV. This is a small number compared to huge Indonesia solar energy potential, amounting to about 208 GWe.

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 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 a project for a power plant. The yearly yield of floating PV units can be up over to 10% higher that of ground-mounted PV panels, thanks to a higher irradiance (albedo effect) and a milder and constant temperature not only on PV cells but also on conductors. 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).

The capital cost of Floating PVs is comparable to that of land-based plants. The regular maintenance and cleaning of floating PV modules is eased by the presence of water.

Their capacity can range from several kW to hundreds of MW in size. Masdar, an UAE based company, has signed a power purchase agreement (PPA) with PLN, for the first floating solar photovoltaic (PV) plant in Indonesia. The 145 MW PV plant, which will also be Masdar's first floating solar PV project, will be built on a 225-hectare plot of the 6200-hectare Cirata Reservoir, in the West Java region. This will be the largest capacity of solar PV not only in Indonesia but also in ASEAN countries. It is expected that the plant will come online in 2022/2023.

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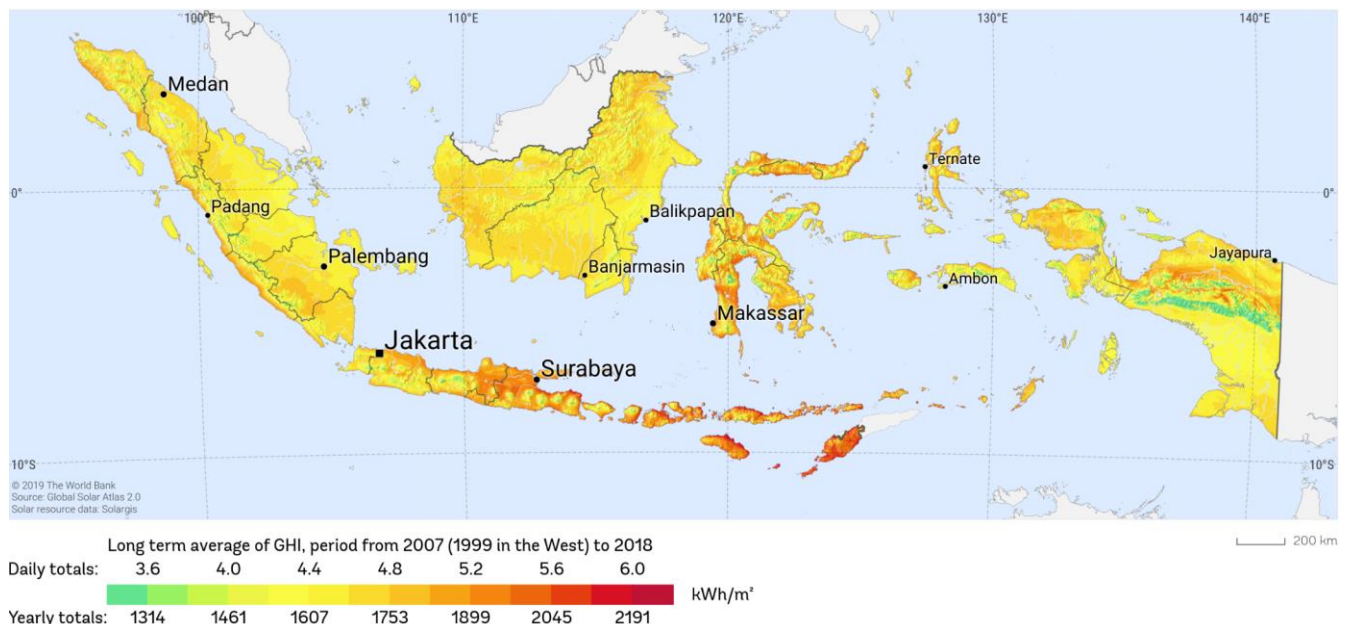
Global Horizontal Irradiation in Indonesia. Source: Global Solar Atlas (Ref. 15)

Due to Indonesia's geographical location very close to the Equator, the solar irradiation is very constant over the year. The graph below shows the average daily irradiation month by month at a location on Northern Java.
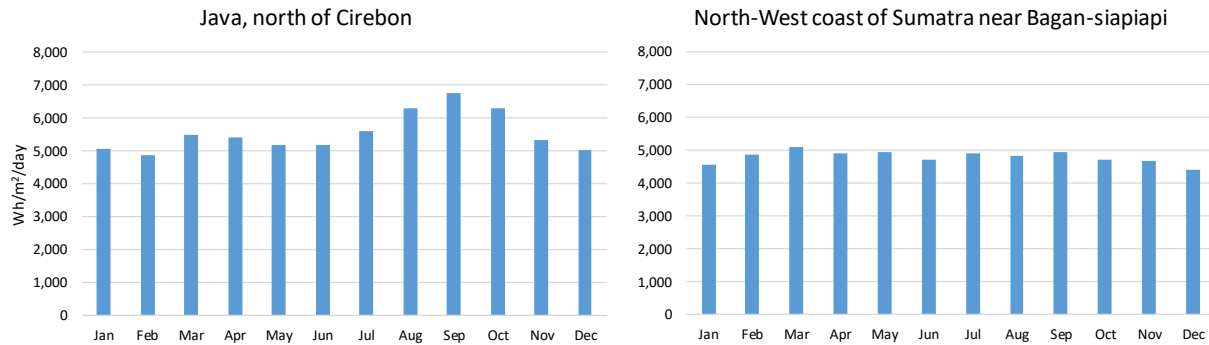
Monthly variation of the average daily irradiation on horizon plane (Wh/m2/day) at two locations: Java, North Coast near Cirebon and North-West coast of Sumatra near Bagansiapiapi. The GHI of the Java site is 2025 kWh per m2 per annum and for the Sumatra location 1755 kWh per m2 per annum. Source: PVGIS European Communities 2001-2012.

In general, solar panels should be tilted in order to capture the irradiation *normally,* that is with sun beams 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.

The 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 capacity of a solar module is not a fixed value, as it depends on the intensity of the irradiation the module receives as well as the module temperature. For practical reasons the module 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. This STC capacity is referred to as the peak capacity P_p [kWp]. Normal operating conditions will often be different 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/m². The plot below shows the land-averaged solar irradiation in Indonesia over a year. Peak values reach 850 W/m², while the irradiation is null for nearly 3500 hours.

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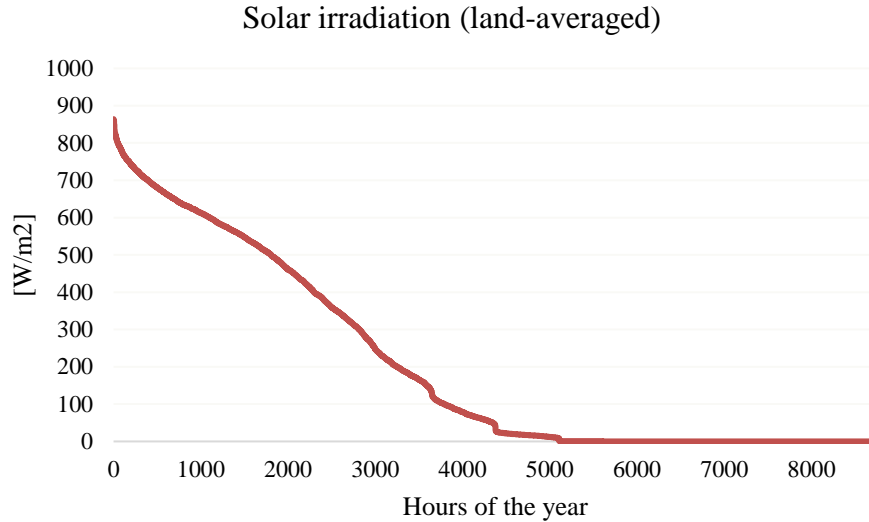
Land-weighted solar irradiation in Indonesia (duration curve). Source: renewables.ninja

In practice, irradiation levels of 1000 W/m² are rarely reached even at the best sites. The graph below shows the global irradiance on a fixed plane (W/m²) during the course of the day in the Java location; for an average daily profile for September - the month with the best solar conditions.
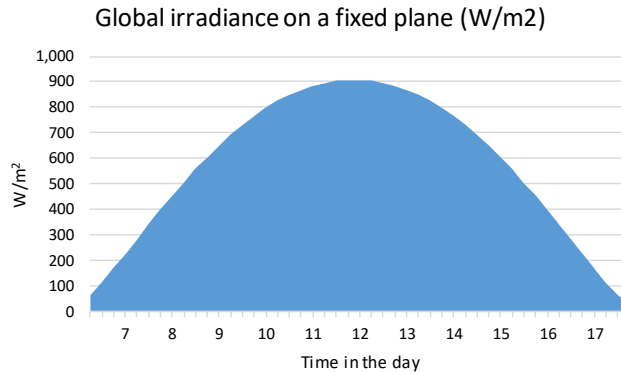
Global irradiance on a fixed plane (W/m²) during the course of the day in the Java, North Coast near Cirebon; average daily profile for September, the month with the best solar conditions. Source: PVGIS © European Communities 2001-2012.

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: with a peak capacity P_p and surface area A can be calculated as follows:

$$E_{PV} = A \cdot GHI \cdot \eta_{pre} \cdot \eta_{nom} \cdot \eta_{rel} \cdot \eta_{sys}$$

where:

A [m^2]　　　　is the modules area

GHI [kWh/m^2]　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.

The yearly output and capacity factor expectations for each Indonesian province, based on data from the Global Solar Atlas *(Ref. 15)* are shown below:

Capacity factor distribution (Quantile 90)
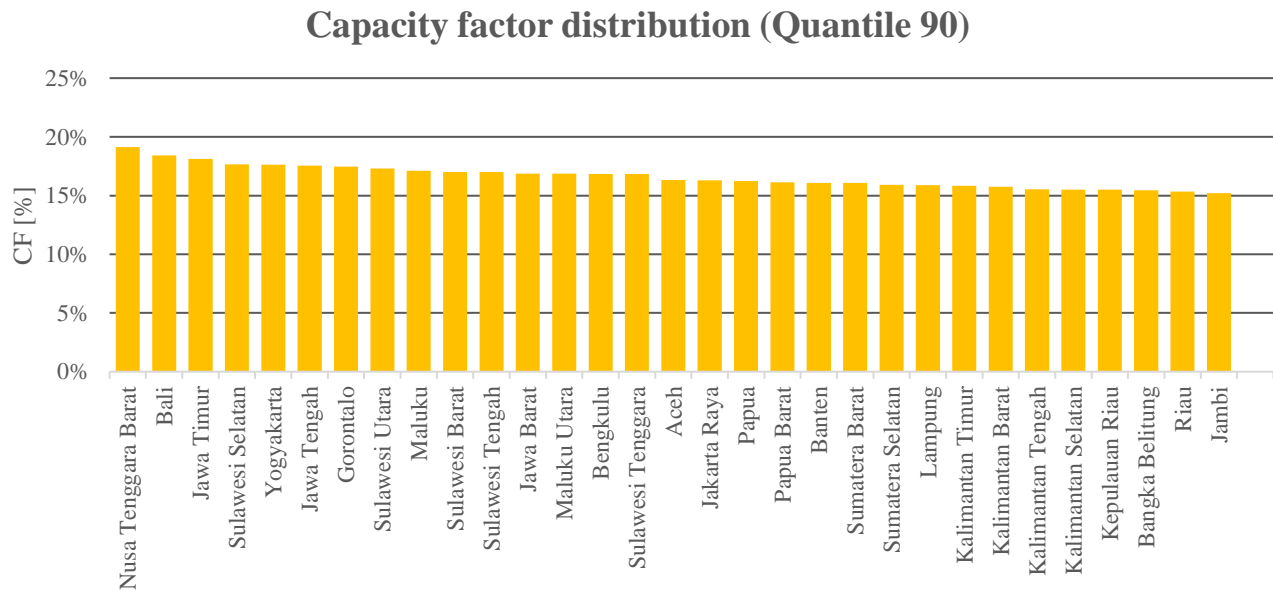
As can be seen, the variation across provinces is not very large, with the annual capacity factor in the range 15-19% for all locations.

	Yearly output [kWh/kW]			Capacity Factor [%]		
	Percentile 10	Median	Percentile 90	Percentile 10	Median	Percentile 90
Aceh	1,248	1,340	1,431	14%	15%	16%
Bali	1,252	1,438	1,613	14%	16%	18%
Bangka Belitung	1,270	1,299	1,354	15%	15%	15%
Banten	1,230	1,340	1,409	14%	15%	16%
Bengkulu	1,230	1,358	1,475	14%	16%	17%
Gorontalo	1,314	1,438	1,529	15%	16%	17%
Jakarta Raya	1,303	1,343	1,427	15%	15%	16%
Jambi	1,245	1,285	1,332	14%	15%	15%
Jawa Barat	1,252	1,387	1,478	14%	16%	17%
Jawa Tengah	1,270	1,460	1,537	15%	17%	18%
Jawa Timur	1,340	1,507	1,588	15%	17%	18%
Kalimantan Barat	1,259	1,332	1,380	14%	15%	16%
Kalimantan Selatan	1,241	1,314	1,358	14%	15%	16%
Kalimantan Tengah	1,270	1,325	1,361	15%	15%	16%
Kalimantan Timur	1,252	1,314	1,387	14%	15%	16%
Kepulauan Riau	1,263	1,318	1,358	14%	15%	16%
Lampung	1,307	1,343	1,391	15%	15%	16%
Maluku Utara	1,281	1,391	1,478	15%	16%	17%
Maluku	1,208	1,321	1,500	14%	15%	17%
Nusa Tenggara Barat	1,383	1,551	1,675	16%	18%	19%
Nusa Tenggara Timur	1,460	1,610	1,705	17%	18%	19%
Papua Barat	1,234	1,340	1,413	14%	15%	16%
Papua	1,164	1,303	1,424	13%	15%	16%
Riau	1,259	1,292	1,343	14%	15%	15%
Sulawesi Barat	1,205	1,365	1,489	14%	16%	17%
Sulawesi Selatan	1,259	1,424	1,548	14%	16%	18%
Sulawesi Tengah	1,205	1,369	1,489	14%	16%	17%
Sulawesi Tenggara	1,292	1,398	1,475	15%	16%	17%
Sulawesi Utara	1,278	1,402	1,515	15%	16%	17%
Sumatera Barat	1,212	1,310	1,409	14%	15%	16%
Sumatera Selatan	1,285	1,329	1,394	15%	15%	16%
Yogyakarta	1,405	1,478	1,544	16%	17%	18%

Wear and degradation

In general, a PV installation is very robust and only requires a minimum of component replacement over the course of 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 (ref. 13). Failures in the PV system is typicalky related to soldering, cell crack or hot spots, yellowing or delamination of the encapsulant foil, junction box failures, loose cables, hailstorm and lightning (ref. 14).

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. A typical value for commercially available PV modules today is 15 – 19%, with high-end products already above 20%, when measured at standard test conditions. 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 6.25 m^2 by today's standard PV modules.

Ground mounted modules may be located very close to each other in Indonesia, since shadow impacts is not an issue. The ground mounted 1 MW PV plant at Cirata occupies 8.65 m^2 per kWp (1040 kWp using 0.9 Hectare area). The newly built Likupa Solar PV at North Sulawesi has a capacity of 21 MW and land coverage of 29 hectares. This means that Likupa PV plant takes 1.38 ha land for 1 MW capacity. Floating PV needs different area requirement. The planned floating Solar PV Cirata would have area coverage of 225 ha. Since the capacity of new Cirata is 145 MW then every 1 MW needs reservoir surface area of 1.55 hectares. Bali Barat dan Bali Timur Solar PV take 1.2 hectares per MW.

Typical capacities

Typical capacities for PV systems are available from Watt to GW sizes. But in this context, it 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 200-400 Wp.

Rooftop PV systems on Indonesia residential buildings typically have a capacity of about 1 to 10 kW, while those mounted on commercial or industrial buildings could reach 100 kW or more. Commercial or Industrial PV systems are typically installed on industries, offices or public buildings, and range typically from 50 to 500 kW in size. Such systems are often designed to the available roof area and for a high self-consumption. Utility scale systems or PV power 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, but the most currently installed PV systems will 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 and along with other issues.

Advantages/disadvantages

Advantages:

- PV does not use any fuel or other consumable.
- 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 highest.

- 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, with the exception of 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 are of no commercial use (landfills, areas of restricted access or chemically polluted areas).
- PV systems integrated in 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 and low capacity factor.
- Only produce power when there is sun, meaning necessary for regulation power or storage.
- 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 basically follows the daily and yearly variations in solar irradiation.
- Materials abundancy (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, but 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.

Employment
Most parts from solar PV can be produced in Indonesia. Currently there are twelve PV panel producers in Indonesia, including PT LEN and Hanover Solar. PT. LEN is manufacturing PV modules for the Indonesian market with production capacity of 71 MWp. PT LEN employs about 521 people. PT LEN has five business units. Production of PV modules is one of its five business units. Hanover Solar produce all parts to PV cells on their factory on Batam Island, Indonesia, and have 300 full time employees, producing annually 200 MW solar PV for exporting purposes. The other PV companies have less production capacity of about 10 – 30 MWp per year.
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.
Institute for Essential Services Reform (IESR) of Indonesia has proposed a program called "1 GWp Solar PV for Households". It is expected that the program would create about 78,000 jobs, direct and indirect.

Research and development
The PV technology is already commercial but is still constantly improved in efficiency and decreased in cost (category 3). A trend in research and development (R&D) activities reflects a change of focus from manufacturing and scale-up issues (2005-2010) and cost reduction topics (2010-2013) to implementation of high efficiency solutions and documentation of lifetime/durability issues (2013-). R&D is primarily conducted in countries where the manufacturing also takes place, such as Germany, China, USA, Taiwan and Japan.

Investment cost estimation
The cost of solar PV projects has decreased significantly both in Indonesia and internationally. The reported investment cost of the Indonesian solar PV power generation as follows:
- Likupang Solar PV at North Sulawesi: 1.39 million USD/MWp
- Bali Barat Solar PV at Bali: 0.89 million USD/MWp
- Bali Timur Solar PV at Bali: 0.85 million USD/MWp
- Cirata Floating Solar PV at West Jawa: 0.89 million USD/MWp

The cost of rooftop solar PV in Indonesia is typically higher than ground mounted PV. Based on several providers or merchants, the investment cost of rooftop solar PV ranges from 1.07 to 1.72 million USD/MWp depending on the capacity installed from 1 kWp to 5.5 kWp.

Module prices can be observed at the PV Insights website. By September 2020, the average price of polysilicon solar modules was 0.167 USD/Watt, with prices as low as 0.15 USD/Watt. The price of PV module in Indonesia is about 0.40 – 0.47 USD/Watt (ref. 8).

The price difference between international levels and the Indonesian context can be expected to diminish as the experience with installation of PV plants in Indonesia increases.

The prices of solar PV modules have declined very significantly historically, a reduction in the order of 23% has been achieved each time the cumulative production has been doubled.

For this assessment is proposed applying a learning rate of 20% for approx. two-thirds of the solar PV system price, which relates to the module and the inverter. This is slightly lower than the historical observed values, but still a high learning rate compared to other technologies. Using a learning rate of 20% for the module and a future deployment of solar PV capacity as projected by the IEA, we expect PV module costs to drop by around 20-30% between 2020 and 2030 and between 40 and 50% between 2020 and 2050 (ref 5).

For the remaining one third of costs, a more moderate projection development is used, with costs falling by 1% per year until 2020, by 0.75% p.a. between 2020 and 2030 and then by 0.5% p.a.

This leads to the cost projection, presented in the following table, for large-scale solar PV systems, for the international price level as well as the expected level for Indonesia. Historically, the IEA has systematically underestimated the global deployment of PV capacity.

Projected investment cost of utility-scale solar PV systems.

Mill. USD/MWp	2020	2030	2050
International price	0.67	0.53	0.41
Indonesian price	0.79	0.56	0.41

The Levelised Cost of Electricity from solar PV in Indonesia is also affected by local content rules, import duties and taxes on foreign PV modules. The figure below reports how the LCOE is affected by these levies. When using Chinese modules, investment costs would rise by ~10%, but the overall cost of electricity would remain lower than when starting from local modules.

Impact of import duties on the LCOE of PV generation. Source: Institute for Essential Services Reform.

The investment cost of a solar PV project is therefore subject to uncertainty, especially because the technology is capital intensive. The size of the project also contributes to the specific cost, as small projects tend to require higher investments. The table below summarizes investment cost figures from relevant sources, along with the recommended values (ground-mounted PV). The solar PV industry has notched up the competitiveness of manufacturing processes in recent years, driven by a considerable R&D spending on cell materials and modules 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. As of 2020, there exists a cost gap between locally engineered and imported modules. This catalogue expects this gap to narrow with time, leading to a convergence with international prices in the long run.

The investment costs of other types of PV plants (industrial, rooftop, floating – not reported here) are higher than those of ground-mounted PV due to economy of scale. Rooftop PV is considered to cost roughly 50-75% more than a utility-scale plant.

In November 2020, Indonesia Power, a subsidiary of state-owned electricity utility PLN, launched the bidding process for the procurement of equity partners on 4 solar projects. The lowest offer received at 3.7 cUSD/kWh is 37% lower than the PPA projects signed earlier in 2020 for Cirata and Bali (5.8-5,9 cUSD/kWh), signalling a fast cost drop also in Indonesia (ref. 13).

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Catalogues	**New Catalogue (2020)**		**0.79**	**0.56**	**0.41**
	Existing Catalogue (2017)		0.83	0.61	0.45
Indonesia data	PPA data[1]	1.40	0.88		
	Feed-in Tariff, own calculation[2]		0.71		
	ESDM[3]		0.98		
	IRENA[4] (Indonesian data for 2019)	0.85			
	Institute for Essential Service Reform (Indonesia)[5]	0.95*			
International data	IEA WEO 2019 (average of India and China)	0.84			0.46 *(2040)*
	Danish technology catalogue		0.48	0.34	0.27
	NREL ATB	1.17	0.99	0.61	0.50
	Lazard	1.00			
	UK Government (DECC)			0.58	0.45 (2040)
Projection	Learning curve – cost trend [%]	-	100%	71%	52%

[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). Values for 2020 refers to average of PPA signed in 2020 for projects in Bali and Cirata with COD 2021-2023.*

[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).*

[5] *IESR."Levelized cost of electricity in Indonesia" (2019). Range for solar PV CAPEX 0.7-1.2 MUSD/MW.*

Examples of current projects
Floating Solar PV: Cirata Floating Solar PV. (Ref. 8)
The Cirata floating PV project is a monumental renewable energy project for Indonesia, and the biggest floating PV in South East Asia. It will improve the capability of the Jawa-Bali power system and also increase the renewable energy mix in Indonesia. The planned 145 MW floating PV plant will be built on a 225 ha section of the Cirata Reservoir in West Java. This is a 129 million USD project with support from Abu Dhabi-based renewables firm Masdar. After signing the PPA with PLN, the company agreed to sell the electricity produced at 5.8 US cents/kWh. It is expected that the project should has finished and start to produce electricity in 2022 or 2023. It is planned that the construction will begin next year.

Ground mounted Solar PV: Bali Barat and Timur Solar PV. (Ref. 9)
Bali Barat and Bali Timur Solar PV are located in Bali with total installed capacity of 50 MW, 25 MW each. PLN will announce the company which will develop the project soon. It is estimated that the total investment cost is 43.5 million USD. PLN expect to buy the electricity at 5.9 US cents/kWh because Bali is part of Jamali (Jawa Madura and Bali) grid system. Therefore, the electricity price of Bali Barat and Bali Timur should be competitive with price of electricity generated by coal fired power plants that dominate the Jamali system. These project are expected on line in 2022.

Another ground mounted PV that is already operational since 2019 is Likupang Solar PV. With installed capacity of 21 MW, it is the largest solar PV capacity in Indonesia at the moment. It is located at Likupang in North Sulawesi. It takes one and a half year to finish the project. Vena Energy, Singapore based company, owns this project. According to the company, they invested about 29.2 million USD to build the Likupang solar PV. It covers about 29 hectares of land.

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

Commercial Rooftop Solar PV: PT Coca Cola Amatil Indonesia Rooftop PV. (Ref. 11)
The interest of Rooftop PV (on-grid) begins to grow in Indonesia. There were already 1,580 installations of rooftop PV until December 2019. Interest in the installation has increased among household, business and commercial customers, especially after the revision of MEMR Minister Ordinance No. 49/2018. PT Coca Cola of Indonesia has decided to build 7.13 MW rooftop PV at their factory in Bekasi, West Jawa. It will be the first largest rooftop PV in South East Asia, the second largest in Asia Pacific and the fourth largest in the world. 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.
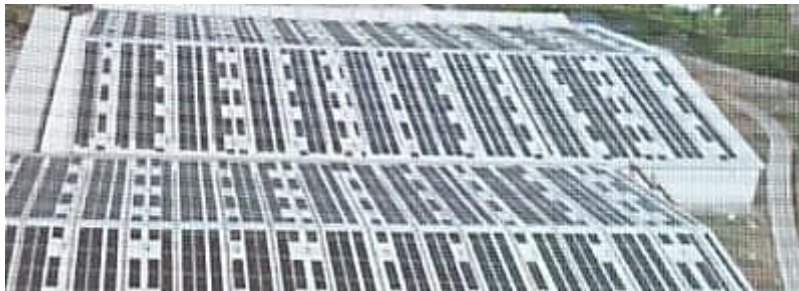
PT Coca Cola Amatil Rooftop PV at Bekasi, West Jawa (Ref. 11)

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 capacity of 2.919 MW. This rooftop PV can generate electricity for 4 gigawatt hours (GWh) per year while reducing 3,340 tons of carbon emissions per year. Currently it is the largest rooftop PV in Indonesia. Actually for Aqua Danone, this is the second rooftop PV that was installed in their factory roof. The first one at Cikarang, West Jawa with installed capacity of 770 kWp which can generate 1 GWh of electricity per year, as well as reducing carbon emissions by 825 tons per year in 2017.

