Danish Energy Agency

MOIT

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Viet Nam Technology Catalogue

Technology data input for power system modelling in Viet Nam

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FOREWORD

Today, innovations and technology improvements within renewable energy are taking place at a very rapid pace. Long-term energy planning is very dependent on cost and performance of future energy producing technologies. The objective of this technology catalogue is to provide a solid estimation of costs and performance for a wide range of power producing technologies, thereby building one of the key inputs to good energy planning in Vietnam.

Due to the multi-stakeholder involvement in the data collection process, the technology catalogue contains data that have been scrutinised and discussed by a broad range of relevant stakeholders including the Ministry of Industry and Trade – MOIT, Vietnam Electricity – EVN, independent power producers, local and international consultants, organizations, associations and universities. This is essential because a main objective is to produce a technology catalogue which is well anchored amongst all stakeholders.

The technology catalogue will assist the long-term energy modelling in Vietnam and support government institutions, private energy companies, think tanks and others with a common and broadly recognized set of data for electricity producing technologies in Vietnam in the future.

The Vietnamese Technology Catalogue builds on the approach of The Danish Technology Catalogue, which has been developed by the Danish Energy Agency and Energinet for many years in an open process with stakeholders.

Context
This publication is developed under the Danish Energy Partnership Programme to support the Vietnam Energy Outlook Report 2019 with technology data. Other reports are also developed to support the Vietnam Energy Outlook Report 2019, including the Demand Projection Report and the Fuel Price Projection Report.

Acknowledgements
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Credits
Cover photos by Colourbox

Technology Data for the Vietnamese Power Sector

CONTENT

INTRODUCTION TO METHODOLOGY

The technologies described in this catalogue cover both very mature technologies and emerging technologies which are expected to improve significantly over the coming decades, both with respect to performance and cost. This implies that the cost 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 the section about research and development indicating their technological progress, their future development perspectives and the uncertainty related to the projection of cost and performance data.

The boundary for both cost and performance data are the generation assets plus the infrastructure required to deliver the energy to the main grid. For electricity, this is the nearest 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.

The Vietnamese Technology Catalogue is based on the Indonesian Technology Catalogue from December 2017. Furthermore, Technology Catalogues from China and UK as well as publications from IEA and IRENA have been used as international references.
The text and data have been edited based on Vietnamese cases to represent local conditions. Data tables from the Indonesian Technology Catalogue have been used where no local Vietnamese data was found. For the mid- and long-term future (2030 and 2050) international references have been relied upon for most technologies since Vietnamese data are expected to converge to these international values. In the short run differences may exist, especially for the emerging technologies. Differences in the short run can be caused by e.g. current rules and regulations and level of market maturity of the technology. Differences in both short and long run can be caused by local physical conditions, e.g. seabed material and offshore conditions can affect costs of offshore wind farms and wind speed can affect the dimensioning of rotor vs. generator which can influence the cost.

Land use is assessed but the cost of land is not included in the total cost assessment since this depends on local conditions.

Detailed description of the approach can be found in Appendix 1.

References

1. Danish Energy Agency et al (2017): Technology Data for the Indonesian Power Sector Catalogue for Generation and Storage of Electricity.
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3. IRENA (2018): Renewable Power Generation Costs in 2017, International Renewable Energy Agency, Abu Dhabi.
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1. PULVERIZED COAL FIRED POWER PLANT

Brief technology description
The catalogue distinguishes between three types of coal fired power plants; subcritical, supercritical and ultra-supercritical. The names refer to the input temperature and pressure of the steam when entering the high-pressure turbine. The main differences are the efficiencies of the plants, as shown in the figure below.

Subcritical is defined as 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).

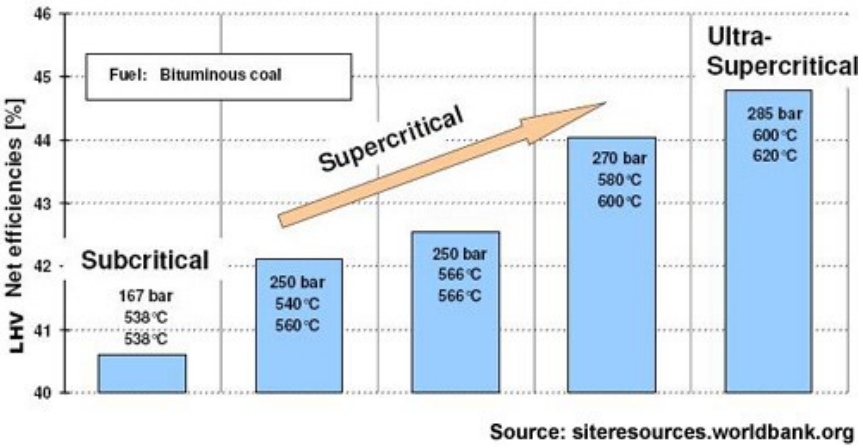

Figure 1: Definitions of sub-, super-, and ultra-supercritical plant (ref. 6).

Input
The process is primarily based on coal but will be applicable to other fuels such as wood pellets and natural gas. Also, heavy fuel oil can be used as start-up or reserve fuel.

Output
Power. 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). In general the self-consumption of the coal-fired plants is about 8% - 10%.

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

Ramping configurations
Pulverized fuel power plants can 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 can 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.

Flexibility in Danish and Chinese coal-based power plants have been analysed in ref. 5 and 6. For German and Danish cases see ref. 8. Typical Danish coal-based power plants have minimum generation of 15-30% and ramping speeds of roughly 4% of nominal load per minute on their primary fuel. These results have been

achieved through retrofitting in relation to existing plants. The investments typically include installation of a boiler water circulation system, adjustment of the firing system, allowing for a reduction in the number of mills in operation, combined with control system upgrades and potentially training of the plant staff.

Table 1: Examples of relevant areas for increased flexibility (ref 6).

<table>
<tr><th>General operational flexibility improvements</th><th>CHP units</th><th>Condensing units</th></tr>
<tr><td rowspan="2">Expand the operational boundaries (i.e. expand the output area)</td><td colspan="2">Lower minimum load</td></tr>
<tr><td colspan="2">Overload ability</td></tr>
<tr><td rowspan="3">Decoupling of heat and electric production and/or when heat is produced and when it is utilised</td><td rowspan="2">Turbine bypass</td><td rowspan="2"></td></tr>
<tr><td>Heat storage</td></tr>
<tr><td>Electric boilers and heat pumps</td><td></td></tr>
<tr><td rowspan="2">More flexible operation mode within output area</td><td colspan="2">Improving ramping speed and fast output regulation</td></tr>
<tr><td colspan="2">Faster/cheaper start/stop of plant</td></tr>
</table>

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 gas turbines.

Disadvantages:

- Coal fired power plants with no pollution control emit high concentrations of NO_x, SO_2 and particle matter (PM), which have high societal costs in terms of health problems and is responsible for thousands of premature deaths each year globally. See ref. 14 for review of health impact.
- Coal has a relative high CO_2 content
- 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, unless the steam temperature (and hence efficiency) is reduced, and biomass fuels may cause corrosion and scaling, if not handled properly.
- Compared to other technologies such as gas turbines or hydro power plants, the coal thermal plants have lower ramp rates, are more complex to operate and require a large number of employees.

Environment

The burning and combustion of coal creates the products CO_2, CO, H_2O, SO_2, NO_2, NO and particle matter (PM). CO, NO_x and SO_2 particles are unhealthy for the brain and lungs, causing headaches and shortness of breath, and in worst case death. CO_2 causes global warming and thereby climate changes (ref. 3).

It is possible to implement filters for NO_x and SO_2.

All coal-fired plants in Vietnam must ensure that the emissions are within the permitted level as specified in:

- National Technical Regulation on Emission of Thermal Power industry (QCVN 22: 2009/BTNMT)

- National Technical Regulation on Ambient Air Quality (QCVN 05:2013/BTNMT)
- National Technical Regulation on Industry Emission of inorganic Substances and dusts (QCVN 19: 2009/BTNMT)

Without applying technical solution to control the emission, the amount of pollutants such as dust, SO_2, NO_x and CO_2 will exceed the allowed limit. Therefore, the coal-fired plants in Vietnam are applying the emission filters to maintain emission within permitted level, including:

- Electrostatic precipitator (ESP): Remove ash from the exhaust
- Flue-gas desulfurization (FGD): Reduction of SO_2, (Some old thermal plants such as Pha Lai 1 and Ninh Binh have not yet applied)
- Selective Catalytic Reduction (SCR): Reduction of NO_x (Thermal plants using Circulating Fluidized Bed boiler do not apply)
- In addition, the chimneys of the plants are required to install a continuous emission monitoring system (CEMS)

Employment
In general, a 1,200 MW coal-fired plant need 2,000-2,500 employees on average during construction and afterwards 600-900 employees continuously for operation and maintenance.