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

In order to avoid or minimize land disputes, Indonesia has a plan to develop Solar PV projects on areas of abandoned coal and tin mining in Bangka Belitung and Kalimantan islands. 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

Following the success of power purchase agreement (PPA) between PLN and Masdar of United Arab Emirates in delivering electricity from 145 MW of Floating Solar PV at Cirata dam reservoir, Indonesia set up another plan to install 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

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 used:

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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 2019. 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				Utility-scale Solar PV					
	2020	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data				**Lower**	**Upper**	**Lower**	**Upper**		
Generating capacity a typical power plant (MWe)	10	20	50					C	1
Electricity efficiency, net (%), name plate	-	-	-					A	
Electricity efficiency, net (%), annual average	-	-	-					A	
Forced outage (%)	-	-	-						
Planned outage (weeks per year)	-	-	-						
Technical lifetime (years)	35	40	40	25	40	35	45		1,6
Construction time (years)	0.5	0.5	0.5	0.5	1.5	0.25	1		1
Space requirement (1000 m^2/MWp)	14	14	14	13	18	13	18		6
Additional data for non thermal plants									
Capacity factor (%), theoretical	19	22	22	17	23	17	23		1,2
Capacity factor (%), incl. outages	19	22	22	17	23	17	23		1,2
Ramping configurations									
Ramping (% per minute)	-	-	-	-	-	-	-	B	
Minimum load (% of full load)	-	-	-	-	-	-	-	B	
Warm start-up time (hours)	-	-	-	-	-	-	-	B	
Cold start-up time (hours)	-	-	-	-	-	-	-	B	
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$_2$O (g per GJ fuel)	0	0	0						
Financial data									
Nominal investment (M$/MWe)	0.79	0.56	0.41	0.70	1.20	0.31	0.71	D,R,S	1,3,4
- of which equipment	44%	39%	35%						
- of which installation	56%	61%	65%						
Fixed O&M ($/MWe/year)	14 400	10 000	8 000	10 800	18 000	5 300	10 700	E,Q	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)	1 800	1 800	1 800					F	8
DC/AC sizing factor (Wp/W)	1.10	1.10	1.10					G	
Transposition Factor for fixed tilt system	1.01	1.01	1.01					H	8
Performance ratio [-]	0.86	0.95	0.97					I	6
PV module conversion efficiency (%)	20.5%	23.0%	26.0%						6
Inverter lifetime (years)	15	15	15						6
Output									
Full load hours (kWh/kW)	1 700	1 950	1 950					J, L	
Peak power full load hours (kWh/kWp)	1 550	1 750	1 750					K, L	
Financial data									
PV module & inverter cost ($/Wp)	0.32	0.20	0.13						7
Balance Of Plant cost ($/Wp)	0.40	0.31	0.24						7
Specific investment, total system ($/Wp)	0.72	0.51	0.37					M	5,6,9
Specific investment, total system (M$/MW)	0.79	0.56	0.41					P	

Technology

Technology	Industrial PV - Large scale grid connected								
	2020	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
				Lower	**Upper**	**Lower**	**Upper**		
Energy/technical data									
Generating capacity for total power plant (kWe)	100	100	100					C	6
Electricity efficiency, net (%), name plate	-	-	-					A	
Electricity efficiency, net (%), annual average	-	-	-					A	
Forced outage (%)	-	-	-						
Planned outage (weeks per year)	-	-	-						
Technical lifetime (years)	25	25	25	25	40	35	45		1,6
Construction time (years)	1.0	0.5	0.5	0.5	1.5	0.25	1		1
Space requirement (1000 m^2/MWe)	9	8	7	13	18	13	18		
Additional data for non thermal plants									
Capacity factor (%), theoretical	17.7	19.4	19.4	14	22	16	23		1,2
Capacity factor (%), incl. outages	17.7	19.4	19.4	14	22	16	23		1,2
Ramping configurations									
Ramping (% per minute)	-	-	-	-	-	-	-	B	
Minimum load (% of full load)	-	-	-	-	-	-	-	B	
Warm start-up time (hours)	-	-	-	-	-	-	-	B	
Cold start-up time (hours)	-	-	-	-	-	-	-	B	
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$_2$O (g per GJ fuel)	0	0	0						
Financial data									
Nominal investment (M$/MWe)	1.19	0.84	0.62	1.05	1.80	0.47	1.07	D,R,S	1,3,4
- of which equipment	44%	36%	34%						
- of which installation	56%	64%	66%						
Fixed O&M ($/MWe/year)	14 400	10 000	8 000	10 800	18 000	5 300	10 700	E,Q	5,6
Variable O&M ($/MWh)	0	0	0	0	0	0	0		
Start-up costs ($/MWe/start-up)	0	0	0	0	0	0	0		
Technology specific data									
Global horizontal irradiance (kWh/m2/y)	1 600	1 600	1 600					F	8
DC/AC sizing factor (Wp/W)	1.10	1.10	1.10					G	
Transposition Factor for fixed tilt system	1.01	1.01	1.01					H	8
Performance ratio	0.86	0.95	0.97					I	6
PV module conversion efficiency (%)	21%	23%	26%						6
Inverter lifetime (years)	15	15	15						6
Output									
Full load hours (kWh/kW)	1 550	1 700	1 700					J, L	
Peak power full load hours (kWh/kWp)	1 400	1 550	1 550					K, L	
Financial data									
PV module & inverter cost ($/Wp)	0.48	0.27	0.19						7
Balance Of Plant cost ($/Wp)	0.60	0.47	0.37						7
Specific investment, total system ($/Wp)	1.08	0.77	0.56					M	5,6,9
Specific investment, total system (million $/MW)	1.19	0.84	0.62					P	

Technology

Technology	Rooftop PV grid connected								
	2020	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data				**Lower**	**Upper**	**Lower**	**Upper**		
Generating capacity for total power plant (kW)	5	5	5					C	1,6
Electricity efficiency, net (%), name plate	-	-	-					A	
Electricity efficiency, net (%), annual average	-	-	-					A	
Forced outage (%)	-	-	-						
Planned outage (weeks per year)	-	-	-						
Technical lifetime (years)	35	40	40	25	40	35	45		1,6
Construction time (years)	0.1	0.1	0.1	0.1	0.5	0.1	0.5		1
Space requirement (m^2/kW)	7	6	5	13	18	13	18		1
Additional data for non thermal plants									
Capacity factor (%), theoretical	17.7	19.4	19.4	17	23	17	23		1,2
Capacity factor (%), incl. outages	17.7	19.4	19.4	17	23	17	23		1,2
Ramping configurations									
Ramping (% per minute)	-	-	-	-	-	-	-	B	
Minimum load (% of full load)	-	-	-	-	-	-	-	B	
Warm start-up time (hours)	-	-	-	-	-	-	-	B	
Cold start-up time (hours)	-	-	-	-	-	-	-	B	
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$_2$O (g per GJ fuel)	0	0	0						
Financial data									
Nominal investment (M$/MWe)	1.32	0.94	0.69	1.15	2.00	0.50	1.20	D,R,S	1,3,4
- of which equipment	44%	39%	35%						
- of which installation	56%	61%	65%						
Fixed O&M ($/MWe/year)	14 400	10 000	8 000	10 800	18 000	5 300	10 700	E,Q	5,6
Variable O&M ($/MWh)	0	0	0	0	0	0	0		
Start-up costs ($/MWe/start-up)	0	0	0	0	0	0	0		
Technology specific data									
Global horizontal irradiance (kWh/m2/y)	1 600	1 600	1 600					F	8
DC/AC sizing factor (Wp/W)	1.10	1.10	1.10					G	
Transposition Factor for fixed tilt system	1.01	1.01	1.01					H	8
Performance ratio	0.86	0.95	0.97					I	6
PV module conversion efficiency (%)	21%	23%	26%						6
Inverter lifetime (years)	15	15	15						6
Output									
Full load hours (kWh/kW)	1 550	1 700	1 700					J, L	
Peak power full load hours (kWh/kWp)	1 400	1 550	1 550					K, L	
Financial data									
PV module & inverter cost ($/Wp)	0.53	0.33	0.22						7
Balance Of Plant cost ($/Wp)	0.67	0.52	0.41						7
Specific investment, total system ($/Wp)	1.20	0.85	0.62					M	5,6,9
Specific investment, total system (million $/MW)	1.32	0.94	0.69					P	

Technology

Technology	Floating PV - Large scale grid connected							Note	Ref
	2020	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for total power plant (MWe)	10	10	10					C	
Electricity efficiency, net (%), name plate	-	-	-					A	
Electricity efficiency, net (%), annual average	-	-	-					A	
Forced outage (%)	-	-	-						
Planned outage (weeks per year)	-	-	-						
Technical lifetime (years)	25	25	25	25	40	35	45		1,6
Construction time (years)	1.0	0.5	0.5	0.5	1.5	0.25	1		1
Space requirement (1000 m^2/MWe)	14	12	12	13	18	13	18		
Additional data for non thermal plants									
Capacity factor (%), theoretical	21.0	24.0	24.0	14	22	16	23		1,2
Capacity factor (%), incl. outages	21.0	24.0	24.0	14	22	16	23		1,2
Ramping configurations									
Ramping (% per minute)	-	-	-	-	-	-	-	B	
Minimum load (% of full load)	-	-	-	-	-	-	-	B	
Warm start-up time (hours)	-	-	-	-	-	-	-	B	
Cold start-up time (hours)	-	-	-	-	-	-	-	B	
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$_2$O (g per GJ fuel)	0	0	0						
Financial data									
Nominal investment (M$/MWe)	0.89	0.66	0.48	0.83	1.43	0.37	0.84	D,R,S	1,3,4
- of which equipment	51%	50%	47%						
- of which installation	49%	50%	53%						
Fixed O&M ($/MWe/year)	16 200	13 500	11 300	12 200	20 300	8 500	14 100	E,Q	5,6
Variable O&M ($/MWh)	0	0	0	0	0	0	0		
Start-up costs ($/MWe/start-up)	0	0	0	0	0	0	0		
Technology specific data									
Global horizontal irradiance (kWh/m2/y)	1 800	1 800	1 800					F	8
DC/AC sizing factor (Wp/W)	1.10	1.10	1.10					G	
Transposition Factor for fixed tilt system	1.01	1.01	1.01					H	8
Performance ratio	0.86	0.95	0.97					I	6
PV module conversion efficiency (%)	20.5%	23.0%	26.0%						6
Inverter lifetime (years)	15	15	15						6
Output									
Full load hours (kWh/kW)	1 700	1 950	1 950					J, L	
Peak power full load hours (kWh/kWp)	1 550	1 750	1 750					K, L	
Financial data									
PV module & inverter cost ($/Wp)	0.41	0.30	0.21						7
Balance Of Plant cost ($/Wp)	0.40	0.30	0.23						7
Specific investment, total system ($/Wp)	0.81	0.60	0.44					M	5,6,9
Specific investment, total system (million $/MW)	0.89	0.66	0.48					P	

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1 PLN, 2017, data provided the System Planning Division at PLN

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

3 IEA, World Energy Outlook, 2019.

4 Learning curve approach for the development of financial parameters.

5 Cirata 1 MW Solar PV O&M and Financial Perspective, Sharing Experience. PJB.

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

7 Permasalahan penetrasi solar pv pada sistem grid nasional, Dewan Energi Nasional, Juni 2017 PT Len Industri (Persero)

8 PVGIS © Europeen Communitees 2001-2012.

9 Learning curve based forecast of technology costs. Ea Energy Analyses, 2020

Notes:

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

B The production 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.

C Listed as MWe. The MWp will be around 10% higher.

D Assumptions described in the section "Assumptions and perspectives for further development"

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

F The global horizontal irradiation is a measure of the energy resource potential available and depends on the exact geographical location. 1800 kWh/m2 corresponds to a good location in Indonesia, in the top 20% percentile of the best solar sites.

G The DC/AC shown in the table equals module peak capacity divided by plant capacity. 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 number of full load hours is calculated based on the other values in the table. The formula is: Full load hours = Global horizontal irradiance * transposition factor * performance ratio.

K Also known as the specific yearly energy production (kWh/kWp) of the PV modules. This value is calculated from this formula: Peak power full load hours = 1046 * transposition factor * (1-incident angle modifier loss) * (1-PV system losses etc.) * (1-inverter loss) * (1-AC grid loss).

L Capacity factor = Full load hours / 8760.

M Current international market prices for utility scale PV systems have been estimated based on interviews with Danish developers and an assesment of the prices from Danish and Germany tenders for PV capacity in 2016 and the beginning of 2017. The forecasted internatinal price is based on estimated learning rates for the module and invester (20 % learning rate) and balance of plant (10 % learning rate) and a projection of the cumulated PV capacity based on the IEA's 450 ppm scenario. The share that the PV module and the invester accounts for decreases over time as the result of the higher learning rate compared to the balance of plant. Indonesian prices are assumed to be somewhat higher in the first years thereafter approaching gradually the international level.

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 and land-lease. Annual O&M is estimated to be 2 % of investment cost per MWp.

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

S For 2020, uncertainty ranges are based on cost spans of various sources. For 2050, we combine the base uncertainty in 2020 with an additional uncertainty span based on learning rates variying between 17.5-22.5% and capacity deployment from Stated Policies and Sustainable Development scenarios separately.

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

This catalogue treats only onshore wind turbines, which are currently the most attractive option for Indonesia. The typical large onshore 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.

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.
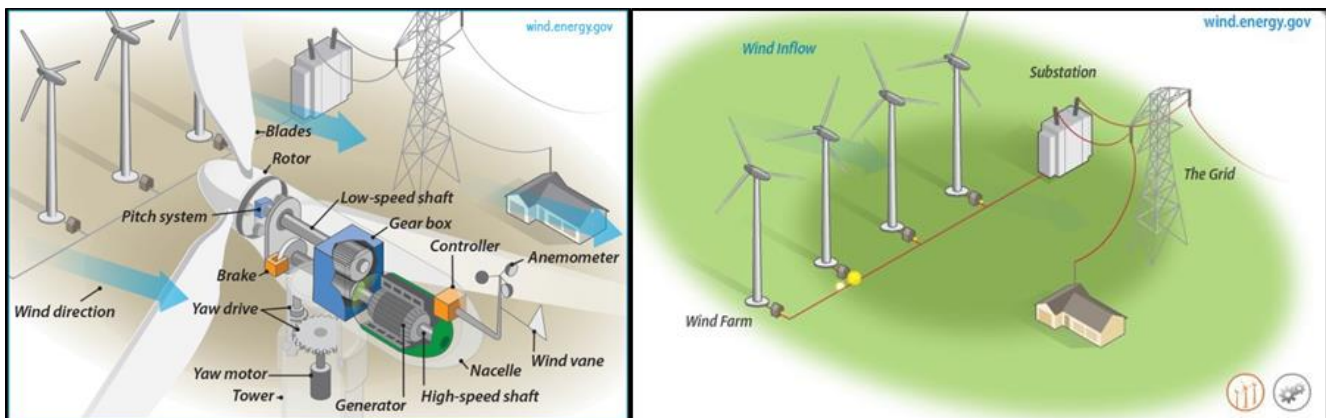
General turbine technology and electrical system

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/m².

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 shows the wind resource distribution in Indonesia. The best sites in the country are found in the South and are endowed with a low wind resource, as specified by the IEC.
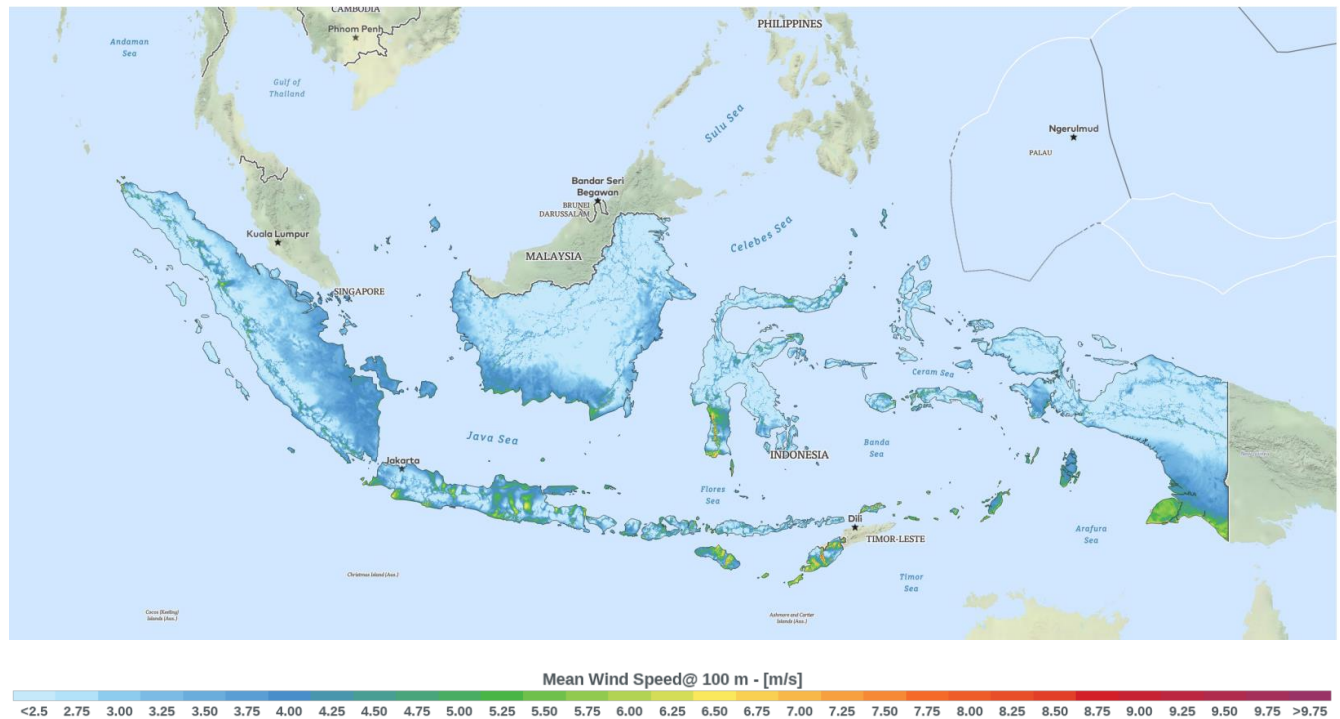
Wind speed at 100m above ground in Indonesia. Source: Global Wind Atlas.

The turbine design differs consistently depending on the type of wind resource. In low-wind (LW) sites, turbines are generally taller and sweep a larger area. In other terms, they are characterized by taller hubs and a smaller specific power. 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:

$$P = 0.5 \cdot \rho \cdot A \cdot v^3$$

ρ 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. Hoverer, the offshore wind resource is better, and possible onshore sites are limited.
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).
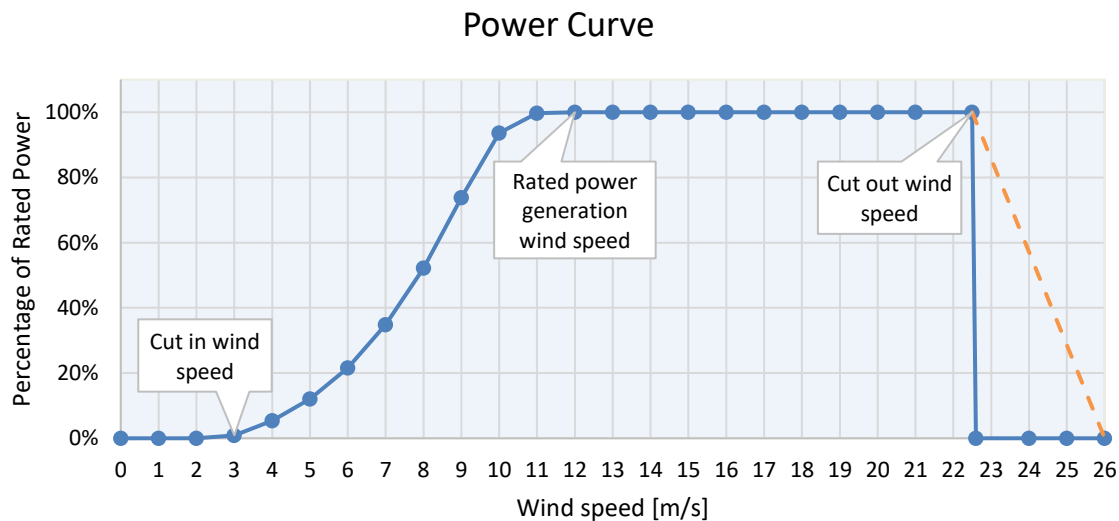
Power curve for a typical wind turbine.

Output
The output is electricity.

Generally speaking, 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 onshore turbine located at these good sites in Indonesia will be in the range of 35% corresponding to around 3055 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.

Estimated duration curves for typical onshore turbine at different locations

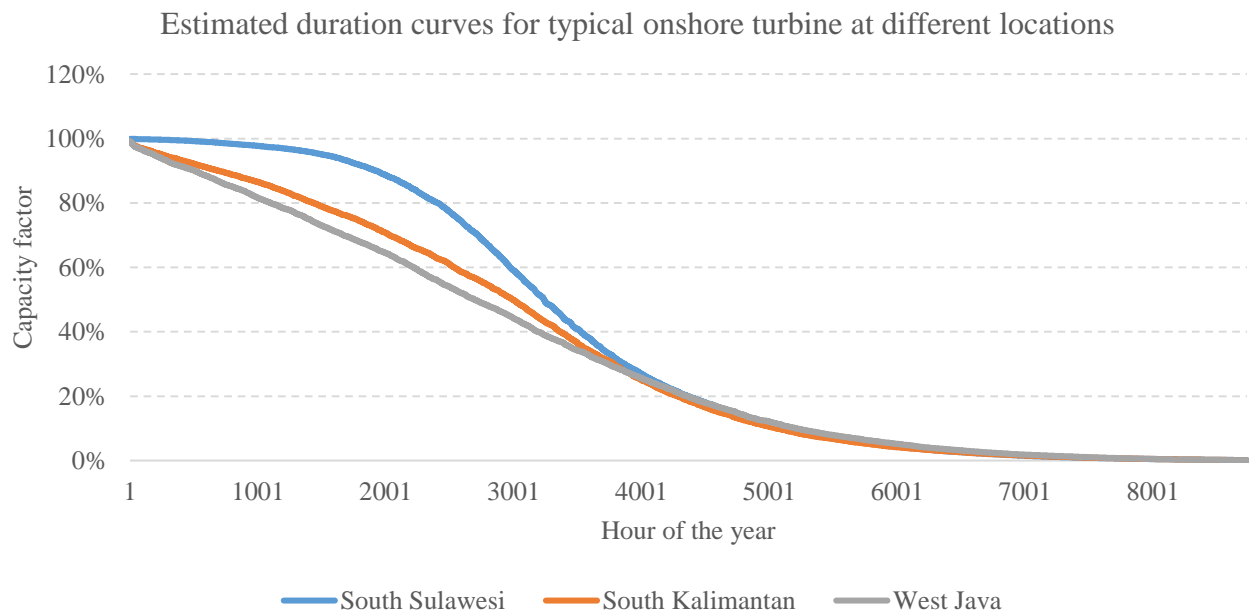*Onshore Duration Curves for different Indonesian locations based on the Indonesian wind resource map at 100 m (ref. 1) and on the power curve for a low wind speed turbine (calculations are based on the power curve of a Vestas V126, 3.45 MW).*

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 2 to 6 MW and typical offshore installations are in the range of 3-6 MW. However, turbine capacities of offshore wind turbines are expected to increase in the near future, and current projects in UK are already in 8 MW range (ref. 17). As illustrated before, the nameplate capacity strongly depends on the

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 (see above).
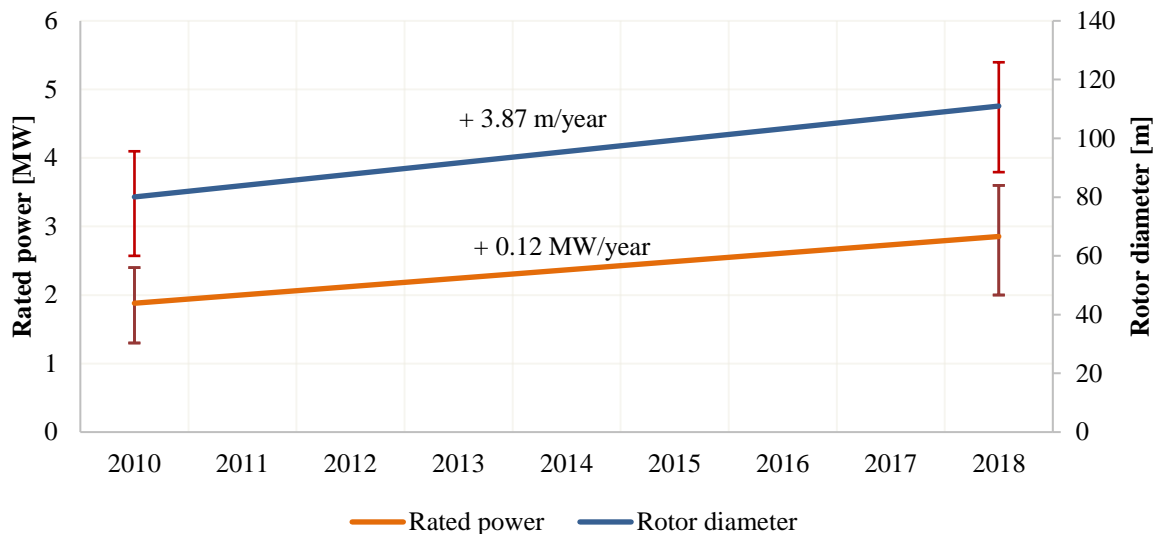
Evolution of rotor diameter and rated power in 2010-18 (world figures). Source: IRENA's Renewable Power Generation Costs in 2019.

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).

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 - in many cases - also up, provided that the turbine is 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. This mode of operation is

technically possible and in many countries turbines are required to have this feature. However, it is rarely used, since 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 may require clearing of forest areas.
  - High population density in on e.g. Java leaves little room for wind farms.
- 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 a 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

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 and solvents from surface coatings).

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 and 150 workers at the operational state, 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. Figures almost double when considering indirect employment.

Service providers include transportation of equipment, engineering and construction, maintenance, research and consultancy activities, financial services.
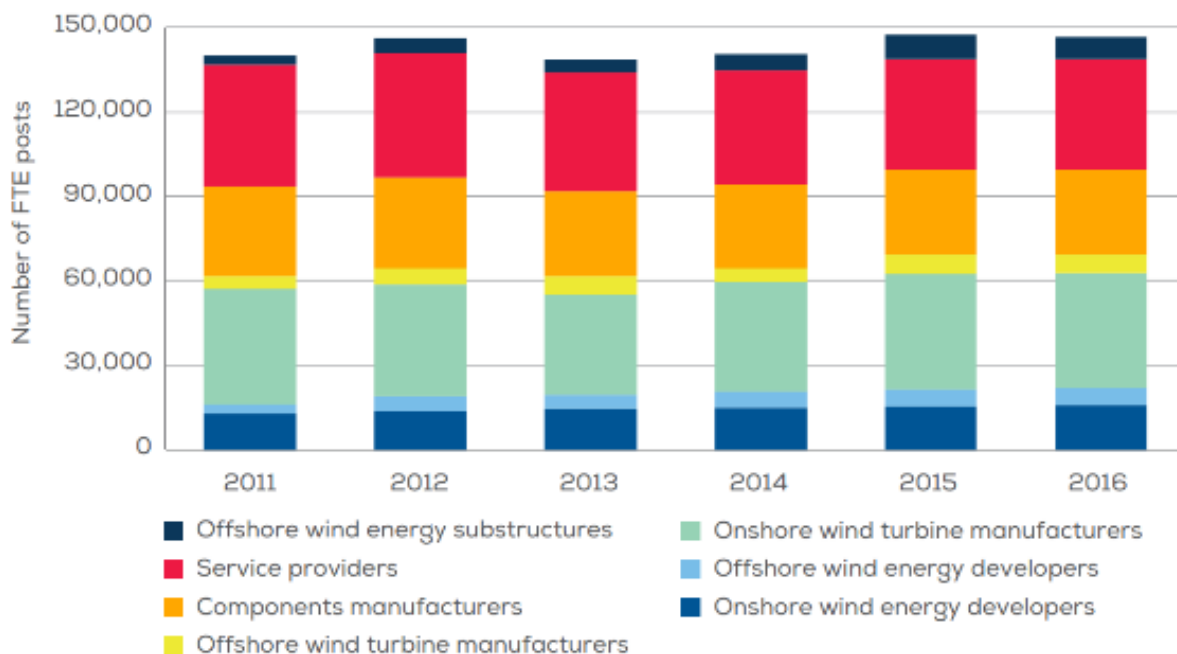
Direct employment (Full Time Employment) by company type related to the wind industry in Europe (ref. 6).

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
  - 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
The experience with wind power deployment in Indonesia is extremely 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 2020.

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. The annual specific production (capacity factor/full load hours) is expected to continue to increase. The increase in production is mainly expected to be 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 1.6% increase in capacity factor by 2030 compared to 2020 and 4.8% improvement by 2050.

The predictions of cost reductions are made using the learning curve principle (see the Appendix). 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. 15% by 2030 and approx. 28% by 2050.

K p x g u v o g p v "₄e₂ ₄;0¥u "		4 2 3 :	4 2 4 2	4 2 5 2	4 2 7 2
Catalogues	**New Catalogue (2020)**		**1.50**	**1.28**	**1.08**
	Existing Catalogue (2017)		1.56	1.36	1.10
Indonesia data	PPA data[1]	1.66			
	Feed-in Tariff, own calculation[2]		1.66 (> 20 MW) 2.08 (< 20 MW)		
	ESDM[3]		2.35		
International data	IEA WEO 2019 (average of India and China)	1.19			1.16 *(2040)*
	Danish technology catalogue		1.25	1.16	1.08
	IRENA (various)	2.37	-	1.08	0.83
	NREL ATB		2.50	1.80	1.64
	UK Government (DECC)			1.43	1.31
Projection	Learning curve – cost trend [%]	-	100%	85%	72%

[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)*

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. The wind farm was developed by Equis Energy and was installed by late 2017 (COD May 2019). The power plant is estimated to generate 198.6 GWh of electricity annually with wind speeds of 6 m/s. The power plant is also expected to reduce greenhouse gas emissions by 160,600 tons of carbon dioxide annually. 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. In addition, the utilization of foreign workers during the construction period of this project is only 27 people and currently, out of 250 domestic workers, 122 of them are local workers. 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. Each of them generates 2.5 MW of electricity. 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)

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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 2019. 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							
	2020	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
				Lower	Upper	Lower	Upper		
Energy/technical data									
Generating capacity for one unit (MWe)	3.5	4.0	5.0						3
Generating capacity for total power plant (MWe)	70	80	100						1
Electricity efficiency, net (%), name plate	100	100	100					A	
Electricity efficiency, net (%), annual average	100	100	100						
Forced outage (%)	2.5%	2.0%	2.0%						
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	14	14						1
Additional data for non thermal plants									
Capacity factor (%), theoretical	35	36	37	20	45	20	45	B	
Capacity factor (%), incl. outages	34	35	36						
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$/MWe)	1.50	1.28	1.08	1.20	2.35	0.80	1.85	D,G	1
- of which equipment	65%	65%	65%					C	2, 3
- of which installation	35%	35%	35%					C	2, 3
Fixed O&M ($/MWe/year)	60 000	51 000	43 200	30 000	70 000	25 000	60 000		4
Variable O&M ($/MWh)	0	0	0						4
Start-up costs ($/MWe/start-up)	0	0	0						

References:

1 PLN data provided by the System Planning Division at PLN. Supported by review of international price data, cf. technology description.

2 IRENA (2015). Renewable Power Generation Cost in 2014

3 Danish Energy Agency, 2012/2016.Technology Data on Energy Plants - Generation of Electricity and District Heating, Energy Storage and Energy Carrier

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 Vestas data provided by the Sales Division for the Asian Pacific.

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

C Equipment: Cost of turbines including transportation. Installation: Electrical infrastructure of turbine, civil works, grid connection, planning and management. The

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).

G 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.

Technology

Technology	Wind power - Offshore								
	2020	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
				Lower	Upper	Lower	Upper		
Energy/technical data									
Generating capacity for one unit (MWe)	8.0	10.0	12.0						3
Generating capacity for total power plant (MWe)	240	300	360						
Electricity efficiency, net (%), name plate	100	100	100					A	
Electricity efficiency, net (%), annual average	100	100	100					A	
Forced outage (%)	4.0%	3.0%	3.0%						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	50	51	52	20	45	20	45	B	2
Capacity factor (%), incl. outages	47.9	49.1	50.7						
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$_2$O (g per GJ fuel)	0	0	0						
Financial data									
Nominal investment (M$/MWe)	3.50	2.98	2.52	2.40	3.70	1.55	2.90	D,G	3
- of which equipment	45%	45%	45%					C	3
- of which installation	55%	55%	55%					C	3
Fixed O&M ($/MWe/year)	72 600	61 700	52 300	58 200	78 200	38 000	57 200		4
Variable O&M ($/MWh)	5.5	4.8	3.9	3.4	5.8	2.7	4.3		4
Start-up costs ($/MWe/start-up)	0	0	0						

References:

1 PLN data provided by Pak Arief Sugiyanto, System Planning Devision at PLN. Supported by review of international price data, cf. technology description.

2 Wind Energy Resources of Indonesia 2014-2017, EMD International A/S, Denmark, financed by the Environmental Support Programme 3 (ESP3) / Danida.

3 Danish Energy Agency, 2012/2016.Technology Data on Energy Plants - Generation of Electricity and District Heating, Energy Storage and Energy Carrier

4 IEA Wind Task 26, 2015, "Wind Technology, Cost, and Performance Trends in Denmark, Germany, Ireland, Norway, the EU, and the USA: 2007–2012".

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.

C Equipment: Cost of turbines including transportation. Installation: Electricical infrastructure of turbine, civil works, grid connection, planning and management. The

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).

G For 2020, uncertainty ranges are based on cost spans of various sources. For 2050, we combine the base uncertainty 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 - Small onshore wind turbines < 1 MW								
	2020	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
				Lower	**Upper**	**Lower**	**Upper**		
Energy/technical data									
Generating capacity for one unit (MWe)	0.85	0.90	0.95						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 (%)	3.0%	2.5%	2.0%						
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)	1.0	1.0	1.0						5, 6
Space requirement (1000 m^2/MWe)	58	58	58						1, 6
Additional data for non thermal plants									
Capacity factor (%), theoretical	35	36	37	20	45	20	45	B	2
Capacity factor (%), incl. outages	34	35	36						
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$_2$O (g per GJ fuel)	0	0	0						
Financial data									
Nominal investment (M$/MWe)	4.00	3.40	2.88	3.00	5.00	3.60	2.16	D,E	5, 6
- of which equipment	55%	55%	55%					C	
- of which installation	45%	45%	45%					C	
Fixed O&M ($/MWe/year)	73 200	62 200	52 700	54900	91500	65900	39500	E	4
Variable O&M ($/MWh)	0	0	0						4
Start-up costs ($/MWe/start-up)	0	0	0						

References:

1 PLN data provided by Pak Arief Sugiyanto, System Planning Devision at PLN. Supported by review of international price data, cf. technology description.

2 Wind Energy Resources of Indonesia 2014-2017, EMD International A/S, Denmark, financed by the Environmental Support Programme 3 (ESP3) / Danida.

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".

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).

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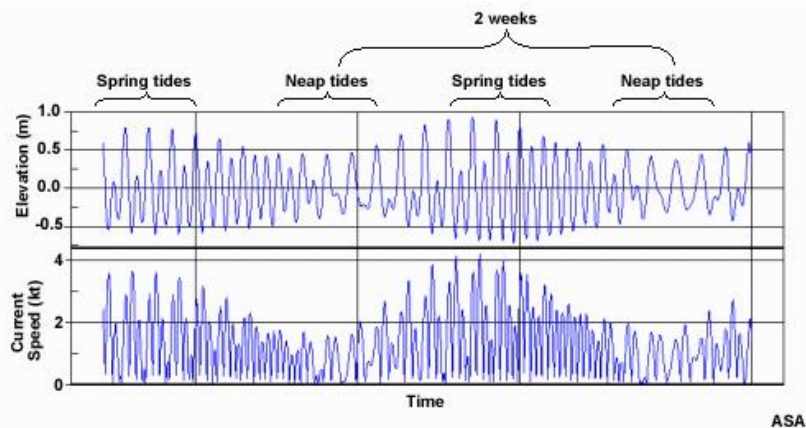
Time series representation of spring and neap tide along with correlation with tidal current speed variation.(ref. 3)

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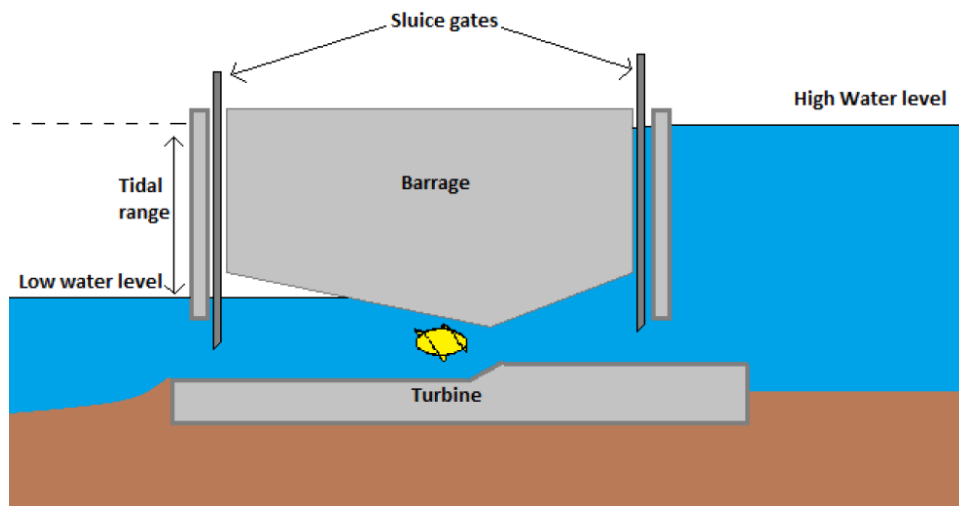
Schematic of tidal impoundment type plant.(ref. 4)

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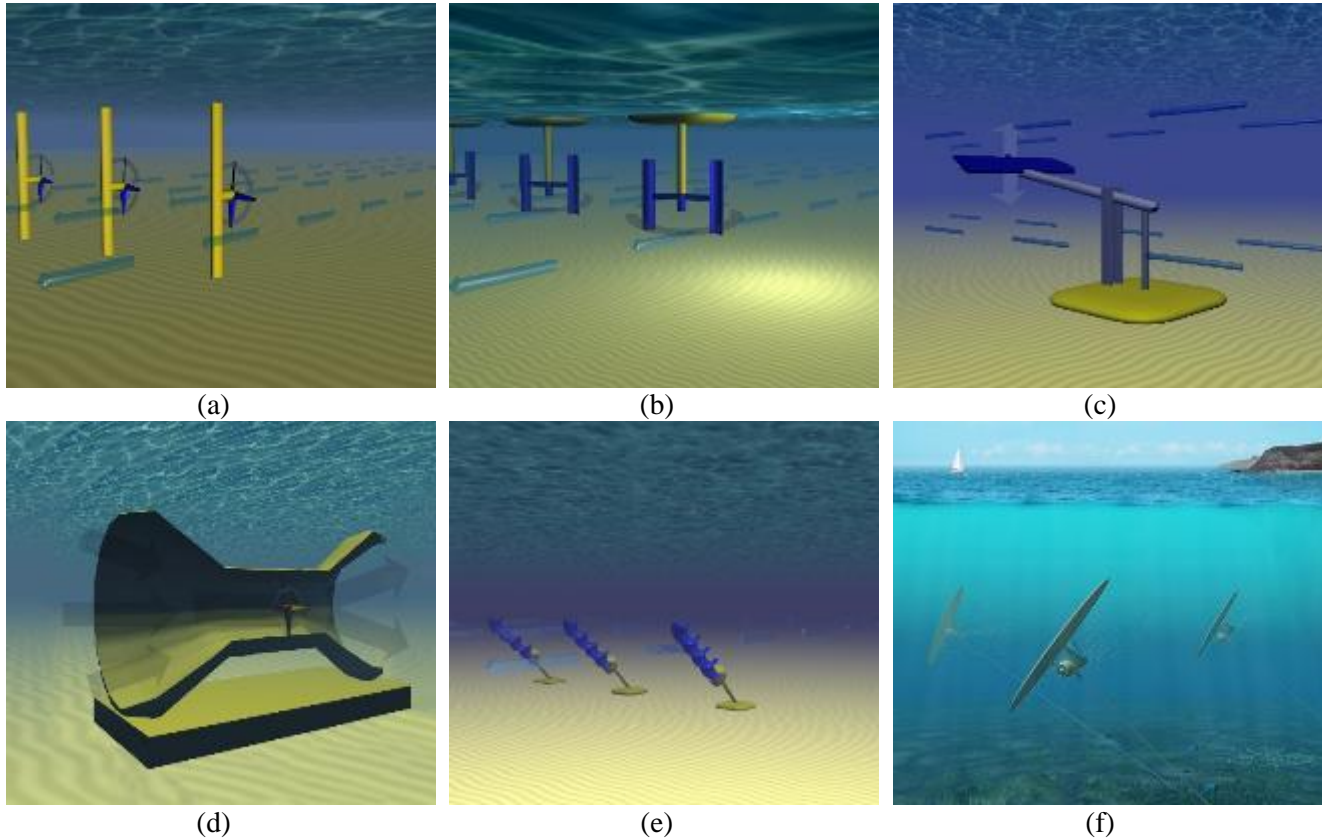
Tidal stream turbine types: (a) Horizontal axis turbine (b) Vertical axis turbine (c) Oscillating hydrofoil (d) Enclosed Tips (Venturi effect device) (e) Archimedes screw (f) Tidal kite (ref. 2)

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:

Figure 17: Active tidal stream capacity by technology

Active capacity (MW): 1 MW, 0.6 MW, 9 MW

Active projects: 1, 2, 4

Active devices: 1, 2, 13

■ Horizontal axis turbine   ■ Tidal kite   ■ Vertical axis turbine
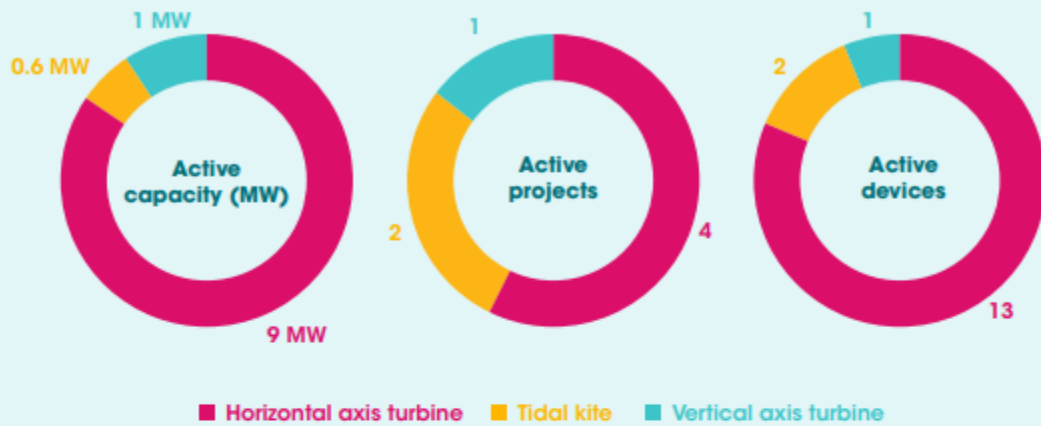
Figure 18: Projected tidal stream capacity and developers by technology

Planned capacity (MW): 251 MW, 11 MW, 1 645 MW

Planned projects: 2, 3, 4, 6, 65

Developers with TRL>6: 2, 1, 5, 1, 20

■ Horizontal axis turbine   ■ Tidal kite   ■ Enclosed tips/open-centre

■ Archimedes screw   ■ Vertical axis turbine   ■ Other
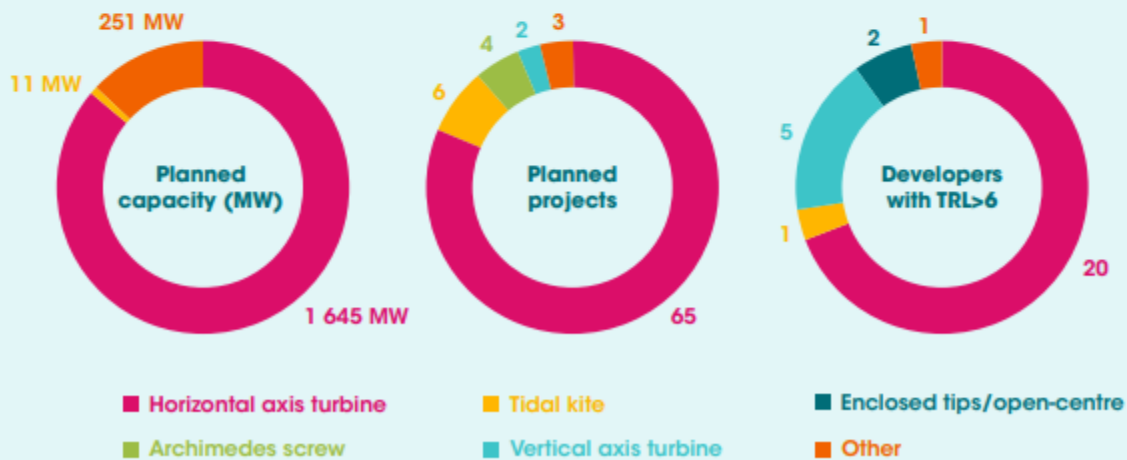
Source: *IRENA ocean energy database*

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.

1 Nacelle
The nacelle houses the control system, gearbox and generator which convert the power into electricity. The electrical power is transmitted onshore by means of a subsea cable.

2 Blades
The length of the blades is about 10.5 metres. The blades rotate with a speed of 10 times per minute during peak flow. The power is optimised by regulating the pitch of the blades.

4 Substructure
The substructure is a steel tripod about 22 metres high, well suited for different environmental terrains and seabed conditions. Thus the total height of the turbine is about 33 meters from base to blade-tip.

3 Ballast Weights
They keep the device in place. Though until now, solely gravity is being used, but according to the environment, some additional form of fixing such as micro-piles may be required.

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.
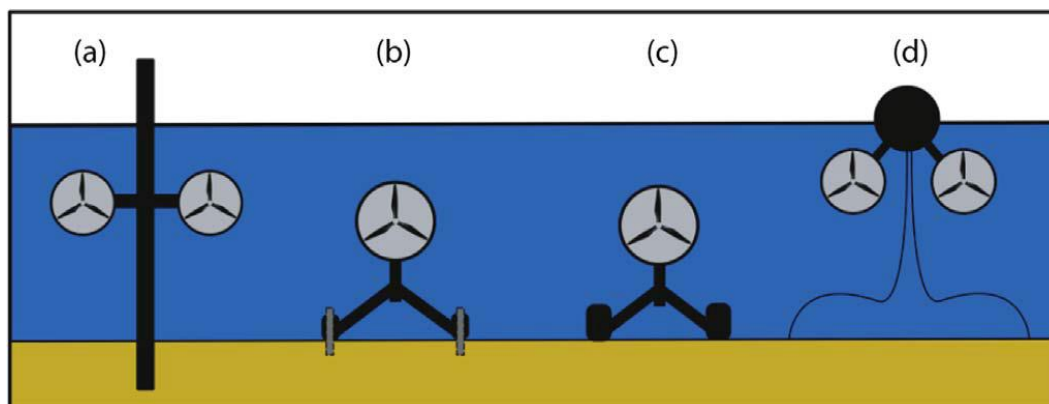

Foundation types: First generation devices (a) Monopile; (b) Piloted; (c) Gravity (d) Pile Foundation.(ref. 7)

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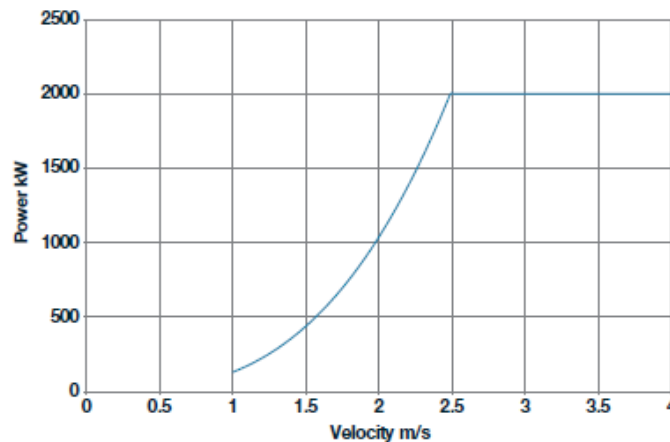
Sample power curve for tidal stream turbine.(ref. 9).

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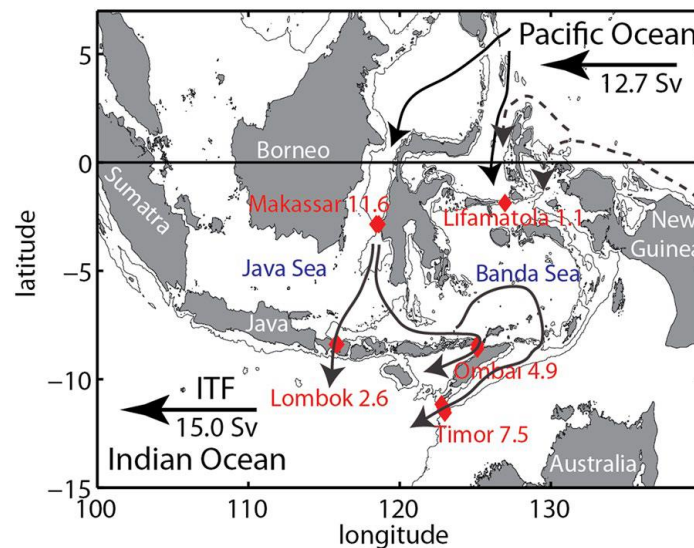
Transport of the currents contributing to the Indonesian Throughflow via different passages. Numbers next to current arrows indicate transport in Sverdrups (Sv) (ref. 14)

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.