Research and development
Conventional supercritical coal technology is well established and therefore no major improvements of the technology are expected (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 pressure and temperature in the boiler and thus higher efficiencies, though this is unlikely to come at a significantly lower cost (ref. 4).

For increased flexibility see ref. 5, 6 and 8.

Examples of current projects
Subcritical: Quang Ninh coal-fired power plant (ref 9).
Quang Ninh coal-fired power plant is in Ha Long City, Quang Ninh province, with a total capacity of 4x300 MW, developed in 2 phases: Quang Ninh 1 thermal power plant (2x300 MW) operated from March 2011 and 2012 respectively and Quang Ninh 2 (2x300 MW) operated from 2013 and 2014 respectively. Quang Ninh thermal plant is a pulverised coal-fired plant, using subcritical boiler with superheated steam parameters: 174 kg/cm^2 (equal 170 bar) and 541°C. Self-consumption rate of plant is 8.5% (maximum 25.5 MW per unit), the name plate electricity efficiency (net) at LHV is 38%. The annual average efficiency is 35.49%. The main fuel is anthracite from Hon Gai, Cam Pha coal mine and the annual coal consumption is about 3 million tons (for the whole plant of 1200 MW). The auxiliary fuel is fuel oil - No5, used to start the furnace and when the load is less than 77% of the norm. By applying NO_x reduction solution in the combustion chamber, the NO_x emission of Quang Ninh thermal plant is less than 750 mg/Nm^3, the SO_2 and particle matter (PM2.5) content does not exceed 150 and 400 mg/Nm^3 respectively. According to actual measurement, the NO_x, SO_2 and $PM_{2.5}$ emission of Quang Ninh thermal plant is 700 mg/Nm^3, 394 mg/Nm^3, 136 mg/Nm^3 respectively. Quang Ninh thermal plant has a ramp rate of 1% per minute, the warm start-up is 11 hours and cold start-up time is 15 hours.

The capital investment of Quang Ninh thermal plant was 1.41 billion $ (converted to $2016, the administration, consultancy, project management, site preparation cost, the taxes and interest during construction are not included) equal to a nominal investment of 1.17 M$/MW$_e$. The total capital cost (including these components) was 1.55 billion $, corresponding to 1.29 M$/MW$_e$. The fixed O&M cost is 39.97 $/kW$_e$/year and the variable O&M cost is 1.02 $/MWh.

Subcritical Hai Phong coal-fired power plant: (ref 10)
Hai Phong coal-fired plant located in Thuy Nguyen district, Hai Phong city with total capacity of 1,200 MW, include 4 units 300 MW. Hai Phong 1 plant (2x300 MW) started operation from 2009/2010, Hai Phong 2 plant (2x300 MW) started operation from 2013/2014. The plant uses pulverized coal combustion with sub-critical boiler (superheated parameter of 175 kg/cm^3 and 541^{0}C). The self-consumption rate of plant is 8.7% and net electricity efficiency at LHV = 38%. The main fuel of plant is anthracite from Hong Gai – Cam Pha coal mine and the auxiliary fuel used is FO. According to technical design report the $PM_{2.5}$, SO_2 and NO_x emission of plants are as follow: 35.8 mg/Nm^3, 315.1 mg/Nm^3 and 546.5 mg/Nm^3 respectively. The investment was 1.32 billion $

(converted to $2016, the administration, consultancy, project management, site preparation cost, the taxes and interest during construction are not included), equal the nominal investment was 1.1 M$/ MW_e. The total capital (including these components) was 1.53 billion $, corresponding to 1.27 M$/MW. The fixed O&M cost was 45.5 $/ kW_e/year and the variable O&M cost is 1.1 $/MWh.

Super-critical: Vinh Tan 4 coal-fired power plant (ref 11)
General: Vinh Tan 4 coal-fired power plant is in the Vinh Tan Power Center, in the Tuy Phong district, Binh Thuan province. The installed capacity of plant is 1200 MW, including 2 units of 600 MW. It started construction from March 2014, and the first unit was completed in December 2017 and the second one in June 2018.