R&D	Prototype	Demonstration	Pre-Commercial	Industrial Roll-Out
• Small-scale device validated in lab • Component testing and validation • Small/medium-scale Pilots	• Representative single scale devices with full-scale components • Deployed in relevant sea conditions • Ability to evidence energy generation	• Series or small array of full-scale devices • Deployed in relevant sea conditions • Ability to evidence power generation to Grid • For OTEC and salinity gradient: full functionality downscaled power plant	• Medium-scale array of full-scale devices experiencing interactions • Grid connected to a hub or substation (array) • Deployed in relevant/operational sea conditions • For OTEC and salinity gradient: scalable	• Full-scale commercial ocean energy power plant or farms • Deployed in operational real sea conditions • Mass production of off-the-shelf components and devices
TRL 1-4	TRL 3-6	TRL 5-7	TRL 6-8	TRL 7-9

WAVE
TIDAL STREAM
OTEC/SWAC
SALINITY GRADIENT
TIDAL RANGE

Where ocean energy technologies are in the stages of development (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.
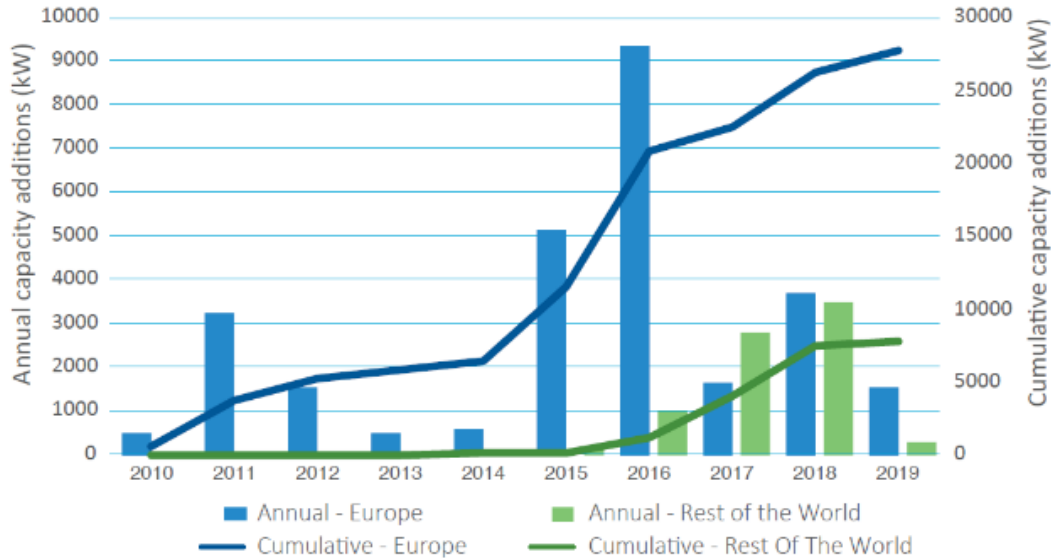
Installed and cumulative tidal stream energy capacity (ref. 20).

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 costs here take into account exchange rates to 2019 US dollars and applicable inflation.

Investment Cost for Tidal Impoundment:

Investment costs [$MUSD_{2019}$/MW]	Estimates	2020	2030	2050
New Catalogue (2020)		**5.5**	**5.1**	**5.1**
UK Government (DECC) (ref. 21)	5.3 (2.9 to 6.9)	6.9	5.3	5.3
Literature (ref. 22)	5.1 (3.6 to 5,7)	5.7	4.8	4.8
IRENA (ref. 23)	4 (proposed/planned)	4		

The recommended values for 2020 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 (2020)		**5.3**	**4.6**	**3.4**
IEA Report (ref. 24)	4.6 (3.4 to 5.7)	5.7	4.6	3.4
Commercial Developer Suggested Values	3 (in UK) 2 (in few years)			
Indonesia-Lombok Project (ref. 25)	5	5		

The recommended cost values here tidal stream in 2020 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

Some examples of international projects are:

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).

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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 2019.

Technology

Technology	Tidal power - Impoundment Type								
	2020	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
				Lower	Upper	Lower	Upper		
Energy/technical data									
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)	0.20	0.20	0.20	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	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$/MWe)	5.5	5.1	5.1	2.9	7.5	2.9	7.5	E	1,2,4
- of which equipment									
- of which installation									
Fixed O&M ($/MWe/year)	70,800	62,500	35,700	23,400	72,000	23,400	72,000	E	1,2,3,4
Variable O&M ($/MWh)	0	0	0						
Start-up costs ($/MWe/start-up)									
Technology specific data									

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

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

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

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								
	2020	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
				Lower	Upper	Lower	Upper		
Energy/technical data									
Generating capacity for one unit (MWe)	1	2	2	0.1	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$_2$O (g per GJ fuel)	0	0	0						
Financial data									
Nominal investment (M$/MWe)	5.3	4.6	3.4	3.0	7.1	2.0	7.1	B	1,2,3
- of which equipment	87%	87%	87%	83%	91%	83%	91%		1,2
- of which installation	13%	13%	13%	9%	17%	9%	17%		1,2
Fixed O&M ($/MWe/year)	283,000	230,000	114,000	93,000	412,000	93,000	412,000	B	1,2
Variable O&M ($/MWh)	12	9	7						4
Start-up costs ($/MWe/start-up)									
Technology specific data									

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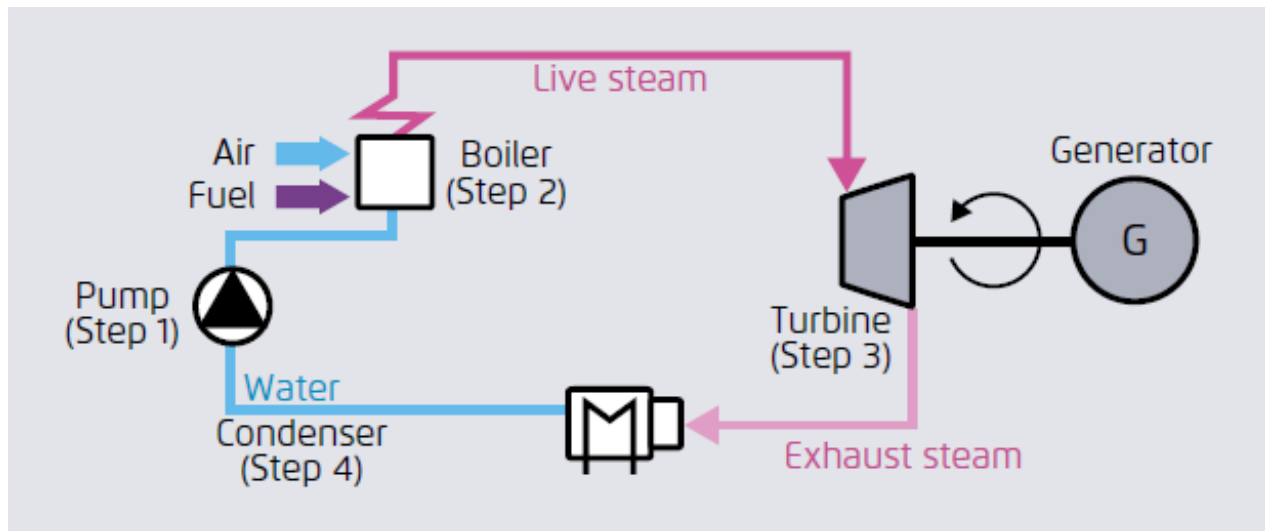
Schematic representation of operational flow of steam based Rankine cycle in coal plants (ref. 2).

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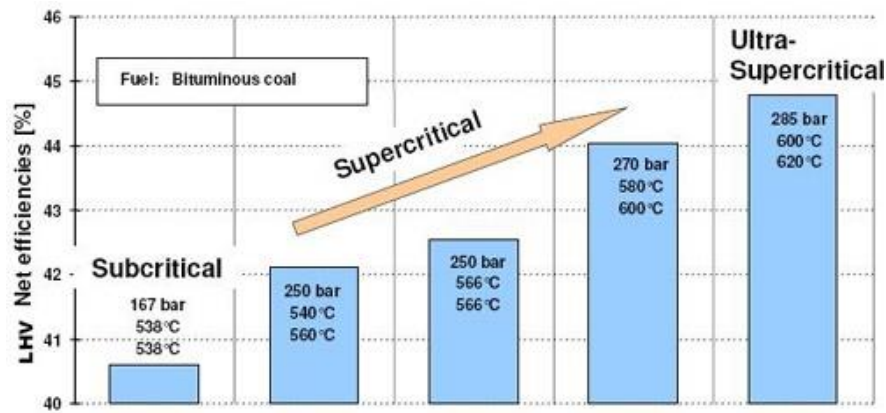
Differences between sub-, super-, and ultra-supercritical plant (ref. 6).

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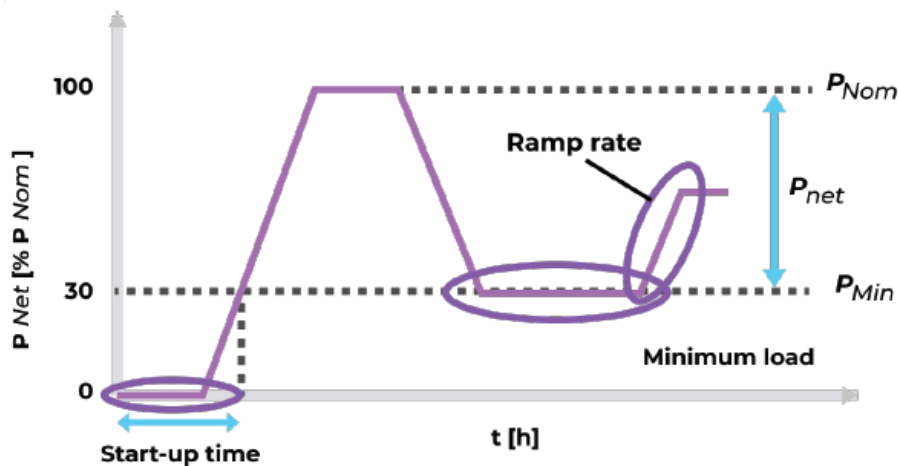
Key flexibility parameters of a power plant (ref. 3).

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 reduced the minimum load from 36% P_{nom} to 26% P_{nom}.	Fire stability and boiler design
õ P g y öblhᴏ w 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 plant 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
Startup time (hours)	2 to 10	1.3 to 6
Startup cost (USD/MW inst 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[3].

Investment cost (in USD) estimated for specific 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

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

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).

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 estimation
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 subcritical power plants.

Investment costs [MUSD$_{2019}$/MW]	2018	2020	2030	2050
New Catalogue (2020)		1.65	1.60	1.55
2017 catalogue		1.65	1.60	1.55
ESDM[1]		1.15		
Local cases[2]		1.25		
Danish technology catalogue[3]	-	2.13	2.08	1.99
IEA WEO 2019 (average of India and China)	1.00			
Learning curve - cost trend [%]		100%	98%	96%

[1] *ESDM presentation on "KATADATA Shifting Paradigm: Transition towards sustainable energy". Sampe L. Purba (26 August 2020)*

[2] *Average CAPEX of Indonesian project constructed or planned in 2019-2021.*

[3] *The Danish Technology Catalogue reports values for combined heat and power (CHP) plants. Investment costs are higher for CHP plants than for condensing units.*

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:

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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 2019. 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								
	2020	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	150	150	150	100	200	100	200		1
Generating capacity for total power plant (MWe)	150	150	150	100	200	100	200		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 configuration									
Ramping (% per minute)	3.5	3.5	3.5	2	4	2	4	B	1
Minimum load (% of full load)	30	25	20	25	50	10	30	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$/MWe)	1.65	1.60	1.55	1.00	1.70	1.05	1.70	E,H	1,3
- of which equipment									
- of which installation									
Fixed O&M ($/MWe/year)	45 300	43 900	42 600	34 000	56 600	32 000	53 300	G	1,3
Variable O&M ($/MWh)	0.13	0.12	0.12	0.09	0.16	0.09	0.15	G	1,3
Start-up costs ($/MWe/start-up)	110	110	110	50	200	50	200		5

References:

1 PLN, 2017, data provided the System Planning Division at PLN

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.

Technology

Technology	Supercritical coal power plant							Note	Ref
	2020	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data				**Lower**	**Upper**	**Lower**	**Upper**		
Generating capacity for one unit (MWe)	600	600	600	300	800	300	800		1
Generating capacity for total power plant (MWe)	600	600	600	300	800	300	800		1
Electricity efficiency, net (%), name plate	38	39	40	33	40	35	42		1,3,6,7
Electricity efficiency, net (%), annual average	37	38	39	33	40	35	42		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	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 configuration									
Ramping (% per minute)	4	4	4	3	4	3	4	B	1
Minimum load (% of full load)	30	25	20	25	50	10	30	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$_2$O (g per GJ fuel)	-	-	-	-	-	-	-		
Financial data									
Nominal investment (M$/MWe)	1.40	1.36	1.32	1.05	1.75	0.99	1.65	E,G,H	1,3,6,7
- of which equipment									
- of which installation									
Fixed O&M ($/MWe/year)	41 200	40 000	38 700	30 900	51 500	29 000	48 400	G	1,3,6,7
Variable O&M ($/MWh)	0.12	0.12	0.11	0.09	0.15	0.08	0.14	G	1,3
Start-up costs ($/MWe/start-up)	50	50	50	40	100	40	100		5

References:

1 PLN, 2017, data provided the System Planning Division at PLN

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, Projected Costs of Generating Electricity, 2015.

7 IEA, World Energy Outlook, 2015.

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

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.

Technology

Technology	Ultra-supercritical coal power plant							Note	Ref
	2020	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
				Lower	Upper	Lower	Upper		
Energy/technical data									
Generating capacity for one unit (MWe)	1000	1000	1000	700	1200	700	1200		1
Generating capacity for total power plant (MWe)	1000	1000	1000	700	1200	700	1200		1
Electricity efficiency, net (%), name plate	43	44	45	40	45	42	47		1,3,6,7
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	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 configuration									
Ramping (% per minute)	5	5	5	4	5	4	5	B	1
Minimum load (% of full load)	30	25	20	25	50	10	30	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$/MWe)	1.52	1.48	1.43	1.14	1.91	1.07	1.79	E,G,H	1,3,6,7
- of which equipment									
- of which installation									
Fixed O&M ($/MWe/year)	56 600	54 900	53 200	42 500	70 800	39 900	66 500	G	1,3,6,7
Variable O&M ($/MWh)	0.11	0.11	0.10	0.08	0.14	0.08	0.13	G	1,3
Start-up costs ($/MWe/start-up)	50	50	50	40	100	40	100		5

References:

1 PLN, 2017, data provided the System Planning Division at PLN

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, Projected Costs of Generating Electricity, 2015.

7 IEA, World Energy Outlook, 2015.

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

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.

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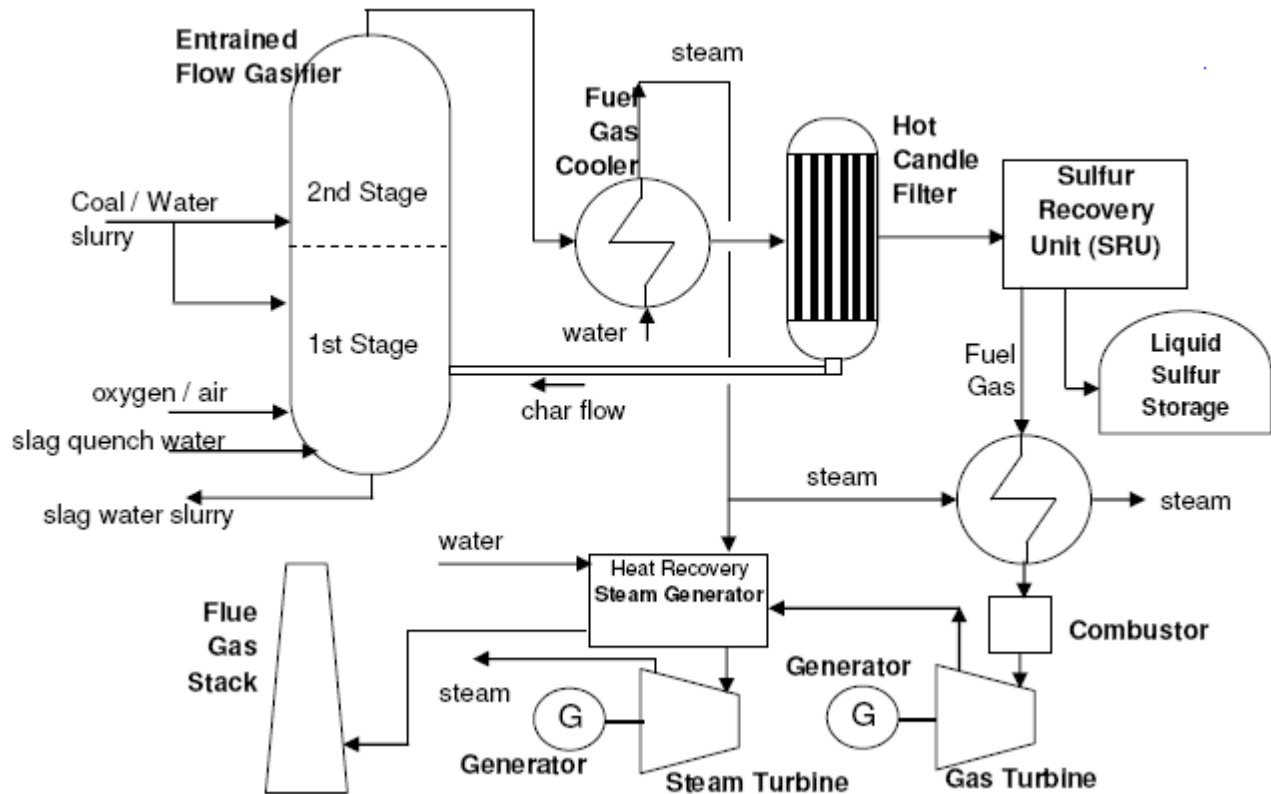
IGCC plant scheme using entrained flow gasifier technology (ref. 5).

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).

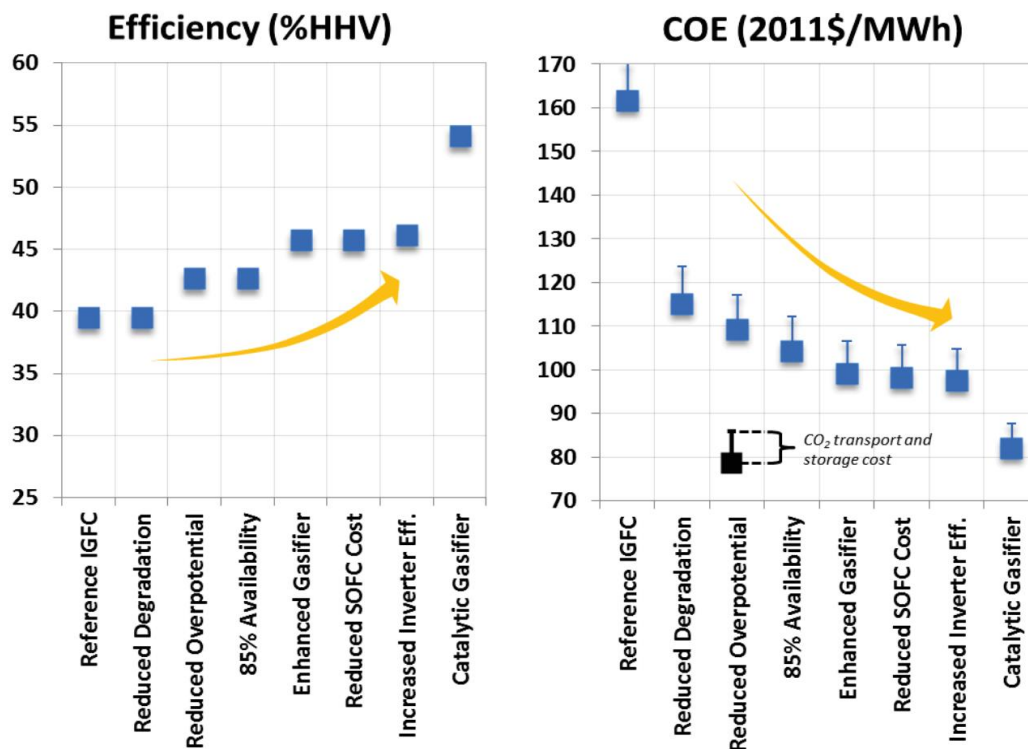The pathways are built up to incorporate these technologies in a cumulative manner:

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 2019. 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	IGCC								
	2020	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
				Lower	Upper	Lower	Upper		
Energy/technical data									
Generating capacity for one unit (MWe)	150-200	150-200	150-200					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 (%)	6	6	6						2
Planned outage (weeks per year)	7	7	7					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 configuration									
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)	15-80	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$/MWe)	2.40	2.21	2.04	2.16	3.50	1.75	3.00	H	6,13
- of which equipment (%)	30	30	30	25	50	25	50		6,13
- of which installation (%)	70	70	70	50	75	50	75		6
Fixed O&M ($/MWe/year)	60 000	58 200	56 400	56 100	68 400	52 700	68 400		6
Variable O&M ($/MWh)	12.0	11.6	11.2	15.0	7.9	14.0	7.9		6,13
Start-up costs ($/MWe/start-up)	100	100	100					E	

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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. 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.
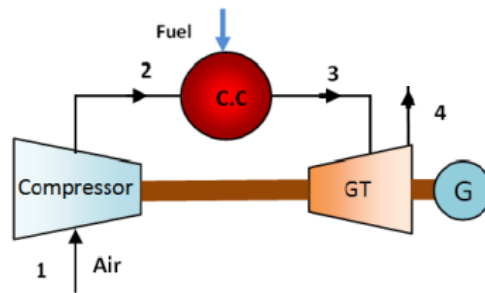
Process diagram of a CCGT (ref. 1)

There are in general two types of gas turbines;
1. industrial turbines (also called heavy-duty)
2. aero-derivative turbine

Industrial gas turbines differ from aero-derivative turbines in the way that the frames, bearings and blading are of heavier construction. Additionally, industrial gas turbines have longer intervals between services compared to the aero-derivatives.

Aero-derivative turbines benefit from higher efficiency than industrial ones and the most service-demanding module of the aero-derivative gas turbine can normally be replaced in a couple of days, thus keeping a 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 (radial) gas turbines below 100 kW are now on the market, the so-called micro-turbines. These are often equipped with preheating of combustion air based on heat from gas turbine exhaust (integrated recuperator) to achieve reasonable electrical efficiency (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 be started and stopped within minutes, supplying power during peak demand. Because they are less power efficient than combined cycle plants, they are in most places used as peak or reserve power plants, which operate anywhere from several hours per day to a few dozen hours per year.

However, every start/stop has a measurable influence on service costs and maintenance intervals. As a rule-of-thumb, a start costs 10 hours in technical life expectancy.

Gas turbines are able to operate at part load. This reduces the electrical efficiency and at lower loads the emission of e.g. NOx and CO will increase. The increase in NOx emissions with decreasing load places a regulatory limitation on the ramping ability. This can be solved in part by adding de-NOx units.

Advantages/disadvantages
Advantages:
Simple-cycle gas turbine plants have short start-up/shut-down time, 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 have continuous combustion with non-cooled walls. This means a very complete combustion and low levels of emissions (other than NOx). 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
Gas turbines are a very well-known and mature technology – i.e. category 4.

Increased efficiency for simple-cycle gas turbine configurations has also been reached through inter-cooling and recuperators. Research into humidification (water injection) of intake air processes (HAT) is expected to lead to increased efficiency due to higher mass flow through the turbine.

Additionally, continuous development for less polluting combustion is taking place. Low-NOx combustion technology is assumed. Water or steam injection in the burner section may reduce the NOx emission, but also the total efficiency and thereby possibly the financial viability. The trend is more towards dry low-NOx combustion, which increases the specific cost of the gas turbine.

Examples of current projects
Large Scale Gas Turbine Power Plant: Celukan Bawang Gas Turbine Power Plant (Ref. 2)
Celukan Bawang Gas Turbine Power Plant is located in Bali. This project is as a response to the Bali local government policy that Bali would adopt clean energy policy. This project is funded by Chinese company, Shanghai Electric Group Corp (SEC), with amount of 1.3 billion USD. This capital cost is going to be used to develop a 2 x 350 MW Gas Power Plant at Celukan Bawang, Bali. The project will be built on an area of 50 hectares. Construction will start in Semester 1 of 2020.

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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 2019. 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	Simple Cycle Gas Turbine - large system								
	2020	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data				**Lower**	**Upper**	**Lower**	**Upper**		
Generating capacity for one unit (MWe)	50	50	50	35	65	35	65		3
Generating capacity for total power plant (MWe)	100	100	100	35	150	35	150		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	3,8
Minimum load (% of full load)	20	30	15	30	50	10	40	A	6
Warm start-up time (hours)	0.25	0.23	0.20						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		7
SO_2 (degree of desulphuring, %)	-	-	-	-	-	-	-	E	
NO_X (g per GJ fuel)	86	60	20	20	86	20	86	A,D	3,7
CH_4 (g per GJ fuel)	-	-	-	-	-	-	-		
N_2O (g per GJ fuel)	-	-	-	-	-	-	-		
Financial data									
Nominal investment (M$/MWe)	0.77	0.73	0.68	0.65	1.20	0.55	1.10	F,G,H	1-5
- of which equipment (%)	50	50	50	50	50	50	50		9
- of which installation (%)	50	50	50	50	50	50	50		9
Fixed O&M ($/MWe/year)	23 200	22 500	21 800	17 400	29 000	16 400	27 300	B	1-5
Variable O&M ($/MWh)									
Start-up costs ($/MWe/start-up)	24	24	24	18	30	18	30	B	6

References:

1 IEA, Projected Costs of Generating Electricity, 2015.

2 IEA, World Energy Outlook, 2015.

3 Danish Energy Agency, 2015, "Technology Catalogue on Power and Heat Generation".

4 Learning curve approach for the development of financial parameters.

5 Energy and Environmental Economics, 2014, "Capital Cost Review of Power Generation Technologies - Recommendations for WECC's 10- and 20-Year Studies".

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 Vuorinen, A., 2008, "Planning of Optimal Power Systems".

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. For 2050, we combine the base uncertainty 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.