Vinh Tan 4 thermal plant combusts pulverised coal and was the first Vietnamese coal-fired power plant applying super-critical boiler, with superheated steam parameters: pressure of 25.75 Mpa (~ 258 bar) and temperature of 569°C. The net electricity efficiency of the plant (name plate) is 39.8% (LHV). Vinh Tan 4 thermal plant main fuel is Bitumen imported from Indonesia and Australia. Fuel consumption is approximately 2.8 million tons per year. Diesel oil is used as auxiliary fuel for starting the furnace and burning in low load. Follow the performance test in March 2018, the NO_x emission value is 232 mg per Nm^3, the SO_2 is 138.6 mg per Nm^3 and the $PM_{2.5}$ emission is 8 mg per Nm^3. However, performance test operation is not representative for the emission levels. Operating characteristics of Vinh Tan 4 thermal plant are: ramping 1% per minute, minimum load is 75% of full load (minimum level without burning oil), warm start-up time and cold start-up time are 8.5 hours and 10 hours respectively.

The total investment of Vinh Tan 4 thermal plant was 1.596 billion $ (converted to $2016, the administration, consultancy, project management, site preparation cost, the taxes and interest during construction are not included), corresponding to a nominal investment of 1.33 M$/$MW_e$. The total capital (include these components) was 1.72 billion $, corresponding to 1.43 M$/MW. The fixed O&M cost was 37.97 $/$kW_e$/year and the variable O&M cost was 0.97 $/MWh.

Circulating fluidized bed: Mao Khe thermal plants (ref 12)
General: Mao Khe coal-fired power plant is in the Dong Trieu district, Quang Ninh province, with a total capacity of 440 MW, divided into 2 units of 220 MW. The plant started construction in 2009 and inaugurated in April 2013.

Specifications: Mao Khe thermal plant uses circulating fluidized bed (CFB) combustion and subcritical boiler with superheated steam parameters: 175 kg/cm2 (~172 bar) and 543°C. The self-consumption rate of the plant is 9.4% and the net electrical efficiency is 37.6% (LHV). The main fuel of the plant is anthracite from Mao Khe, Khe Chuoi, Ho Thien, Trang Bach mine. Diesel oil is used as auxiliary fuel for starting the furnace and burning in low load. The SO_2, NO_x and $PM_{2.5}$ emission levels are 472 mg/m^3, 315 mg/m^3 and 118 mg/Nm^3 respectively following investigation data in 2016.

The ramp rate of Mao Khe thermal plant is 0.5%/minute, the minimum load is 85% of full load, the warm start-up time is 10 hours while cold start-up time is 12 hours.

The total investment of Mao Khe thermal plant was 628.2 M$ (converted to $2016, the administration, consultancy, project management, site preparation cost, the taxes and interest during construction are not included), equal the nominal investment was 1.43 M$/$MW_e$. The total capital (include these components) was 736 M$, corresponding to 1.67 M$/MW. The fixed O&M cost was 43.96 $/$kW_e$/year and the variable O&M cost was 1.29 $/MWh.

Data estimate
Below is described the data which the data sheets are based on and how to arrive at the estimates of the parameters in the data sheets.

The estimates of the parameters for sub-critical coal for the short term (2020) relies upon the existing local cases for the most parameters since data from a large number of plants were available. Most of the local plants consist of 2 units of either 300 MW or of 600 MW. In the short-term future, a plant consisting of 2 units of 600 MW each is expected to be the most common. See Table 2.

The difference in minimum generation levels and ramp rate between Vietnamese cases and the Indonesian

Technology Catalogue is significant. Several reports indicate that the lower minimum generation and higher ramp rates can be achieved without additional large investments. But increased operational flexibility is not expected to be realized without new incentives. In the TC current incentives and hence current minimum loads and ramp rates are assumed in 2020 whereas new incentives and more flexible operation abilities corresponding to the Indonesian TC are assumed from 2030. Quality of the coal (caloric value and sulphur content) may affect the O&M costs/start-up cost for plants using domestic coal. Emission values have been converted from mg/Nm^3 to g/GJ based on a conversion factor for coal of 0.35 from Pollution Prevention and Abatement Handbook, 1998.

Table 2: Sub-critical coal fired power plant. 2020 data.