9. 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.
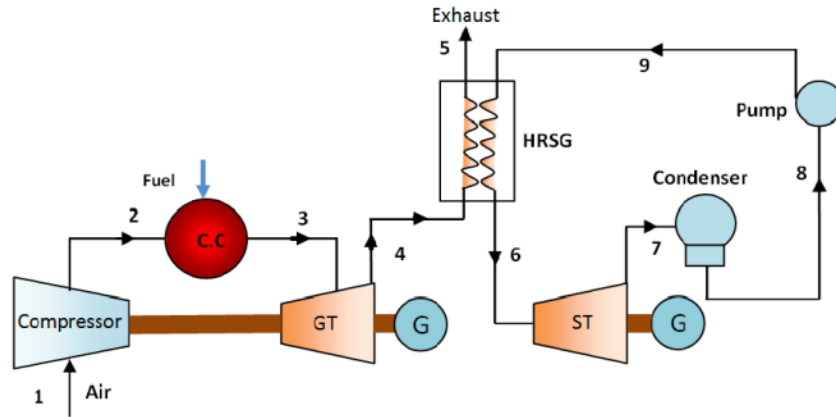
Process diagram of a CCGT (ref. 1)

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.

Investment costs [MUSD$_{2019}$/MW]	2018	2020	2030	2050
New Catalogue (2020)		0.77	0.73	0.68
Existing catalogue		0.75	0.71	0.66
ESDM[1]		1.92		
Danish technology catalogue[2]		0.99	0.93	0.90
NREL's ATB		1.02	0.94	0.88
IEA WEO 2019 (average of India and China)	0.63			
Learning curve - cost trend [%]	-	1	0.95	0.89

[1] *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 4th 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 worker will be recruited and about 200 workers stay when the plant start 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.

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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 2019. 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	Combined Cycle Gas Turbine								
	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	600	600	600	200	800	200	800		1
Generating capacity for total power plant (MWe)	600	600	600	200	800	200	800		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$/MWe)	0.69	0.66	0.61	0.65	1.00	0.55	0.90	F,H	1,3,10
- of which equipment (%)	50	50	50	50	50	50	50		9
- of which installation (%)	50	50	50	50	50	50	50		9
Fixed O&M ($/MWe/year)	23 500	22 800	22 100	17 600	29 400	16 600	27 600	B	1,3
Variable O&M ($/MWh)	2.30	2.23	2.16	1.73	2.88	1.62	2.70	B	1
Start-up costs ($/MWe/start-up)	80	80	80	60	100	60	100	B	6

References:

1 PLN, 2017, data provided the System Planning Division at PLN

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 uncertainy 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.

10. CO_2 CAPTURE AND STORAGE (CCS)

This chapter describes the essential features of the most prominent carbon capture and storage technologies, with a mention of the main uses. Notwithstanding, the data at the end of this Chapter considers only carbon capture performance and costs (and not the storage and eventual utilization), as the focus of this analysis is power generation technologies and the downstream processes largely varies by application/geography.

Technology description
The increase of atmospheric CO_2 concentration in the last decades is to a large extent ascribable to the combustion of fossil fuels. Carbon Capture and Storage (CCS) can allow the presence of fossil fuels in a CO_2-constrained future. In addition, CCS can generate negative emissions if used on biomass, which could be necessary to limit temperature increase in the long run according to scenarios from IEA and IPCC. CCS can be divided into Capture, Compression, Transport and Storage, which are described in the following sections.

CO_2 Capture
The CO_2 volume of fossil fired power plants ranges from 3-15% of the flue gas volume. 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 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).

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).

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).

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
The major barrier for extensive use of CO_2 removal technology are the high costs of separating and compressing the CO_2. The additional energy required for this process typically reduces the 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.

CO₂ 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; 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.

CO₂ storage (and utilization)

CO_2 can be stored in different geological sites, the main opportunities being saline aquifers, salt caverns and hydrocarbon formations, either onshore or offshore. Aquifers and caverns have the largest potential for long-term CO_2 storage, as saline aquifers are widespread and hold big storage capabilities (ref. 4). The figure below sketches out the post-capture treatment of CO_2 captured at a power plant (or industrial facility).

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 the 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 Enhanced Oil and Gas Recovery (EOGR) and the production of synthetic fuels (methanol, 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.
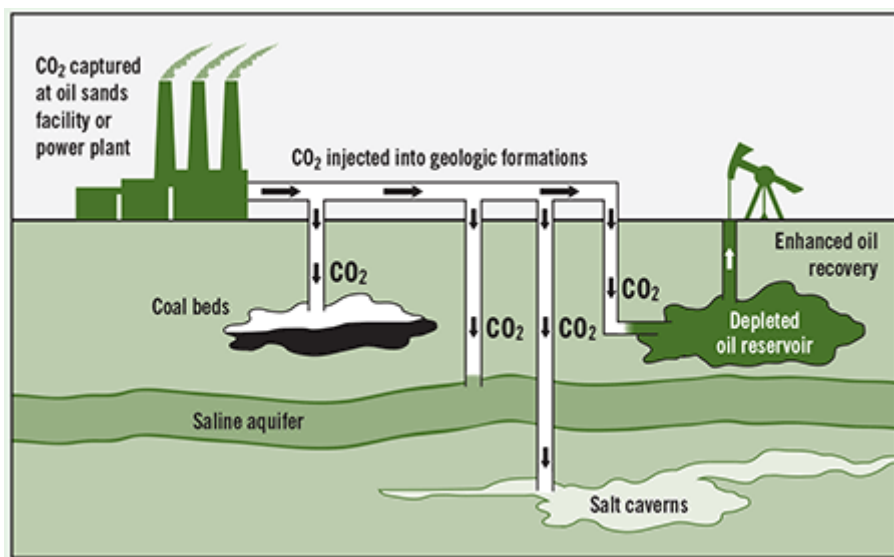
Post-capture treatment of CO₂. Source: Energywatch.

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 tonne increase. For this reason, it may be preferred to operate CCS plants at base load.

Advantages and disadvantages

Advantages
- **Post-combustion capture**. It can be applied to most of the existing coal-fired or thermal power plants.
- **Pre-combustion capture**. 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.
- **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. There exist potential cost savings with respect to post-combustion capture in that the boiler size is reduced, since nitrogen is separated. Power plants can also be retrofitted in order to include oxy-fuel combustion (Ref. 6). However, this is less attractive in that issues in air ingress arise, resulting in higher CAPEX and OPEX. Circulating fluidized bed (CFB) are more suitable for oxy-fuel retrofit (ref. 1).

Disadvantages
- **Post-combustion capture**. The CO_2 is diluted in the flue gas and at ambient pressure, which makes it harder to sequester 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 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. 15). The sequestered CO_2 comes at a lower purity (70-90%) than in post-combustion, thus purification costs are higher (this is needed before compression and transportation).

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. Failures of CO_2 pipeline can be caused by a poor pipeline design, corrosion due to impurities in the CO_2 stream and third-party inference. All these risks can be mitigated with better-conceived designs, operations and infrastructure management. 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 falls 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 (ref. 9).
- **Ammonia** (NH_3). It is the only pollutant for which 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 power sector point sources are shown in red dots.

CO₂ point sources in Indonesia (ref. 18).
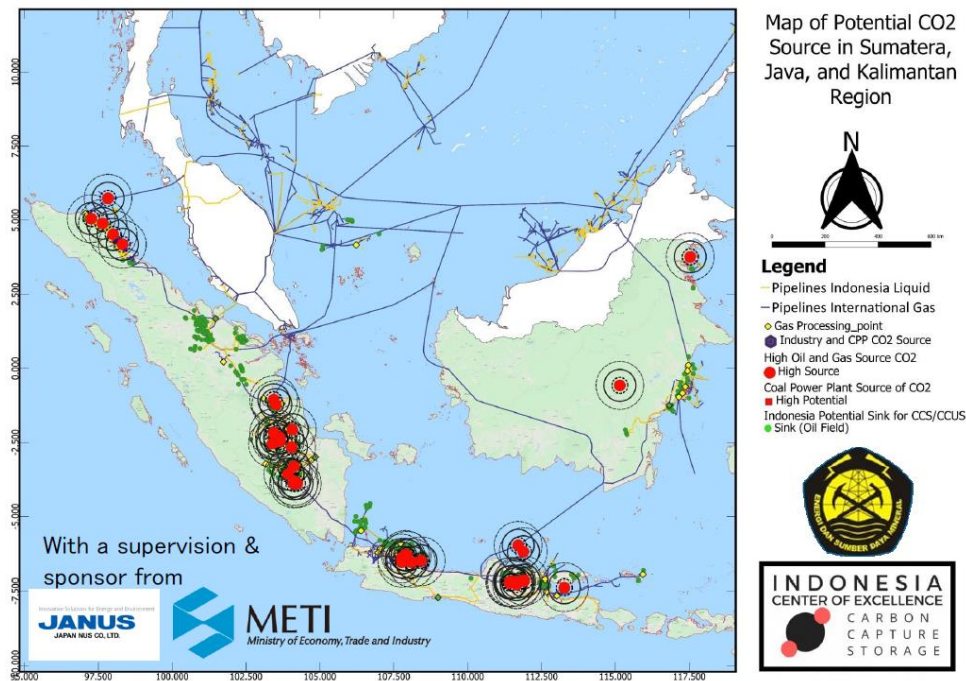
Examples of current projects
- *Sukowati pilot project* is an oilfield located in East Java, Indonesia. It has 5 existing wells, one of which is not in production and will be used as a CO_2 injection well with the objective of EOR. If the pilot proves to be successful, a commercial-scale project could 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 on 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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Data sheets

The following pages contain the data sheets of the technology. All costs are stated in U.S. dollars (USD), price year 2019. 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.

Cost figures are given as an additional cost with respect to the same technology without CCS.

Technology	Supercritical coal power plant with CCS								
	2020	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
				Lower	**Upper**	**Lower**	**Upper**		
Energy/technical data									
Generating capacity for one unit (MWe)	-60	-60	-60					A	1
Generating capacity for total power plant (MWe)	-60	-60	-60					A	1
Electricity efficiency, net (%), name plate	-7	-7	-7						1
Electricity efficiency, net (%), annual average	-8	-8	-8						1
Forced outage (%)	+7	+7	+7						
Planned outage (weeks per year)									
Technical lifetime (years)									
Construction time (years)									
CO_2 emission reduction (%)	-89	-90	-90					B	1
Space requirement (1000 m^2/MWe)									
Additional data for non thermal plants									
Capacity factor (%), theoretical									
Capacity factor (%), incl. outages									
Ramping configuration									
Ramping (% per minute)	4	4	4					C	7
Minimum load (% of full load)	30	30	30					D	7
Warm start-up time (hours)	4	4	4					E	8
Cold start-up time (hours)	12	12	12					E	8
Environment									
PM 2.5 (mg per Nm3)	150	100	100						3,7
SO_2 (degree of desulphuring, %)	97	97	97						3,7
NO_X (g per GJ fuel)	263	263	263						3,7
CH_4 (g per GJ fuel)									
N_2O (g per GJ fuel)									
Financial data									
Nominal investment (M$/MWe)	+1.95	+1.79	+1.42	+1.60	+2.29	+1.17	+1.67		2,5,9,10
- of which equipment (%)	30	30	30	25	50	25	50		1
- of which installation (%)	70	70	70	50	75	50	75		1
Fixed O&M ($/MWe/year)	+41800	+40500	+39300	+13000	+50000	+13000	+50000		1,7,9
Variable O&M ($/MWh)	+3.10	+3.01	+2.91	+2.50	+8.20	+2.35	+7.71		1,5,9

References:

1 Global CCS Institute, Global costs of carbon capture and storage, 2017

2 Zero emissions platform, The Costs of CO2 Capture, Transport and Storage

3 Koornneef J., 2011, Carbon Dioxide Capture and Air Quality

4 IEAGHG, Operating Flexibility of Power Plants with CCS

5 EIA, 2016, Capital Cost Estimates for Utility Scale Electricity Generating Plants

6 Utrecht University & Energy Research Center of Netherlands, The flexibility requirements for power plants with CCS in a future energy system with a large share of intermitent renewable energy sources

7 Danish Energy Agency, "Technology data - Generation of electricity and district heating", 2020

8 IEAGHG, Operating Flexibility of Power Plants with CCS

9 NREL ATB 2020

10 IEA, Energy Technology Perspectives - Special Report on Carbon Capture, Utilisation and Storage, 2020.

Notes:

A 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.

Technology	Natural Gas Combined Cycle with CCS								
	2020	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data				**Lower**	**Upper**	**Lower**	**Upper**		
Generating capacity for one unit (MWe)	-40	-40	-40					A	1
Generating capacity for total power plant (MWe)	-40	-40	-40					A	1
Electricity efficiency, net (%), name plate	-7	-7	-7						1
Electricity efficiency, net (%), annual average	-8	-8	-8						1
Forced outage (%)	+5	+5	+5						
Planned outage (weeks per year)									
Technical lifetime (years)	-								
Construction time (years)									
CO_2 emission reduction (%)	-87	-90	-90			-90	-99	B	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					C	6
Minimum load (% of full load)	45	45	45					D	6
Warm start-up time (hours)	2.0	2.0	2.0					E	4
Cold start-up time (hours)	4.0	4.0	4.0					E	4
Environment									
PM 2.5 (mg per Nm3)	30	30	30						3,6
SO_2 (degree of desulphuring, %)	99	99	99						3,6
NO_X (g per GJ fuel)	80	80	80						3,6
CH_4 (g per GJ fuel)	-	-	-						
N_2O (g per GJ fuel)	-	-	-						
Financial data									
Nominal investment (M$/MWe)	+1.15	+0.97	+0.75	+0.85	+1.56	+0.60	+1.02		1,7,8
- of which equipment (%)	40	40	40	30	60	30	60		1
- of which installation (%)	60	60	60	40	70	40	70		1
Fixed O&M ($/MWe/year)	+9000	+8700	+8500	+7000	+14000	+6600	+14000		1,7,8
Variable O&M ($/MWh)	+1.20	+1.16	+1.13	+0.60	+4.00	+0.60	+4.00		1,7,8

References:

1 Global CCS Institute, Global costs of carbon capture and storage, 2017

2 Zero emissions platform, The Costs of CO2 Capture, Transport and Storage

3 Koornneef J., 2011, Carbon Dioxide Capture and Air Quality

4 IEAGHG, Operating Flexibility of Power Plants with CCS

5 Utrecht University & Energy Research Center of Netherlands, The flexibility requirements for power plants with CCS in a future energy system with a large share of

6 Danish Energy Agency, "Technology data - Generation of electricity and district heating", 2020

7 NREL ATB 2020

8 IEA, Energy Technology Perspectives - Special Report on Carbon Capture, Utilisation and Storage, 2020.

Notes:

A 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.

Technology	IGCC with CCS								
	2020	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	-65	-65	-65					A	1
Generating capacity for total power plant (MWe)	-65	-65	-65					A	1
Electricity efficiency, net (%), name plate	-7	-7	-7						1
Electricity efficiency, net (%), annual average	-8	-8	-8						1
Cold gas efficiency (%)									
Forced outage (%)	+6	+6	+6						
Planned outage (weeks per year)									
Technical lifetime (years)	-								
Construction time (years)									
CO_2 emission reduction (%)	-86	-90	-90			-90	-99	B	1
Space requirement (1000 m^2/MWe)	-	-	-	-	-	-	-		
Additional data for non thermal plants									
Capacity factor (%), theoretical	-	-	-	-	-	-	-		
Capacity factor (%), incl. outages	-	-	-	-	-	-	-		
Ramping configuration									
Ramping (% per minute)	3	3	3					C	6
Minimum load (% of full load)	50	50	50					D	6
Warm start-up time (hours)	6	6	6						4
Cold start-up time (hours)	15-80	15-80	15-80						4,7
Environment									
PM 2.5 (mg per Nm3)	115	115	115						3,6
SO_2 (degree of desulphuring, %)	99	99	99						3,6
NO_X (g per GJ fuel)	173	173	173						3,6
CO (g per GJ fuel)									
Financial data									
Nominal investment (M$/MWe)	+0.95	+0.87	+0.69	+0.475	+1.19	+0.35	+0.86	E	1,8,9
- of which equipment (%)	25	25	25	20	40	20	40		1
- of which installation (%)	75	75	75	60	80	60	80		1
Fixed O&M ($/MWe/year)	+8900	+8600	+8400	+7100	+15000	+6700	+15000		1,8
Variable O&M ($/MWh)	+5.30	+5.14	+4.98	+3.97	+6.63	+3.74	+6.23		1,8

References:

1 Global CCS Institute, Global costs of carbon capture and storage, 2017

2 Zero emissions platform, The Costs of CO2 Capture, Transport and Storage

3 Koornneef J., 2011, Carbon Dioxide Capture and Air Quality

4 IEAGHG, Operating Flexibility of Power Plants with CCS

5 Utrecht University & Energy Research Center of Netherlands, The flexibility requirements for power plants with CCS in a future energy system with a large share of intermitent renewable energy sources

6 Danish Energy Agency, "Technology data - Generation of electricity and district heating", 2020

7 EPRI, 2015, Increasing the Flecibility of IGCC Power Plants

8 NREL ATB 2020

9 IEA, Energy Technology Perspectives - Special Report on Carbon Capture, Utilisation and Storage, 2020.

Notes:

A 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 Pre-combustion capture is assumed to cause a cost increase ranging between 30-50% of the IGCC price.

11.   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. We will in this chapter focus on the solid biomass for combustion to power generation.
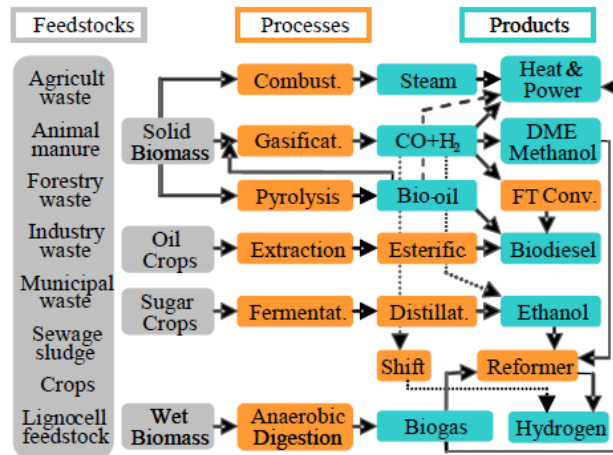
Biomass conversion paths (ref. 1)

The technology used to produce electricity in biomass power plants depends on the biomass resources. Due to the lower heating value of biomass compared to coal, the electric efficiency is lower – 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 abundant 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 bunchs	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 ranges from 5 – 18 GJ/ton, with the palm oil empty fruit brunches (EFB) as the lowest and coconut shells as the highest.

Total current installed capacity of biomass (including biogas and MSW) power plants in Indonesia for 2019 is 1,889.8 MW (Ministry of Energy and Mineral Resources, 2019). Most of these power plants are operated by industries using various types of biomass 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 presents mass balance for relevant raw materials.

(a)

(b)

(c)

(d)
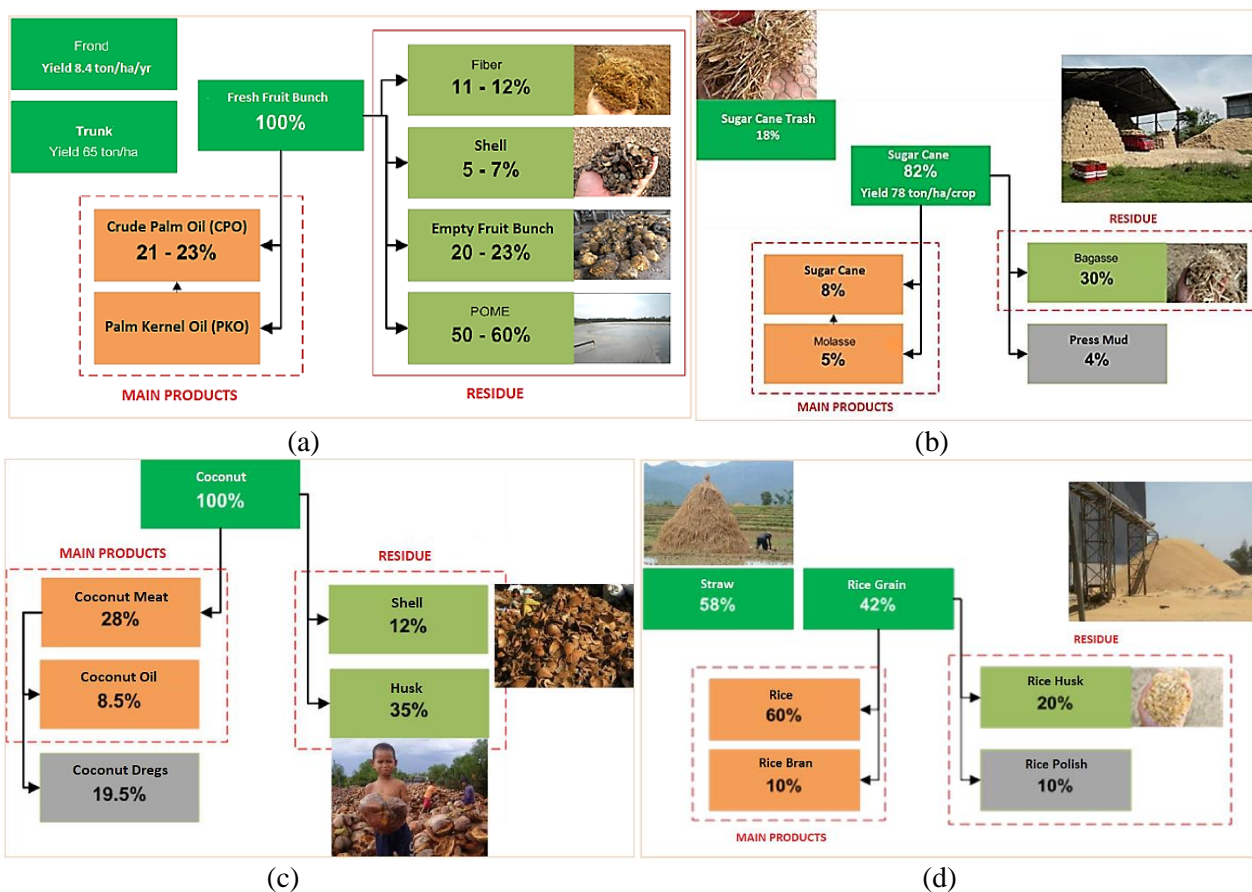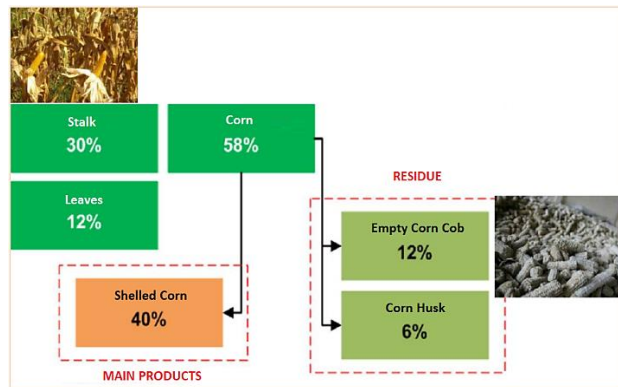
(e)

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 input capacity of 30 tons of palm fresh fruit bunch 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).
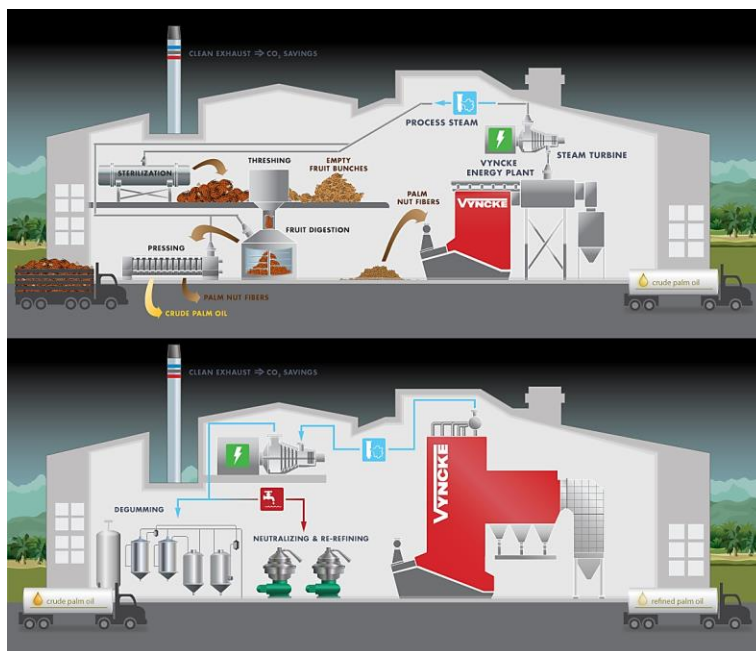
Typical combined heat and power from palm oil solid waste (Source: Vyncke)

Palm oil based feedstock

Beside as ingredients 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. Source: LAMNET by ETA of Italy, WIP of Germany and EUBIA of Belgium, 2004.

Chemical Nomenclature	Methyl Ester
Cetane Number	54
Density (kg/liter)	0.88
LHV (MJ/kg)	37.3

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 starts 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 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 (Source: 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 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 shell and wood pellets.

Input
Biomass, e.g. residues from industries (wood waste, empty fruit bunchs, coconut shell, etc.), wood chips (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 reduction of emissions.

Other exotic biomasses as empty fruit bunch pellets (EFB) and palm kernel shells (PKS) are available in the 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.
- No emission of greenhouse gasses from operation.
- Using biomass waste will usually be cheap.

Disadvantages:
- The availability of biomass feedstock is locally dependent.
- 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)

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 forests 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 favorable 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.
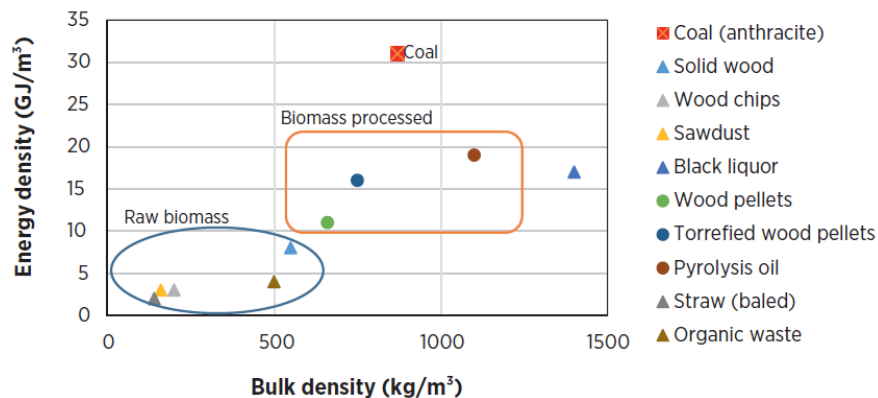
Energy density of biomass and coal (ref. 11).

MSW incineration, anaerobic digestion, land-fill 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.
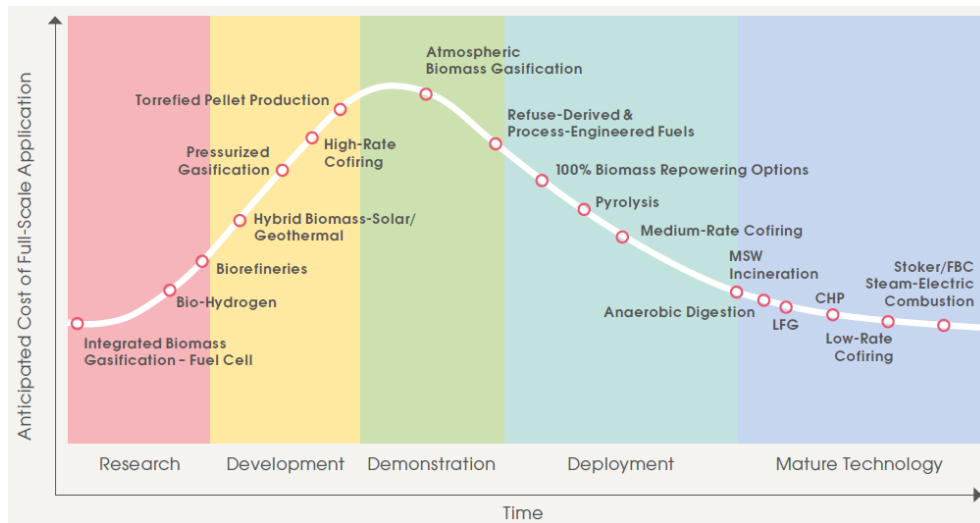
Biomass power generation technology maturity status (ref. 12).

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%

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 suggests investment cost figures of around 2.0 MUSD/MW.

Investment cost [MUSD/MW]		2018	2020	2030	2050
Catalogues	**New Catalogue (2020)**		**2.00**	**1.82**	**1.6**
	Existing Catalogue (2017)		1.77	1.66	1.46
Indonesia data	PPA data[1]	2.06			
	Feed-in Tariff, own calculation[2]		1.32 – 1.97*		
	ESDM[3]		2.24		
	IRENA (Other Asia)[4]	1.56			
International data	Danish technology catalogue**		1.81	1.72	1.67
	NREL ATB		4.00	3.85	3.44
	IEA Bioenergy (Task 32)		2.70	2.60	2.60
Projection	Learning curve – 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*

** *The catalogue reports values for CHP plants. Assuming a backpressure ratio of 0.15, a condensing equivalent is here calculated based on a full-plant electric efficiency of 31%.*

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.
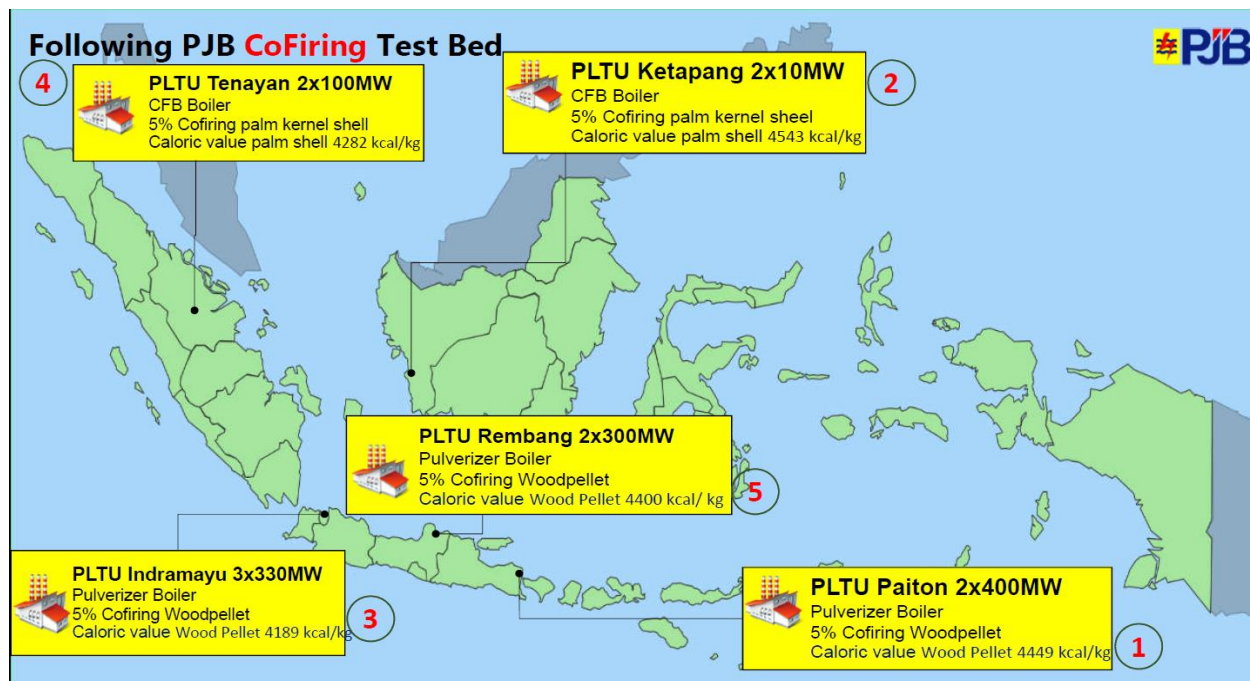
Co-firing projects of PT Pembangkitan Jawa Bali, PLN in 2019 and 2020

The proportion of biomass for co-firing coal power plants will be gradually increased from 1% to 5%. This is equivalent to 202 – 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 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.

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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 2019. 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 (smal plant - palm oil / rice husk)								
	2020	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
				Lower	**Upper**	**Lower**	**Upper**		
Energy/technical data									
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	7	7	5	9	5	9	A	1
Planned outage (weeks per year)	6	6	6	5	8	5	8	A	1
Technical lifetime (years)	25	25	25	19	31	19	31	A	8,10
Construction time (years)	2	2	2	2	3	2	3	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	0.0	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$_2$O (g per GJ fuel)	1.1	1.1	1.1						3
Financial data									
Nominal investment (M$/MWe)	2.00	1.82	1.60	1.30	2.25	1.2	2.0	B,C	4-8,11
- of which equipment	65	65	65	50	85	50	85		1,2
- of which installation	35	35	35	15	50	15	50		1,2
Fixed O&M ($/MWe/year)	47 600	43 800	38 100	35 700	59 500	28 600	47 600	A	4,5,8,11
Variable O&M ($/MWh)	3.0	2.8	2.4	2.3	3.8	1.8	3.0	A	5,11
Start-up costs ($/MWe/start-up)									

References:

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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 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.

12. MUNICIPAL SOLID WASTE AND LAND-FILL 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.
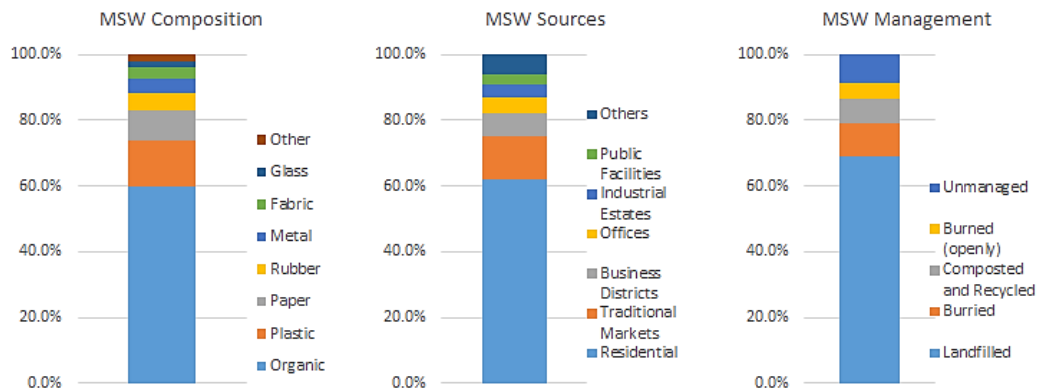
Indonesia's Municipal Solid Waste composition, source and handling statistics (Ministry of Environment and Forestry, 2017).

Based on solid waste management national policy and strategy target 2017–2025, Indonesia has 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 that the waste volume will be 30% left.

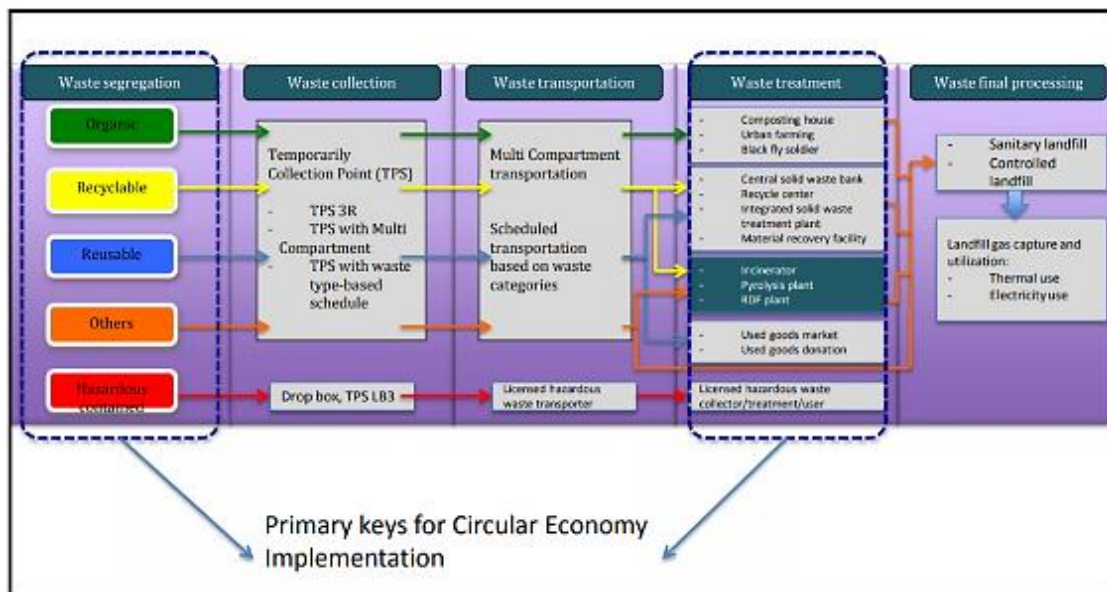*Business Process of Waste Handling*

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).
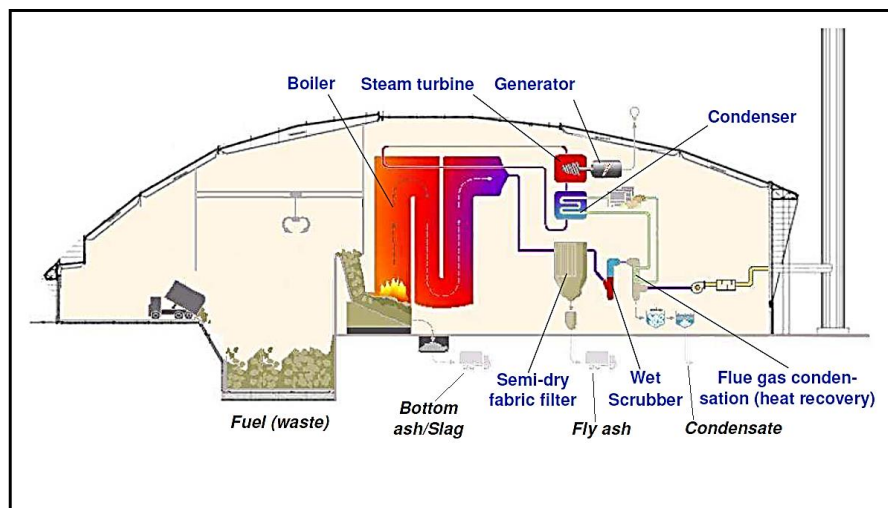
Typical Waste to Energy Plant (Nordic Heat of Sweden, 2017)

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 wastes 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.
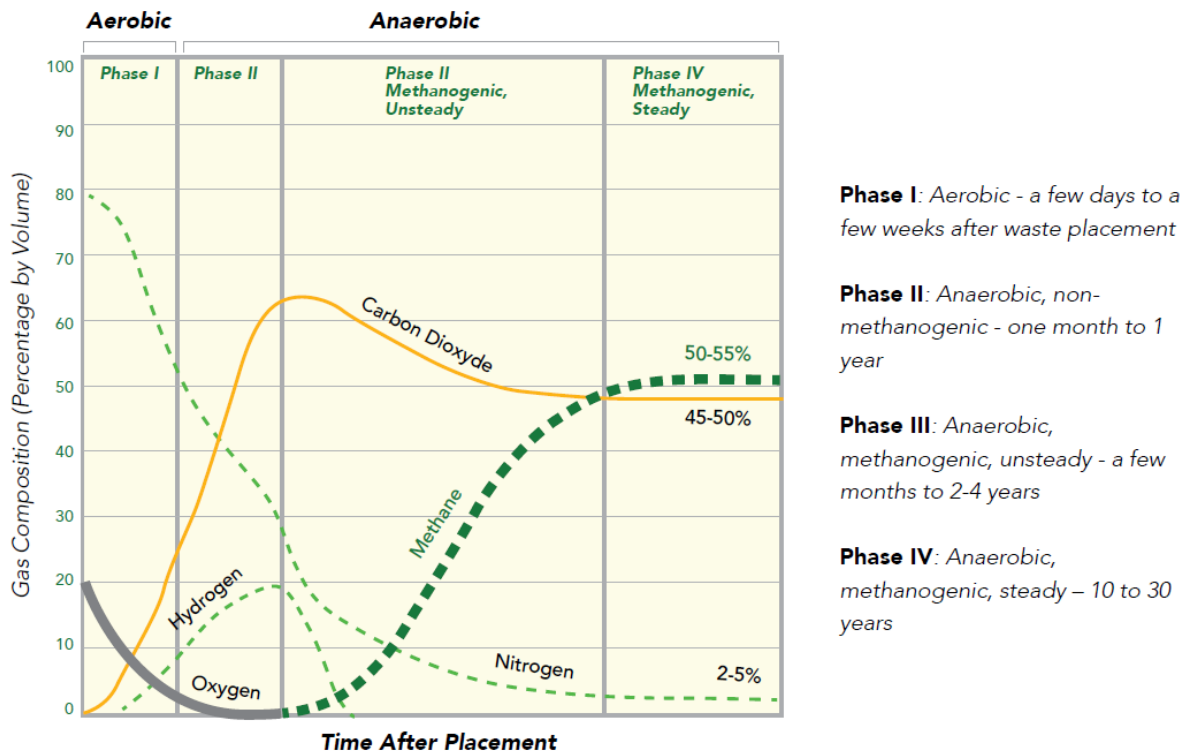
LFG generation and changes over time (Source: MEMR (2020), Waste to Energy Guidebook).

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Using gas engines, land-fill gas can be used as fuel feedstock to produce electricity. The production volume of land-fill gas from the same sites can have a range of 2-16 m^3/day.
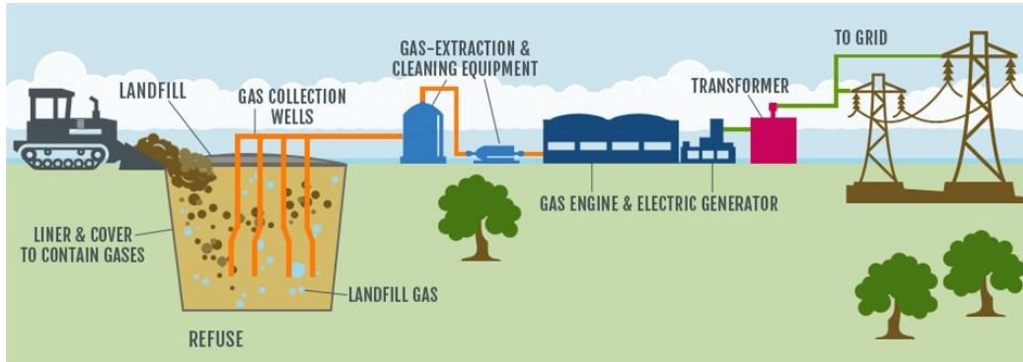
Land-fill gas to energy (ref. 5)

Based on a Ministry of Energy and Mineral Resources statistic, total land-fill gas (LGF) power plant potential in Indonesia is 535 MW, due to the fact that the majority of the land-fills 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 two land-fill gas power plants in operation currently 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.

Summary of waste to energy technologies' suitability per waste stream and potential output (ref. 4)

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

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.

Land-fill gas is the fuel feedstock for the land-fill 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 (m³/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 require 53% more feedstock compare 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 land-fill gas systems, the outputs are electricity and heat. The land-fill 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.

Land-fill gas to energy plants can also be ramped up or down depending on the availability of the land-fill 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 for 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 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 may 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)
Land-fill 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)
Land-fill 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 (twelve) 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 (SO2)	50

Nitrogen (NO and NO2)	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 ton of MSW per day. This RDF plant applies biodrying technology to process the waste. The resulted products are RDF fluff.

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12. Texas Comptroller of Public Accounts, 2008. "The Energy Report 2008: Chapter 18 Municipal Solid Waste Combustion." Texas Comptroller of Public Accounts.
13. PT Godang Tua Jaya, Jakarta, Indonesia 2017.

14. Jun Dong, Harish Kumar Jeswani, Ange Nzihou, Adisa Azapagic, The environmental cost of recovering energy from municipal solid waste, Applied Energy Volume 267, 1 June 2020.

Data sheets

The following pages contain the data sheets of the technology. All costs are stated in U.S. dollars (USD), price year 2019. 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								
	2020	**2030**	**2050**	**Uncertainty (2020)**		**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%	26%	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	10	10	7.5	12.5	7.5	12.5	C	1
Minimum load (% of full load)	20	20	20	15.0	25.0	15.0	25.0	C	1
Warm start-up time (hours)	0.5	0.5	0.5	0.4	0.6	0.4	0.6	C	1
Cold start-up time (hours)	2	2	2	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$_2$O (g per GJ fuel)									
Financial data									
Nominal investment (million $/MWe)	6.8	6.3	5.6	5.1	7.0	4.2	7.0	C	1
- of which equipment	4.0	3.4	2.8	3.0	3.5	2.1	3.5		1
- of which installation	2.8	2.9	2.8	2.1	3.5	2.1	3.5		1
Fixed O&M ($/MWe/year)	243 700	224 800	193 500	195 000	304 600	154 800	241 900	C	1
Variable O&M ($/MWh)	24.1	23.4	22.6	18.1	30.2	16.9	28.2	C	1
Start-up costs ($/MWe/start-up)									
Technology specific data									
Waste treatment capacity (tonnes/h)	27.7	27.7	27.7						B

References:

1 Danish Technology Catalogue "Technology Data for Energy Plants, Danish Energy Agency 2107- update in progress

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 The investment cost is based on waste to energy CHP plant in Denmark, according to Ref 1. A waste treatment capacity of 27,7 tonnes/h is assumed and an energy content of 10,4 GJ/ton. The specific finalcial data is adjusted to reflect that the plant in Indonesia runs in condensing mode and hence the electric capacity (MWe) is higher than for 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	Landfill Gas Power Plant - Municipal Solid Waste								
	2020	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
				Lower	Upper	Lower	Upper		
Energy/technical data									
Generating capacity for one unit (MWe)	1	1	1	0.5	10	0.5	10		1
Generating capacity for total power plant (MWe)	1	1	1	0.5	10	0.5	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		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$_2$O (g per GJ fuel)									
Financial data									
Nominal investment (M$/MWe)	2.5	2.5	2.5	2.3	2.8	2.3	2.9	A	3
- of which equipment	0.7	0.7	0.7	0.7	0.8	0.7	0.8		5
- of which installation	0.3	0.3	0.3	0.3	0.3	0.3	0.3		5
Fixed O&M ($/MWe/year)	125 000	125 000	125 000	113 640.0	137 500.0	113 636.4	143 750.0	A	3
Variable O&M ($/MWh)	13.5	13.5	13.5	10.1	16.9	10.1	16.9		
Start-up costs ($/MWe/start-up)									
Technology specific data									

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 PLN, 2017, data provided the System Planning Division at PLN

5 MEMR, 2015, "Waste to Energy Guidebook", Jakarta, Indonesia.

Notes:

A Uncertainty (Upper/Lower) is estimated as +/- 10-15%.

13. 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 of 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 land-fill. Some of the biomass potential can be converted to biogas. MSW and land-fill 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 Reactor (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.
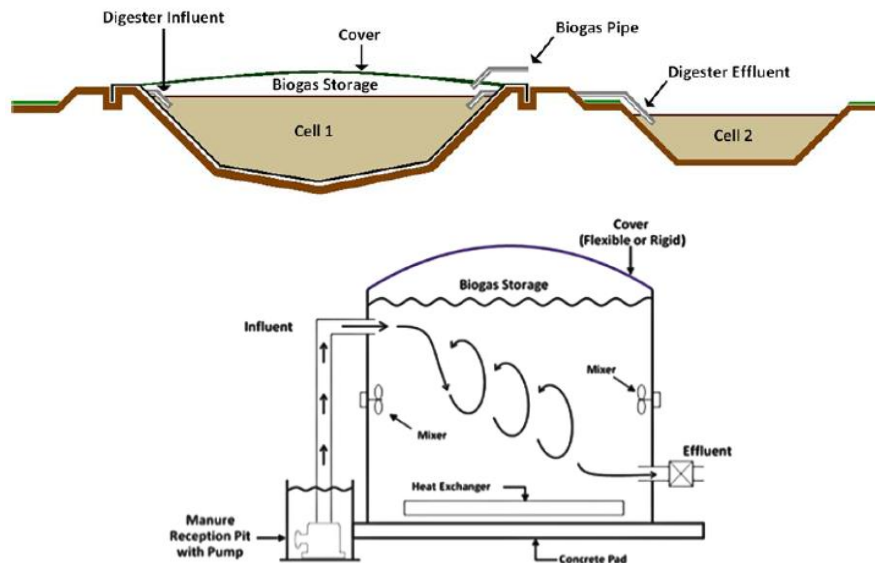
*Covered lagoon and CSTR biogas plants (ref.3)*

Covered lagoon systems are applied for which the 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 for 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 go up to 80% if the plant is operated as combined heat and power (CHP).
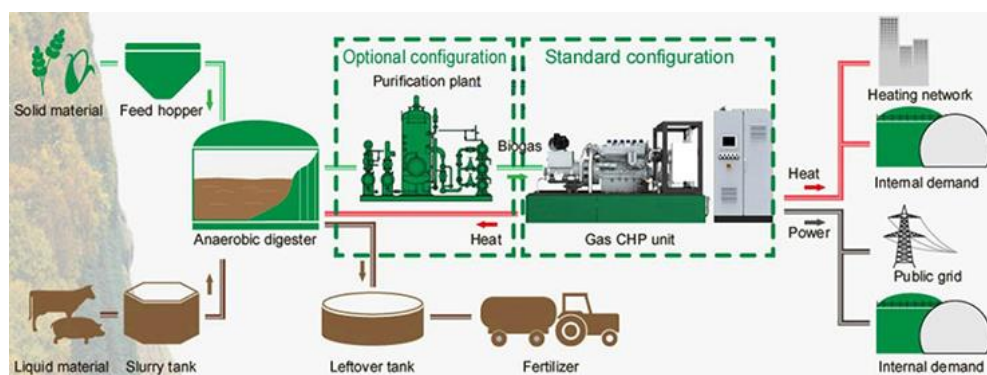
Biogas CHP working diagram (ref. 5)

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 assume 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 better 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 anaerobic treated organic waste product is almost free compared to raw organic waste.

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 waste water 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, or "genset," 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

Like 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 amount 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 catalogue the investment cost figures are based on recent PPAs/tariffs in Indonesia.

Kpxguvogpv "₄ₑ₄ₒ¥u"] O		423:	4242	4252	4272
Catalogues	**New Catalogue (2020)**		**2.15**	**1.82**	**1.6**
	Existing Catalogue (2017)		2.91	2.70	2.29
Indonesia data	PPA data[1]	2.03			
	Feed-in Tariff, own calculation[2]		1.57 - 2.15[*]		
	ESDM[3]		2.15		
International data	Danish technology catalogue		1.06	1.01	0.95
	NREL ATB		4.00	3.85	3.44
	IEA Bioenergy (Task 32)		2.70	2.60	2.60
Projection	Learning curve – 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)*

[*] *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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The following sources are used:

1. Jorgensen, 2009. *Biogas – green energy*, Faculty of Agricultural Sciences, Aarhus University, 2nd edition, Denmark
2. RENAC. *Biogas Technology and Biomass*, Renewables Academy (RENAC) AG, Berlin, Germany.
3. IIEE, 2015. "User guide for Bioenergy Sector", *Indonesia 2050 Pathway Calculator*, Jakarta, Indonesia.
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11. Industry Week. http://www.industryweek.com/energy/worlds-largest-biogas-plant-inaugurated-finland. Accessed 1st August 2017.
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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 2019. 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								
	2020	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
				Lower	Upper	Lower	Upper		
Energy/technical data									
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$/MWe)	2.15	1.96	1.72	1.55	2.15	1.3	2.2	B	3,5,8,9
- of which equipment	65	65	65	50	85	50	85		
- of which installation	35	35	35	15	50	15	50		
Fixed O&M ($/MWe/year)	97 000	89 200	77 600	72 800	121 300	58 200	97 000	A	5,7,9
Variable O&M ($/MWh)	0.11	0.1	0.1	0.1	0.1	0.1	0.1	A	6,9
Start-up costs ($/MWe/start-up)									

References:

1 PLN, 2017, data provided the System Planning Division at PLN

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".