Key parameter	Local cases data average (ref 13)		Indonesian TC (2020)			Vietnamese TC (2020)
		Number of plants	Central	Lower	Upper	
Generating capacity for one unit (MW_e)	450	10	150	100	200	600
Generating capacity for total power plant (MW_e)	1,030	10	150	100	200	1,200
Electricity efficiency, net (%), name plate	37	8	35	30	38	37
Electricity efficiency, net (%), annual average	35	5	34	29	37	35
Ramping (% per minute)	1	7	3.5	2	4	1
Minimum load (% of full load)	67	10	30	25	50	67
Warm start-up time (hours)	5	5	3	1	5	5
Cold start-up time (hours)	10	5	8	5	12	10
Emission $PM_{2.5}$ (mg/Nm^3)	70	3	100	50	150	70
SO_2 (degree of desulphuring, %)	76[1]	3	73	73	95	86
NO_X (g per GJ fuel)	152	3	263	263	263	152
Nominal investment ($M\$_{2016}/MW_e$)[2]	1.12	7	1.43	0.91	1.48	1.12
Fixed O&M ($/$MW_e$/year)	39,500	4	45,300	34,000	56,600	39,500
Variable O&M ($/MWh)	0.69	10	0.13	0.09	0.16	0.69
Start-up costs ($/$MW_e$/start-up)	300	4	110	50	200	300

It was only possible to achieve data from a single Vietnamese super-critical plant which makes the local data less reliable for a central estimate. Hence the Indonesian TC is relied upon for most data. However, like sub-critical plants less flexibility is expected on the operational parameters, ramping, minimum load and start-up time, since similar incentives to operate flexibly are assumed as to sub-critical in the short term. See Table 3.

[1] The average for the SO_2-emissions for the local cases is 244 mg/Nm^3. Using a conversion factor of 0.35 from the Pollution Prevention and Abatement Handbook, 1998 this yields an emission of 85.4 g/GJ. According to appendix 1 the Sulphur content of Vietnamese coal is 350 g/GJ. This gives a degree of desulphuring of 76 %.

[2] Investment costs for the local plants have been normalized to 600 MW with a proportionality factor of 0.8

Table 3: Coal super-critical plant. 2020 data.

Key parameter	Local case: Vinh Tan 4[3]	Indonesian TC (2020)			Vietnamese TC (2020)
		Central	Lower	Upper	
Generating capacity for one unit (MW_e)	600	600	600	600	600
Generating capacity for total power plant (MW_e)	1,200	600	300	800	1,200
Electricity efficiency, net (%), name plate	39.8	38	33	40	38
Electricity efficiency, net (%), annual average	-	37	33	40	37
Ramping (% per minute)	1	4	3	4	1-
Minimum load (% of full load)	75	30	25	50	75
Warm start-up time (hours)	8.5	4	2	5	8
Cold start-up time (hours)	10	12	6	15	10
Emission $PM_{2.5}$ (mg/Nm^3)	8	150	8	150	70
SO_2 (degree of desulphuring, %)	86[4]	73	73	95	86
NO_X (g per GJ fuel)	81	263	263	263	152
Nominal investment ($M\$/MW_e$)	1.33	1.40	1.05	1.75	1.38
Fixed O&M ($\$/MW_e$/year)	37,970	41,200	30,900	51,500	41,200
Variable O&M ($/MWh)	0.97	0.12	0.09	0.15	0.12
Start-up costs ($\$/MW_e$/start-up)	-	50	40	100	50

There are no examples of Vietnamese ultra-supercritical coal-fired power plants, so the data sheets rely solely upon the Indonesian TC for all parameters except investment costs which are described below.

Table 4: Investment costs in international studies, coal-based plants. All numbers are in unit $M\$_{2016}/MW_e$

IEA WEO 2016	**All year: 2015-2040**						
	China			India			
Sub-critical	0.60			1.00			
Super-critical	0.70			1.20			
Ultra-supercritical	0.80			1.40			
IEA Southeast Asia 2015	**Southeast Asia / 2030**						
Super-critical[5]	1.60						
Indonesian TC	**2020**			**2030**	**2050**		
	Central	Lower	Upper		Central	Lower	Upper
Sub-critical (150 MW)[6]	1.25	0.80	1.29	1.21	1.18	0.80	1.29
Super-critical (600 MW)[7]	1.40	1.05	1.75	1.36	1.32	0.99	1.65
Ultra-supercritical	1.52	1.14	1.91	1.48	1.43	1.07	1.79
Vietnamese TC	**2020**			**2030**	**2050**		
	Central	Lower	Upper		Central	Lower	Upper
Sub-critical	1.12	0.60	1.29	1.11	1.09	0.60	1.29
Super-critical	1.38	0.70	1.75	1.39	1.37	0.70	1.65
Ultra-supercritical	1.51	0.80	1.91	1.49	1.48	0.80	1.79