8 PKPPIM, 2014, "Analisis biaya dan manfaat pembiayaan investasi limbah menjadi energi melalui kredit program", Center for Climate Change and Multilateral Policy Ministry of Finance Indonesia.

9 Learning curve approach for the development of financial parameters.

10 Vuorinen, A., 2008, "Planning of Optimal Power Systems".

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 uncertainty 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.

14. 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 Stated Policies and Sustainable Development scenarios 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 mill. 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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7. BWSC once again to deliver highly efficient power plant in the Faeroe 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 2019. 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	Diesel engine (using fuel oil)								
	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	20	20	20						1
Generating capacity for total power plant (MWe)	100	100	100						1
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)	1.0	1.0	1.0						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)	6.0	6.0	6.0					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$_2$ (degree of desulphuring, %)	0	0	0					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$_2$O (g per GJ fuel)									
Financial data									
Nominal investment (M$/MWe)	0.80	0.80	0.78	0.70	0.90	0.65	0.85	D	6.7
- of which equipment									
- of which installation									
Fixed O&M ($/MWe/year)	8,000	8,000	7,760						2
Variable O&M ($/MWh)	6.4	6.0	5.8						2
Start-up costs ($/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, 2017, 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 exhaust 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.

15. 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.
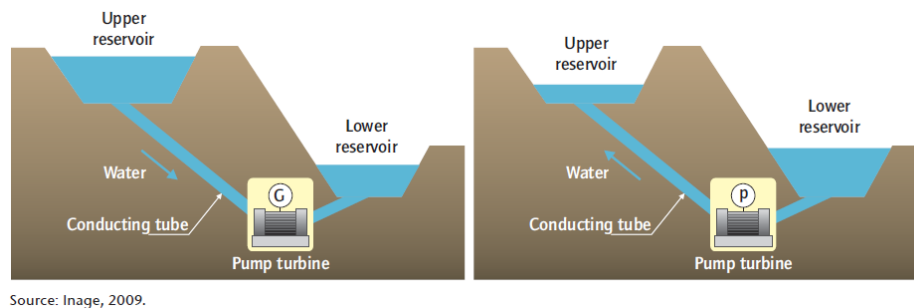
Pumped storage hydropower plants (ref. 2)

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 schemes.

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).

Indonesia is currently developing a pumped storage hydropower plant project at 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 2015 and the first generator will be commissioned in 2019. 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 (ref. 7).

Input
Electricity

Output
Electricity

Typical capacities
50 to 500 MW per unit (ref. 12)

Ramping configurations
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:
- Lower cost compared to other peak load plants (gas and diesel power plants).
- 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 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 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.
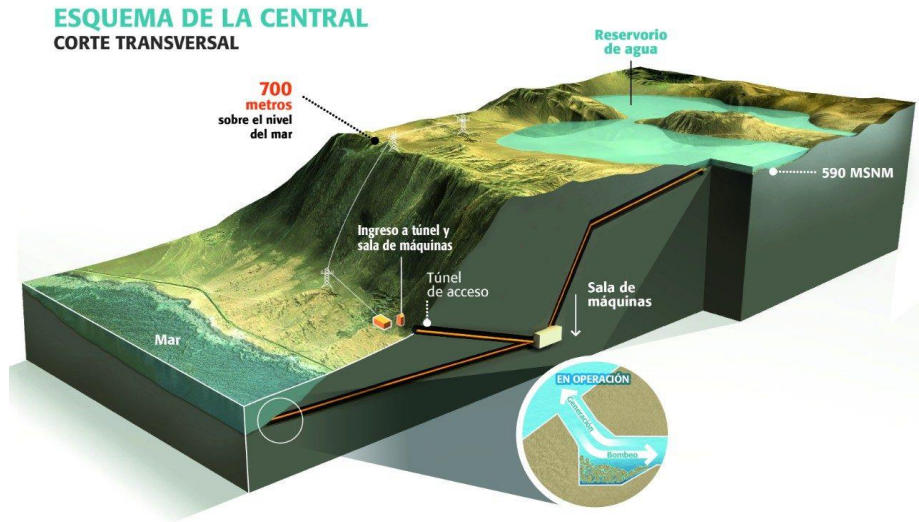
A 300 MW sea water pumped storage hydropower plant in Chile (ref. 13)

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.
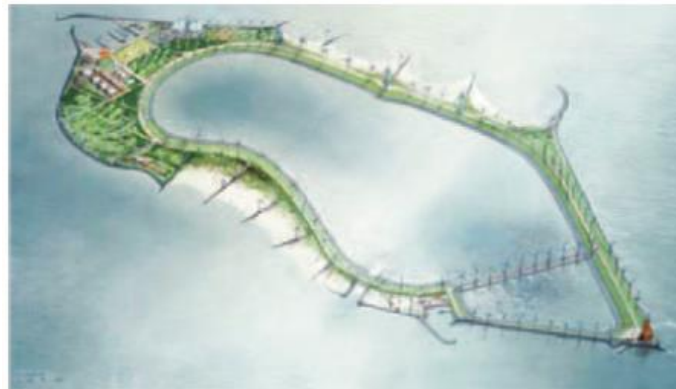
Concept of an energy island (ref. 9)

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

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).

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).

As mentioned before Indonesia is building the country's first pumped storage hydropower plant. The power plant will operate by shifting water between two reservoirs; the lower reservoir on the Upper Cisokan River and the upper reservoir on the Cirumamis River which is a right-bank tributary of the Upper Cisokan. When energy demand is high, water from the upper reservoir is sent to the power plant to produce electricity. When energy demand is low, water is pumped from the lower reservoir to the upper by the same pump-generators. This process repeats as needed and allows the plant to serve as a peaking power plant. 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. It is expected that the plant will be commercially operational in 2024.

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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 2019. 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 pumped storage		
	2020	**2030**	**2050**	\multicolumn{2}{c}{**Uncertainty (2020)**}	\multicolumn{2}{c}{**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)	50	50	50	40	90	40	90		1
Construction time (years)	4.3	4.3	4.3	2.2	6.5	2.2	6.5	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	-	-	-	-	-	-	-		
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$/MWe)	0.86	0.86	0.86	0.60	6.0	0.60	6.0	C,E	1,3,4
- of which equipment (%)	30%	30%	30%	20%	50%	20%	50%		7
- of which installation (%)	70%	70%	70%	50%	80%	50%	80%		7
Fixed O&M ($/MWe/year)	8 000	8 000	8 000	4 000	30 000	4 000	30 000		3,4,6.7
Variable O&M ($/MWh)	1.3	1.3	1.3	0.5	3.0	0.5	3.0		1,7
Start-up costs ($/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
Load/unload time (hours)	10	10	10	4	12	4	12	D	1,6

References:

1 PLN, 2017, data provided the System Planning Division at PLN

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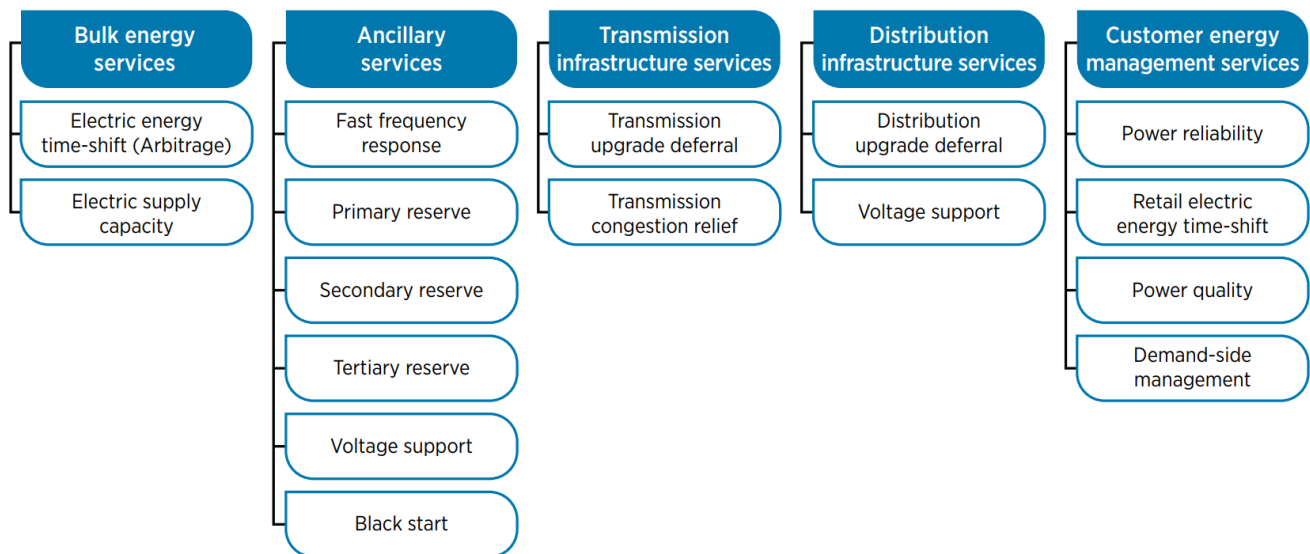7 IRENA, 2012, "Renewable Energy Technologies: Cost Analysis Series - Hydropower".

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.

16. ELECTROCHEMICAL STORAGE

Brief technology description

With increasing shares of variable renewable energy in power systems, the role of electricity storage grows in importance. Among all technologies, electrochemical storage (batteries) has 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.

Bulk energy services	Ancillary services	Transmission infrastructure services	Distribution infrastructure services	Customer energy management services
Electric energy time-shift (Arbitrage)	Fast frequency response	Transmission upgrade deferral	Distribution upgrade deferral	Power reliability
Electric supply capacity	Primary reserve	Transmission congestion relief	Voltage support	Retail electric energy time-shift
	Secondary reserve			Power quality
	Tertiary reserve			Demand-side management
	Voltage support			
	Black start			

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.

U.S. utilty-scale battery installations (2003-2018)
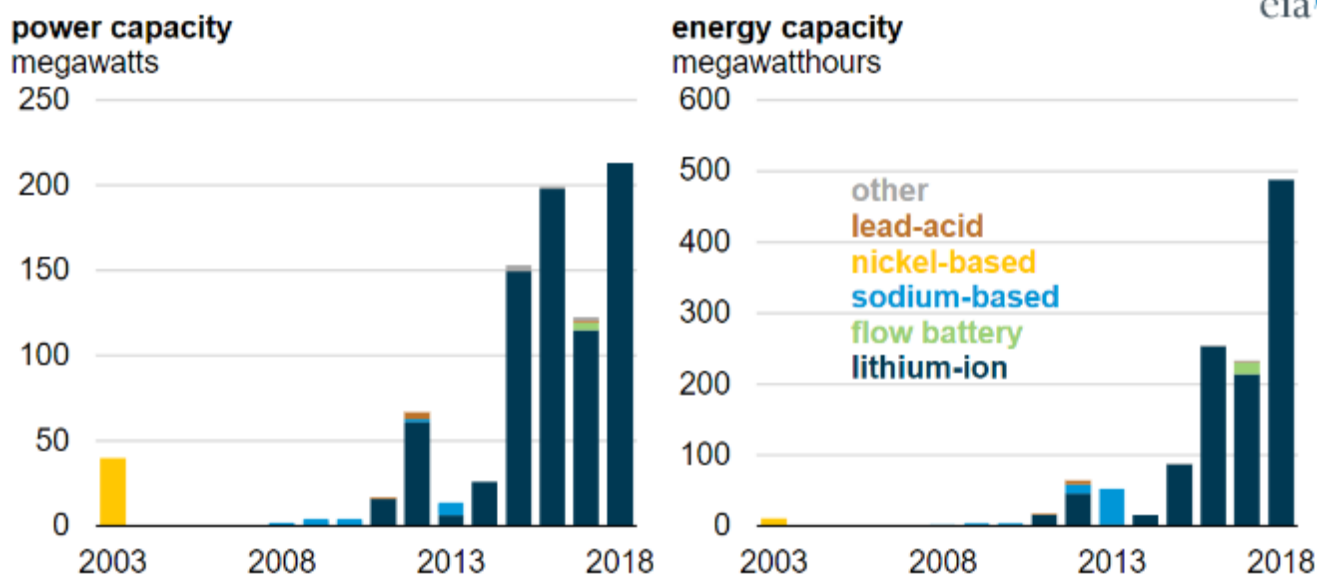
*Utility-scale battery installations by type in the US (2003-18). Source: EIA.*

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 unit's footprint can be assumed to be 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 depends 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.
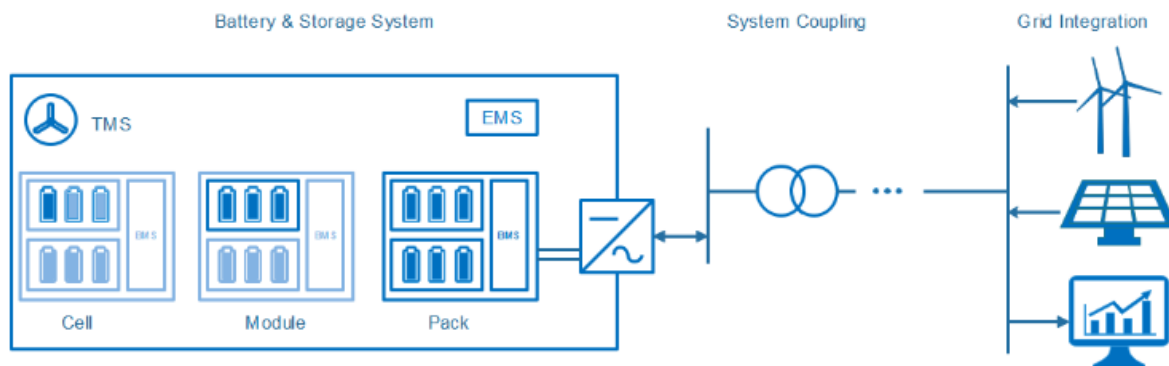
Schematic illustration of a battery storage system and its grid connection.

Charging and discharging rates of LIB are often measured with the C-rate, which is the maximum current the battery can deliver with respect to its volume. For example, if a battery is discharged in 20 minutes, 1 hour and 2 hours then it has C-rates of 3C, C and C/2 respectively. 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.
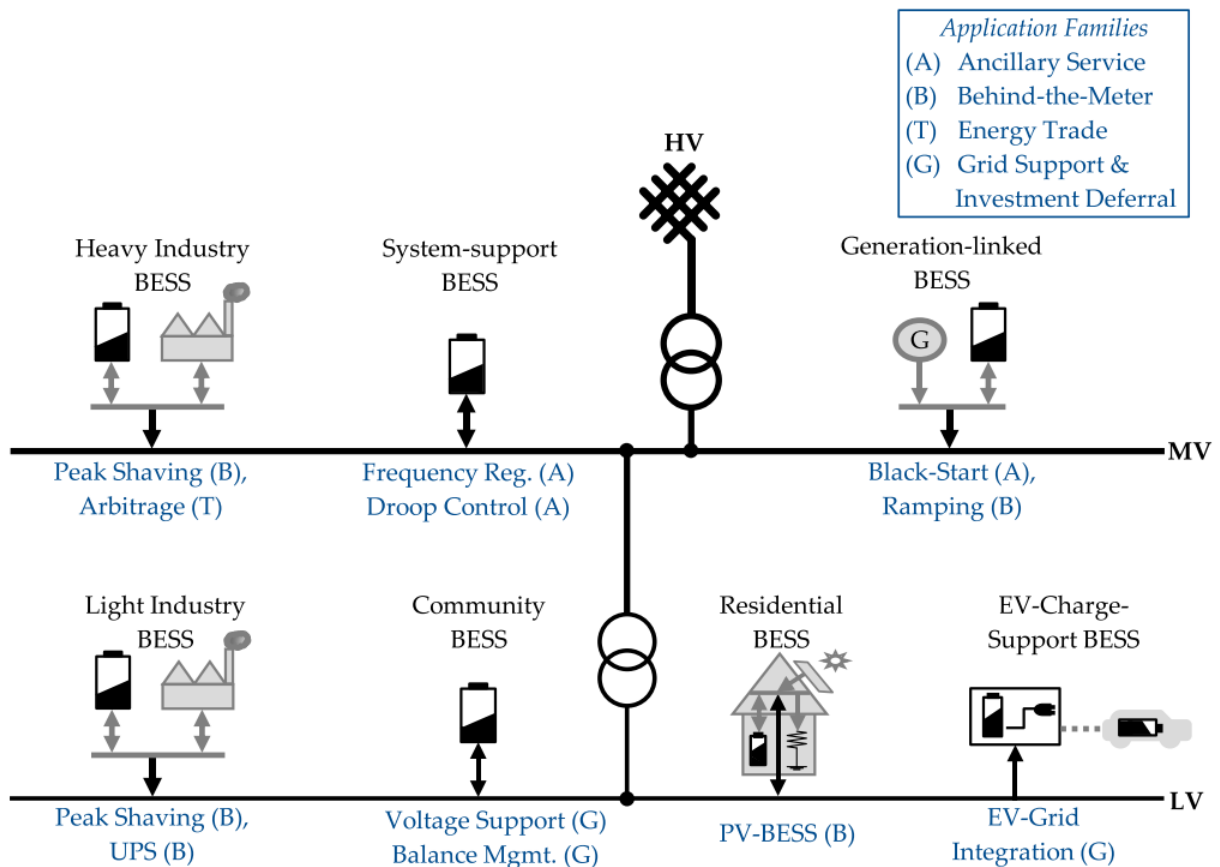
Different uses of battery systems depending on voltage level and application families (ref. 43).

Input
Electricity.

Output
Electricity.

The efficiency of Li-ion battery cells is close to 100%. However, there exist 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% nowadays. Frequency regulation requires fast short-cycle charge-discharge and reduces round-trip efficiency. Extensive cycling reduces the lifetime of batteries. Overall, the round-trip efficiency can be expressed as a decreasing function of the C-rate, that is how much current is released by the battery compared to its' rated storage capacity.

Typical capacities
For bulk energy services, Li-Ion batteries come in large sizes. Small batteries are in the order of 1 to 10 MW/MWh, but can reach several hundreds of MW/MWh. For example, the Hornsdale facility in Australia has 100MW/129MWh capacity/energy components and a further expansion of 50MW/64.5MWh is in the pipeline. 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 very flexible in terms of power/energy capacity and time of discharge. This type of batteries 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 relatively small 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

In the IEA's 2019 World Energy Outlook, battery installations are forecast to provide 330 GW and 550 GW of system flexibility in 2040 in the Stated Policies and the Sustainable Development Scenarios respectively. India will be one of the leading markets. Given a 2018 cumulative capacity of 8 GW, this returns ~8 capacity doublings in 22 years.

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.

The historical and projected prices for Li-Ion batteries are shown in the figure below, as forecast by Bloomberg. A battery pack is expected to cost 62 USD/kWh in 2030 with the assumption of an 18% learning rate. The IEA's 2019 World Energy Outlook foresees that the total battery system costs will drop to well-below 200 USD/kWh by 2040. Cost reductions are much more significant for the battery pack than for the entire BESS, as power electronics' development is expected to be more moderate. Price drops for the single components of a BESS (battery pack, DC-AC conversion, management systems) are heavily influenced by the potential market applications, which drive R&D efforts and advancements in the manufacturing process.

Lithium-ion battery price outlook

Lithium-ion battery pack price (real 2018 $/kWh)
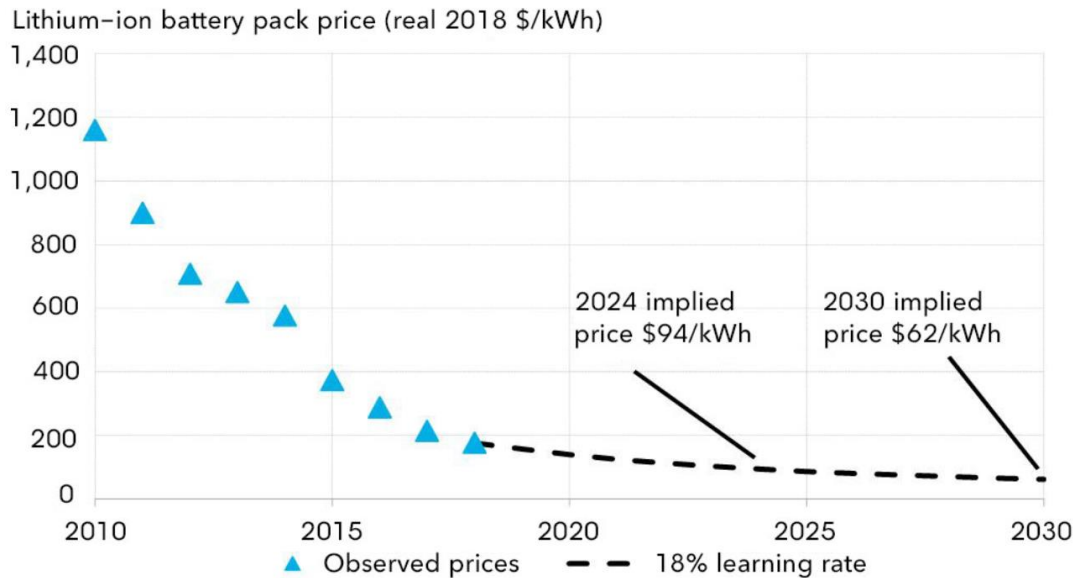
Li-Ion battery pack price projections. Source: Bloomberg NEF.

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 report estimates O&M costs to lie in a wide range (0.3-5 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.

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.

Investment costs [MUSD_{2019}/MW]	2018	2020	2030	2050
New Catalogue (2020)		0.76	0.43	0.20
Existing Catalogue (2017)				

Danish technology catalogue		0.76	0.43	0.20
NREL ATB		0.86	0.48	0.36
Lazard	0.63			

Note: values for 2-hour storage.

Uncertainty in future data

Development in LIB has been rapid in the last few years 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 the IEA, at the end of 2018 8 GW of battery capacity were installed worldwide, with 3 GW added only in 2018 (the figure includes all types of batteries)[4]. 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.

- Hornsdale TESLA battery in Australia. 129MWh/100MW, with an expansion in the pipeline of additional 64.5MWh/50MW. 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.

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[4] A world map with storage installations by storage type can be found at the following link: https://public.tableau.com/shared/YFTR6XFTD?:showVizHome=no&:embed=true. Last accessed: September 2020.

The 40 MW and 40 MWh energy storage system in Fukushima, Japan.

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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 2019. 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)								
	2020	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
				Lower	**Upper**	**Lower**	**Upper**		
Energy/technical data									
Energy storage capacity for one unit (MWh)	6.0	7.0	8.0					A,B	1,2
Energy/Power ratio (hours)	1.04	2.08	4.16					E	1,2
Discharge time (hours)	1.00	2.00	4.00					E	1,2
Round-trip efficiency (%) AC	91	92	92					C	3,12
Round-trip efficiency (%) DC	95	96	96					C	3,12
Self-discharge rate (%/day)	0.10	0.10	0.10						4
Forced outage (%)	0.38	0.35	0.25					M	
Planned outage (weeks per year)	0.20	0.10	0.10					L	
Technical lifetime (cycles)	10000	15000	20000					M	5
Technical lifetime (years)	20	25	30					D	
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						6
Financial data									
Nominal investment (MUSD/MWh)	0.578	0.264	0.157	0.455	0.920	0.075	0.398	G	13
- energy component (MUSD/MWh)	0.152	0.062	0.035	0.080	0.215	0.030	0.131		7,8
- power component (MUSD/MW)	0.311	0.184	0.069	0.273	0.580	0.045	0.284	H	9,10,11
- other project costs (MUSD/MWh)	0.115	0.110	0.105	0.102	0.125	0.023	0.125	N	9,12
Fixed O&M (USD/MWh/year)	621	311	155	500	650	250	350		12
Variable O&M (USD/MWh)	2.30	2.07	1.84	0.45	6.36	0.34	2.84	I	10
Technology specific data									
Energy storage expansion cost (MUSD/MWh)	0.267	0.163	0.086	0.182	0.294	0.052	0.200	B,F	7,8
Output capacity expansion cost (MUSD/MW)	0.311	0.184	0.069	0.273	0.580	0.045	0.284	B,F	9,10,11

Notes:

A One unit defined as a 40 feet container including LIB system and excluding power conversion system. Values are taken from Samsung SDI brochures for grid-connected LIBs from 2016 and 2018 [2,14]. Units with C-rates below/above 1 are possible, depending on the system needs and cost of the energy and power rating components. A C-rate of 1 is here assumed for 2020, as it is close to several new installations.

B Power and energy output can be scaled linearly by utilizing many modules (up to 100MW has been demonstrated). Output capacity expansion can be done reprogramming the management unit without any new battery module.

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/2 to 3C. 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

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. Cycle lives are steadily increasing over last few years as reflected in 2020/2030 numbers [4,5,14].

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.

Examples for calculation of CAPEX using datasheet:

1. Frequency regulation in 2020: 4C-rate, 2 MWh BESS system. 20 years operation time.
Cost items:
2 MWh "energy component", year 2020
2 MWh "other project costs", year 2020
4C = 0.25-hour discharge time $\Rightarrow$ 8 MW "power component", year 2020

CAPEX: 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 $\Rightarrow$ 4 MW "power component", year 2030

CAPEX: 16 * (0.062 M\$ + 0.11 M\$) + 4 * 0.184 M\$ = 3.488 M\$

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. Tabel di bawah merangkum peraturan tersebut. Persyaratan tingkat kandungan dalam negeri (TKDN) adalah jumlah pekerjaan dan/atau sumber daya yang harus diterapkan di Indonesia

Rangkuman Peraturan mengenai kandungan dalam negeri.

Jenis	Kapasitas	Tingkat Kandungan Dalam Negeri (%)		
		Barang (minimum)	Jasa	Kombinasi Barang dan Jasa (minimum)
PLTU	Kurang dari 15 MW	67.95	96.31	70.79
	15 – 25 MW	45.36	91.99	49.09
	25 – 100 MW	40.85	88.07	44.14
	100 – 600 MW	38.00	71.33	40.00
	> 600 MW	36.10	71.33	38.21
PLTA	Kurang dari 15 MW	64.20	86.06	70.76
	15 – 50 MW	49.84	55.54	51.60
	50 – 150 MW	48.11	51.10	49.00
	> 150 MW	47.82	46.98	47.60
PLTP	Kurang dari 15 MW	31.30	89.18	42.00
	5 – 10 MW	21.00	82.30	40.45
	10 – 60 MW	15.70	74.10	33.24
	60 – 110 MW	16.30	60.10	29.21
	> 110 MW	16.00	58.40	28.95

PLTG	Kurang dari 100 MW	43.69	96.31	48.96
PLTGU	Up to 50 MW	40.00	71.53	47.88
	50 – 100 MW	35.71	71.53	40.00
	100 – 300 MW	30.67	71.53	34.76
	> 300 MW	25.63	71.53	30.22
PLTS	Tersebar off-grid	39.87	100.00	45.90
	Terpusat off-grid	37.47	100.00	43.72
	Terpusat on-grid	34.09	100.00	40.68

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 2020 (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.

Kategori 1. Teknologi yang masih dalam tahap penelitian dan pengembangan. Ketidakpastian terkait harga dan kinerja hari ini dan masa yang akan datang, sangat signifikan.

Kategori 2. 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).

Kategori 3. 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).
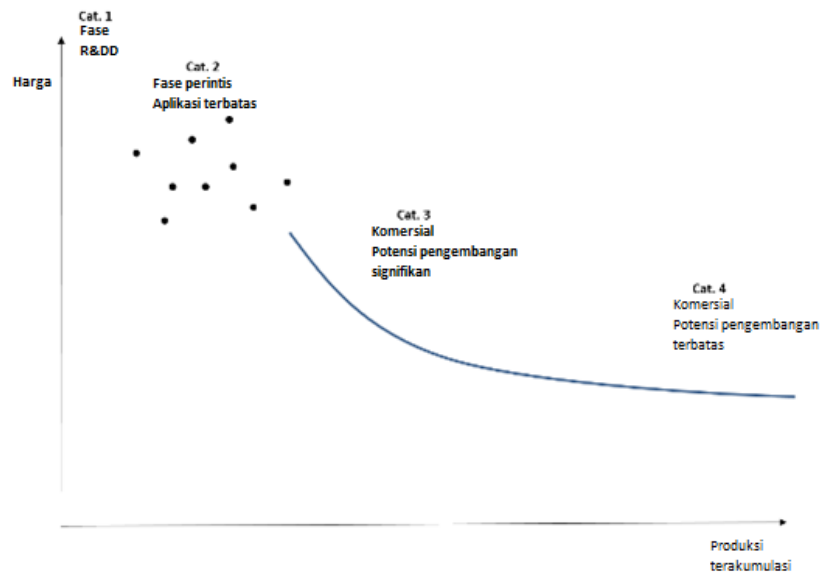
Tahap pengembangan teknologi. Korelasi antara akumulasi volume produksi (MW) dan harga.

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 (lihat Lampiran untuk pembahasan lebih rinci). Pembelajaran teknologi didasarkan pada kecepatan pembelajaran tertentu dan pada penerapan kapasitas yang didefinisikan sebagai rata-rata dari IEA's Stated Policies and Sustainable Development. 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]		2018	2020	2030	2050
Katalog	Katalog baru (2020)				
	Katalog lama (2017)				
Data Indonesia	Data lokal I				
	Data lokal II				
Data Internasional	Katalog teknologi Denmark				
	IRENA				
	IEA WEO 19				
Proyeksi	Kurva pembelajaran – tren biaya [%]				

Sedangkan untuk data ketidakpastian biaya investasi, pendekatan berikut diikuti: untuk tahun 2020 batas bawah dan batas atas ketidakpastian berasal dari rentang biaya di berbagai sumber yang dianalisis. Untuk tahun 2050, estimasi tengah didasarkan pada kecepatan pembelajaran 12,5% dan penyebaran kapasitas rata-rata dari skenario STEPS dan SDS dari World Energy Outlook 2019 (lihat Lampiran: prakiraan biaya teknologi produksi listrik). Rentang ketidakpastian 2050 menggabungkan rentang biaya tahun 2020 dengan ketidakpastian terkait penerapan teknologi dan pembelajaran: kisaran kecepatan pembelajaran 10-15% dan jalur penerapan kapasitas yang sesuai dari skenario STEPS dan SDS dianggap untuk mengevaluasi ketidakpastian tambahan. Batas atas biaya investasi, misalnya, akan dihitung sebagai batas atas untuk tahun 2020 ditambah pengembangan biaya berdasarkan skenario dengan kecepatan pembelajaran 10% dikombinasikan dengan skenario dengan penerapan terendah menjelang tahun 2050.

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

Untuk melakukan analisis komparatif diantara teknologi yang berbeda, sangat penting bahwa data tersebut sebenarnya bisa dibandingkan. Sebagai contoh, data ekonomi dinyatakan dalam tingkat harga yang sama dan pajak pertambahan nilai (PPN) atau pajak lainnya tidak termasuk. Alasannya adalah katalog teknologi itu harus mencerminkan biaya sosial ekonomi bagi masyarakat Indonesia. Dalam konteks ini, pajak tidak mewakili biaya sebenarnya melainkan suatu transfer modal antara pemangku kepentingan Indonesia, pengembang proyek dan pemerintah. Juga cukup penting apabila data diberikan untuk tahun yang sama. Tahun 2020 sebagai basis untuk teknologi terkini, yaitu teknologi terbaik yang tersedia pada saat komisioning.

Semua biaya dinyatakan dalam US dollar (USD), harga konstan tahun 2019. Ketidakpastian dikaitkan dengan parameter tertentu dan tidak dapat dibaca secara vertikal – artinya suatu produk dengan, misal efisiensi lebih rendah, tidak harus mempunyai harga lebih rendah juga. Ketika akan mengkonversi biaya dari suatu tahun X ke USD 2019, pendekatan berikut disarankan:

1. Jika biaya dinyatakan dalam IDR, konversikan ke USD dengan menggunakan nilai tukar untuk tahun X (tabel pertama di bawah).
2. Kemudian ubah dari USD pada tahun X menjadi USD di tahun 2019 dengan menggunakan hubungan antara Indeks Harga Produsen AS untuk "Manufaktur Peralatan Mesin, Turbin, dan Transmisi Pembangkit" tahun X dan 2019 (tabel kedua di bawah).

Kurs rata-rata tahunan
(sumber: Bank Dunia, 2020)

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

Indeks Harga Produsen AS untuk manufaktur mesin, turbin, dan transmisi tenaga listrik. Industri ini terdiri dari perusahaan yang bergerak di bidang pembuatan turbin, peralatan transmisi tenaga, dan mesin pembakaran dalam (kecuali bensin dan pesawat terbang otomotif), "Sistem Klasifikasi Industri Amerika Utara, Amerika Serikat, 2017" hal. 258 dan Biro Statistik Tenaga Kerja AS, Nomor Seri: PCU333611333611)

Tahun	Indeks Harga Produsen
2007	152.6
2008	162.9
2009	174.6
2010	174.6
2011	177.7
2012	179.0
2013	180.9
2014	183.0
2015	184.6
2016	181.8
2017	181.8
2018	184.2
2019	189.0

Waktu konstruksi, yang juga ditentukan dalam lembar data, menyatakan waktu antara ketika pembiayaan sudah terjamin, serta semua perizinan sudah ditangan, dan waktu komisioning.

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 2020 dan 2050 dan untuk parameter tekno ekonomi terpilih (data keuangan, data kinerja utama). Tingkat ketidakpastian digambarkan dengan memberikan batas bawah dan atas yang mengindikasikan suatu interval konfiden 90%. 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. Alasannya adalah, standar pasar untuk pembangkit batubara di Indonesia tidak jelas.

Tingkat ketidakpastian hanya dinyatakan untuk nilai paling kritis seperti biaya investasi dan efisiensi.

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								
	2020	2030	2050	Ketidakpastian (2020)		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 (jam)									
Waktu cold start-up (jam)									
Lingkungan									
PM 2.5 (gram per Nm^3)									
SO$_2$ (derajat desulfurisasi, %)									
NO$_X$ (g per GJ bahan bakar)									
CH$_4$ (g per GJ bahan bakar)									
N$_2$O (g per GJ bahan bakar)									
Data keuangan									
Investasi nominal (M$/MWe)									
- bagian peralatan									
- bagian instalasi									
O&M tetap ($/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 dalam US Dollar harga konstan 2019 dan tidak termasuk pajak pertambahan nilai (PPN) atau pajak lainnya.

Untuk proyeksi, biaya keuangan masa yang akan datang ada tiga pendekatan keseluruhan. Terdapat beberapa pendekatan untuk mengestimasi biaya teknologi pembangkitan di masa depan. Katalog ini menggunakan pendekatan kurva pembelajaran (learning curve). Metode ini terbukti kokoh secara historis dan nilai estimasi laju pembelajaran dapat diperoleh untuk hampir semua teknologi. Ea Energi Analyses telah menyiapkan catatan tersendiri dengan judul, "Prediksi biaya teknologi produksi listrik" berdasarkan pendekatan yang digunakan dalam katalog ini, ada di lampiran.

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:

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

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: FORECASTING THE COST OF ELECTRICITY PRODUCTION TECHNOLOGIES

Historic data shows that the cost of most electricity production technologies have decreased over time. It can be expected that further cost reductions and improvements of performance will also be realized in the future. Such trends are important to consider for future energy planning and therefore need to be taken into account in the technology catalogue.

Three main different approaches to forecasting are often applied:

1. **Engineering bottom-up assessment.** Detailed bottom-up assessment of how technology costs may be reduced through concrete measures, such as new materials, larger-scale fabrication, smarter manufacturing, module production etc. Costs are also influenced by the asset size, i.e. by the development of design parameters over time; for instance, how the design of a wind turbine is expected to evolve over time.
2. **Delphi-survey**. Survey among a very large group of international experts, exploring how they see costs developing and the major drivers for cost-reduction.
3. **Learning curves.** Projections are based on historic trends in cost reductions combined with estimates of future deployment of the technology. Learning curves express the idea that each time a unit of a particular technology is produced, some learning accumulates which leads to cheaper production of the next unit of that technology.

Each of the three approaches comes with advantages and disadvantages, which are summarised below.

	Advantages	Disadvantages
Engineering bottom-up	• Gives a good understanding of underlying cost-drivers. • Provides insight to how costs may be reduced.	• Requires information at a very detailed level. • Difficult to obtain objective (non-biased) information from the experts, who possess the best knowledge of a technology. • Potentially very time consuming.
Delphi-survey	• Input from a large number of experts improves robustness of forecast.	• Costly and time-consuming to carry out surveys. • Challenge to identify relevant and unbiased experts.
Learning curves	• Large number of studies have examined learning rates and documented that learning rates correlations are real. • The over-arching logic of learning rates has proved correct for many technologies and sectors. • Data available to perform learning curves for most important technologies.	• Does not explain why cost reductions take place. • One-factor learning rates are usually adopted, but in practice cost drivers included in the learning curves follow different developments. Multi-factor learning rates potentially make up for this issue, but they are difficult and time-consuming to obtain. • The theory assumes that each technology makes up an independent technology complex, but in practice there may be a significant overlap between different technologies, which makes the interpretation and use of learning curves more complicated. • Forecasting based on learning curves depend on the deployment level of the single technology, which is uncertain in the future.

Advantages and disadvantages of different methodologies for forecasting technology costs.

For the purpose of the present catalogue, the (one-factor) learning curve approach is the most suitable way forward. Firstly, the learning curve correlations are well documented; secondly, the risk of bias is reduced compared to the alternative approaches; thirdly, it does not involve costly and time-consuming surveys.

The results from the learning curves will be compared with projections from international literature. Learning-curve-based cost projections are dependent on two key inputs: a projection of the technological deployment and an estimated learning rate. Essentially, this is the only information required to perform cost projections.

Global demand for technologies

To estimate the future demand of each of the technologies we rely on analyses of the future global electricity supply from the International Energy Agency (IEA). Indeed, how the global demand and composition of electricity will develop is associated with a high level of uncertainty related to climate policy ambitions, costs and availability of fossil fuel resources and the development of existing and new electricity generation technologies.

In its latest Energy Technology Perspectives 2020 and World Energy Outlook 2019, the IEA considers two reference global pathways, the Stated Policy scenario and the Sustainable Development scenario, with varying degree of climate policy commitment:

- The **Stated Policies scenario (STEPS)** assesses the evolution of the global energy system on the assumption that government policies that have already been adopted or announced with respect to energy and the environment, including commitments made in the nationally determined contributions under the Paris Agreement, are implemented;

- The **Sustainable Development scenario (SDS)** describes the broad evolution of the energy sector that would be required to reach the key energy-related goals of the United Nations SDGs, including the climate goal of the Paris Agreement (SDG 13), universal access to modern energy by 2030 (SDG 7), and a dramatic reduction in energy-related air pollution and the associated impacts on public health (SDG 3.9) [8].
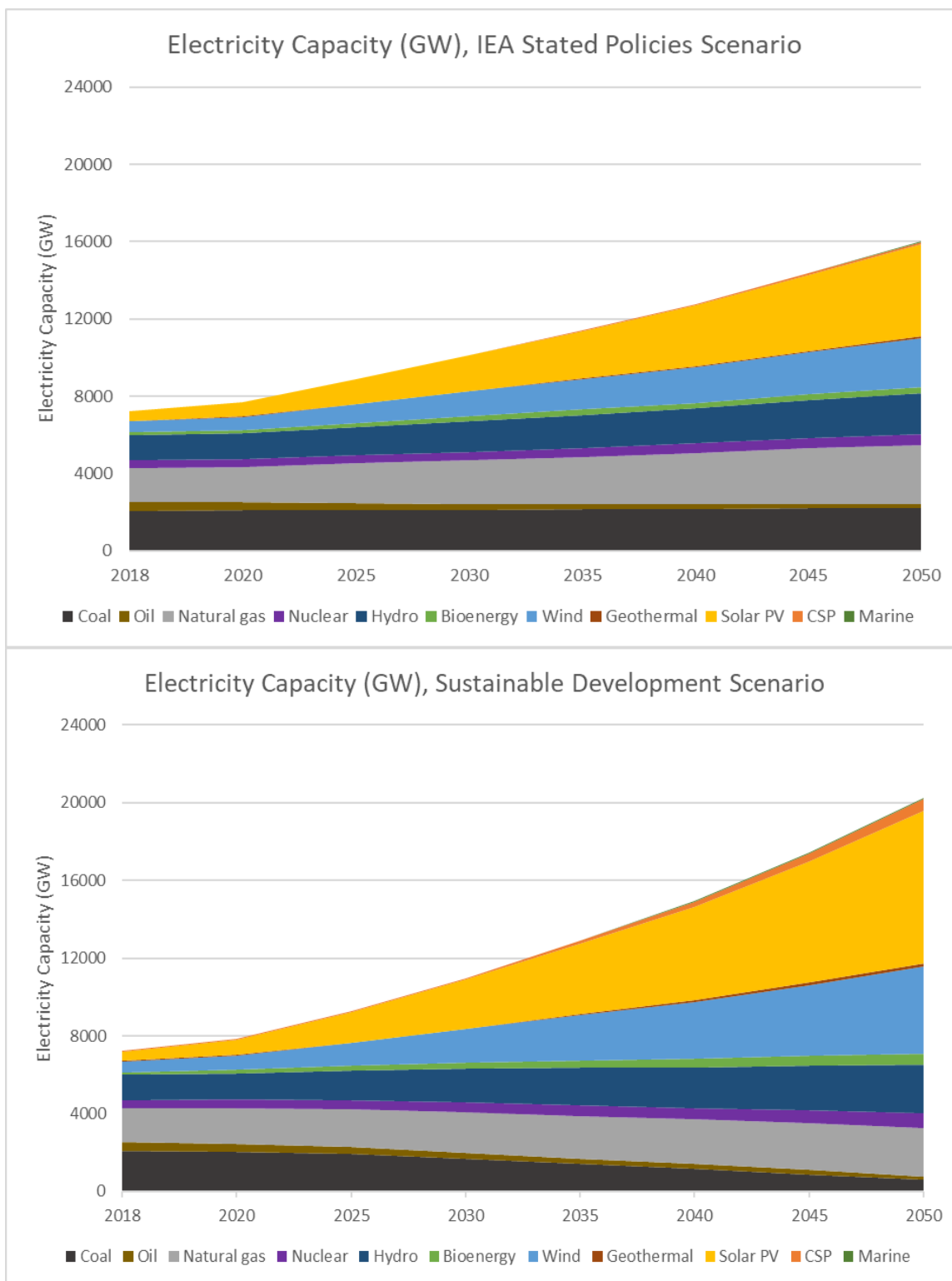
We use the two IEA scenarios to set a realistic framework for the future technology deployment.

According to IEA's World Energy Outlook 2019 data, it is projected that under the STEPS the electricity demand increases from 371 Mtoe in 2018 to 501 Mtoe in 2040. On the other hand, under the SDS demand for electricity will increase to 423 Mtoe, which is significantly less compared to STEPS. Clearly, an important factor behind the Sustainable Development scenario is a reduction in the rate of increase in demand, as a consequence of energy efficiency measures and reduced energy intensity. Moreover, looking at the projection by energy source, there is a slight reduction in the use of coal and oil under STEPS, whereas the reduction in usage of coal, oil and natural gas is much more significant in the Sustainable Development scenario. This development is further represented in the electricity capacity projections from 2018 to 2040. The IEA scenarios provide data only up to 2040. For the projections to be in line with this catalogue and provide information up to 2050, the data is calculated through forecasting of capacity added and retired from 2040 to 2050. Therefore, the projections between 2040-2050 are more uncertain.

The final projections of electricity generation capacity for 2018 to 2020 as per world energy outlook 2019 data and forecasting done are represented in the figures below. As can be seen, for SDS, the projections estimate a significant increase in renewables like solar and wind, and a reduced dependency on fossil fuels in order to meet the sustainable development goals. It can also be noted that the projected installed capacity in the SDS scenario

is higher compared to STEPS. This is due to the fact that technologies like wind and solar have lower capacity factors and therefore more capacity is needed to supply the same demand.

Electricity Capacity (GW), IEA Stated Policies Scenario

Legend: Coal, Oil, Natural gas, Nuclear, Hydro, Bioenergy, Wind, Geothermal, Solar PV, CSP, Marine

Electricity Capacity (GW), Sustainable Development Scenario

Legend: Coal, Oil, Natural gas, Nuclear, Hydro, Bioenergy, Wind, Geothermal, Solar PV, CSP, Marine

Electricity Capacity (GW) in the IEA's stated policies and sustainable development scenarios. IEA – World Energy Outlook 2019 [9].

The following tables show the development of accumulated capacities of different electricity generation technologies toward 2050, using 2020 as the starting point (=1). The accumulated figures represent total installations, taking into consideration the need for replacement of progressively decommissioned power plants over the period. Under STEPS it is seen that the only fossil fuel significantly reduced is oil. This implies that if on-going policies are followed, globally coal and natural gas will still make up a major share of the energy supply. However, under the SDS the projected increase of electricity capacity of wind is over three-fold, solar is over four-fold and CSP and marine technologies play a significantly greater role.

Accumulated generation capacities relative to 2020, in the STEPS scenario.

Accumulated generation capacity relative to 2020 (=1)	2030	2040	2050
Coal	1.12	1.28	1.41
Oil	1.06	1.12	1.18
Natural gas	1.33	1.65	1.96
Nuclear	1.20	1.46	1.69
Hydro	1.22	1.43	1.66
Bioenergy	1.52	2.13	2.69
Wind	2.07	3.40	4.62
Geothermal	1.87	3.51	4.77
Solar PV	2.63	4.69	6.49
CSP	3.01	8.05	11.49
Marine	3.91	14.89	21.19

Accumulated generation capacities relative to 2020, in the SDS scenario.

Accumulated generation capacity relative to 2020 (=1)	2030	2040	2050
Coal	1.06	1.07	1.11
Oil	1.06	1.12	1.18
Natural gas	1.22	1.44	1.69
Nuclear	1.25	1.58	1.92
Hydro	1.31	1.60	1.95
Bioenergy	1.81	2.76	3.92
Wind	2.50	4.55	6.95
Geothermal	2.52	5.40	8.24
Solar PV	3.23	6.38	9.84
CSP	3.70	19.88	43.54
Marine	4.72	18.77	30.95

Learning rates typically vary between 5 and 25%. In 2015, Rubin et. al, published "A review of learning rates for electricity supply technologies", which provides a comprehensive and up to date overview of learning rates for a range of relevant technologies [10]:

Technology	Mean learning rate	Range of studies
Coal	8.3%	5.6 to 12%
Natural gas CC	14%	-11 to 34%
Natural gas, gas turbine	15%	10 to 22%
Nuclear	-	Negative to 6%
Wind, onshore	12%	-11 to 32%
Wind, offshore	12%	5 to 19%
Solar PV (modules)	23%	10 to 47%
Biomass power	11%	0 to 24%
Geothermal	-	-
Hydroelectric	1.4%	1.4% (one study)

Learning rates for different technologies (Source: Rubin et al., 2015)

The authors of the review emphasize that "methods, data, and assumptions adopted by researchers to characterize historical learning rates of power plant technologies vary widely, resulting in high variability across studies. Nor are historical trends a guarantee of future behaviour, especially when future conditions may differ significantly from those of the past.".

Still, the study gives an indication of the level of learning rates, which may be expected. 10-15% seems to be a common level for many technologies. PV shows a higher level, whereas nuclear power and coal are in the lower end. The low learning rates of nuclear and coal power may be a result of increasing external requirements, in the shape of higher safety standards for nuclear power and emission norms for coal power, adding to investment costs.

Considering the uncertainties related to the estimation of learning rates a default learning rate of 12.5% is applied for all technologies except solar PV modules, where a learning rate of 20% is deemed to be more probable in view of the high historic rates. It is important to note that this is considering a 25% rate to the PV module and inverter costs, while for the rest of the components and costs for solar PV the 12.5% learning rate is applied. When the abovementioned learning rates are combined with the future deployment of the technologies projected in the IEA scenarios, an estimate of the cost development over time can be deduced.

Technology cost compared to 2020 (2020 = 100%)		STEPS			SDS			Average of STEPS and SDS		
Technology	Learning rate	2030	2040	2050	2030	2040	2050	2030	2040	2050
Coal	12.50%	98%	95%	94%	99%	99%	98%	98%	97%	96%
Oil	12.50%	99%	98%	97%	99%	98%	97%	99%	98%	97%
Natural gas	12.50%	95%	91%	88%	96%	93%	90%	95%	92%	89%
Nuclear	12.50%	96%	93%	90%	96%	92%	88%	96%	92%	89%
Hydro	12.50%	96%	93%	91%	95%	91%	88%	96%	92%	89%
Bioenergy	12.50%	92%	86%	83%	89%	82%	77%	91%	84%	80%
Wind	12.50%	87%	79%	74%	84%	75%	69%	85%	77%	72%
Geothermal	12.50%	89%	79%	74%	84%	72%	67%	86%	75%	70%
Solar PV[5]	20%	73%	61%	55%	69%	55%	48%	71%	58%	51%
CSP	12.50%	81%	67%	62%	78%	56%	48%	79%	62%	55%
Marine	12.50%	77%	59%	56%	74%	57%	52%	76%	58%	54%

Estimated technology cost in the IEA's STEPS and SDS scenarios from 2030 to 2050 [9] *relative to 2020.*

For all thermal technologies, i.e. oil, coal natural gas, nuclear and biomass power, moderate cost decreases are projected, up to around 20% by 2050. The main reason for this is the extensive historic deployment of the thermal technologies, which means that their relative growth is moderate. Solar PV, CSP and marine technologies are expected to see the strongest cost reductions. For solar PV, this is also due to the higher anticipated learning rate (20%) compared to the other technologies (12.5%). In this respect, it should be mentioned that the projection for CSP and particularly marine technologies is associated with particularly high uncertainty, due to the limited application of these power generation technologies today.

Wind is already widely deployed, and hence, the projected cost development is also moderate, a reduction of approximately 28% is projected by 2050. It should be mentioned that almost all the learning curve studies for wind power, referenced by Rubin et al. focus only on the development of the capital cost of the wind turbines ($ per MW). At the same time, focus from manufacturers have been dedicated to increasing the capacity of wind turbines (higher full load hours per MW) and therefore the effective cost reduction expressed as levelized cost of electricity generation, is likely to be higher. This trend is likely to prevail in the future.

Some technologies have several common core components. For example, coal and biomass fired power plants apply a boiler and steam turbine. This implies that learning effects from the deployment of example biomass fired power plants will have a spill-over effect on coal-fired power plants and vice versa.

Global and regional learning
The learning effects found in this review express a global view on technology learning. Considering that the majority of technology providers today are global players this seems to be a reasonable assumption. Therefore, cost reductions generated in one part of the world will easily spread to the other regions.
Still, in a 2020 perspective Indonesian prices of some technologies may be higher (or in some cases lower) than international reference values because local expertise is limited. However, as Indonesian know-how is built up and

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[5] For solar PV, the learning rate is 25% for modules, but the rest of the costs are still considered at 12.5%. Therefore, to accommodate this, the rate here I set to 20%.

technologies are adapted to the Indonesian context within the next decade, it is reasonable to assume that cost will approach the international level.

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