[3] This number comes from performance tests in 2018. Therefore, it is not considered in the central estimate on the Vietnamese Technology Catalogue

[4] The SO_2-emission for the local case is 138.6 mg/Nm^3. Using a conversion factor of 0.35 from the Pollution Prevention and Abatement Handbook, 1998 this yields an emission of 48.5 g/GJ. According to appendix 1 the Sulphur content of Vietnamese coal is 350 g/GJ. This gives a degree of desulphuring of 86 %.

[5] Including interest during construction, engineering

[6] Investment has been normalized to 600 MW with a proportionality factor of 0.8

[7] Investment has been normalized to 2x600 MW with a proportionality factor of 0.8

Table 4 shows estimates of investment costs for the three kinds of coal-fired power plants from various sources and in the bottom the resulting assessment for the Vietnamese TC. Nominal investment has been adjusted to reflect the assumed plant size in Vietnam with a proportionality factor of 0.8 for better comparison with other coal technologies. The method is further described in Annex 1.

There are large variations between the estimates. IEAs estimates for Chinese plants are very low which might be based on high volume production of coal-fired power plants. Furthermore, it is seen that IEA WEO 2016 assumes no reduction in investment costs from 2015 to 2040, while a small reduction is expected in the Indonesian TC.

Investment costs for sub-critical in short term (2020) solely relies upon data from existing local plants as explained above. In 2030 and 2050 an average of the data in the table for sub-critical except the estimates for China is assumed to be the best estimate (avg(1.00; 1.21) for 2030 and avg(1.00; 1.18) for 2050). Estimates for Chinese plants are not assumed realistic in Vietnam and hence are disregarded for the central estimate; however, they are used as lower bounds.

The best estimate for investment costs for super-critical plants are assumed to be the average of the international data in the table except for the Chinese plants. For 2020 the local case is also included in the average (avg(1.2; 1.6; 1.4; 1.33) for 2020, avg(1.2; 1.6; 1.36) for 2030 and avg(1.2; 1.6; 1.32) for 2050).

For ultra-supercritical an average between the available data for the technology are also used incl. the same exception for the estimates for China but with IEA Southeast Asia super-critical estimate also included in the average since ultra-supercritical is expected to have at least as high investment cost as super-critical and including this number increases the estimate (avg(1.4; 1.6; 1.52) for 2020, avg(1.4; 1.6; 1.48) for 2030 and avg(1.4; 1.6; 1.43) for 2050).

References

The description in this chapter is to a great extent a copy of 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 also used:

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Data sheets

The following tables contain the data sheets of the technology. All costs are stated in U.S. dollars ($), price year 2016.

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)	600	600	600	100	650	100	650		1
Generating capacity for total power plant (MWe)	1,200	1,200	1,200	100	1,500	100	1,500		1
Electricity efficiency. net (%). name plate	37	37	37	30	38	33	39		1;2;3
Electricity efficiency. net (%). annual average	35	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)	1	3.5	3.5	1	4	2	4	B	1
Minimum load (% of full load)	67	25	20	25	70	10	30	A	1
Warm start-up time (hours)	5	3	3	1	5	1	5	B	1
Cold start-up time (hours)	10	8	8	5	10	5	12	B	1
Environment									
PM 2,5 (mg per Nm^3)	70	70	70	50	150	20	100	A;E	2;4
SO_2 (degree of desulphuring. %)	86	86	95	73	95	73	95	A	2;4
NO_X (g per GJ fuel)	152	150	38	152	263	38	263	A;C	2;4
Financial data									
Nominal investment (M$/MWe)	1.12	1.21	1.18	0.80	1.29	0.80	1.29	D;G	1;3
- of which equipment (%)									
- of which installation (%)									
Fixed O&M ($/MWe/year)	39,400	38,200	37,000	29,600	49,300	27,800	46,300	F	1;3
Variable O&M ($/MWh)	0.70	0.12	0.12	0.09	0.70	0.09	0.15	F	1;3
Start-up costs ($/MWe/start-up)	300	110	110	50	300	50	200		5

References:

1. Ea Energy Analyses and Danish Energy Agency, 2017, "Technology Data for the Indonesian Power Sector - Catalogue for Generation and Storage of Electricity"
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 currently regulation of coal thermal plant on environment of Viet Nam
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 gradual improvement to international standard in 2050.
B. Assumed no improvement for regulatory capability from 2030 to 2050
C. Calculated from a max of 750 mg/Nm3 to g/GJ (conversion factor 0.35 from Pollution Prevention and Abatement Handbook, 1998)
D. For economy of scale a proportionality factor, a, of 0.8 is suggested.
E. Uncertainty Upper is from regulation. Lower is from current standards in Japan (2020) and South Korea (2050).
F. Uncertainty (Upper/Lower) is estimated as +/- 25%.
G. Investment costs include the engineering, procurement and construction (EPC) cost. See description under Methodology.

Technology	Supercritical 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)	600	600	600	300	800	300	800		1
Generating capacity for total power plant (MWe)	1,200	1,200	1,200	300	1,800	300	1,800		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)	1	4	4	1	4	3	4	B	1
Minimum load (% of full load)	75	25	20	25	75	10	30	A	1
Warm start-up time (hours)	8	4	4	2	8.5	2	5	B	1
Cold start-up time (hours)	10	12	12	6	15	6	12	B	1
Environment									
PM 2,5 (mg per Nm^3)	70	70	70	50	150	20	100	E	2;4
SO_2 (degree of desulphuring. %)	86	86	95	73	95	73	95		2;4
NO_X (g per GJ fuel)	152	150	38	152	263	38	263	C	2;4
Financial data									
Nominal investment (M$/MWe)	1.38	1.39	1.37	0.70	1.75	0.70	1.65	D;F;G	1;3;6;7
- of which equipment (%)									
- of which installation (%)									
Fixed O&M ($/MWe/year)	41,200	40,000	38,700	30,900	51,500	29,000	48,400	F	1;3;6;7
Variable O&M ($/MWh)	0.12	0.12	0.11	0.09	0.97	0.08	0.14	F	1;3
Start-up costs ($/MWe/start-up)	50	50	50	40	100	40	100		5

References:

1 Ea Energy Analyses and Danish Energy Agency, 2017, "Technology Data for the Indonesian Power Sector - Catalogue for Generation and Storage of Electricity"
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 gradual improvement to international standard in 2050.
B. Assumed no improvement for regulatory capability from 2030 to 2050
C. Calculated from a max of 750 mg/Nm3 to g/GJ (conversion factor 0.35 from Pollution Prevention and Abatement Handbook, 1998)
D. For economy of scale a proportionality factor, a, of 0.8 is suggested.
E. Uncertainty Upper is from regulation. Lower is from current standards in Japan (2020) and South Korea (2050).
F. Uncertainty (Upper/Lower) is estimated as +/- 25%.
G. Investment costs include the engineering, procurement and construction (EPC) cost. See description under Methodology.

Technology	Ultra-supercritical 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)	1,000	1,000	1,000	700	1,200	700	1,200		1
Generating capacity for total power plant (MWe)	1,000	1,000	1,000	700	1,200	700	1,200		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)	70	70	70	50	150	20	100	E	2;4
SO_2 (degree of desulphuring. %)	86	86	95	73	95	73	95		2;4
NO_X (g per GJ fuel)	152	150	38	152	263	38	263	C	2;4
Financial data									
Nominal investment (M$/MWe)	1.51	1.49	1.48	0.80	1.91	0.80	1.79	D;F;G	1;3;6;7
- of which equipment (%)									
- of which installation (%)									
Fixed O&M ($/MWe/year)	56,600	54,900	53,200	42,500	70,800	39,900	66,500	F	1;3;6;7
Variable O&M ($/MWh)	0.11	0.11	0.10	0.08	0.14	0.08	0.13	F	1;3
Start-up costs ($/MWe/start-up)	50	50	50	40	100	40	100		5

References:

1. Ea Energy Analyses and Danish Energy Agency, 2017, "Technology Data for the Indonesian Power Sector - Catalogue for Generation and Storage of Electricity"
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 gradual improvement to international standard in 2050.
B. Assumed no improvement for regulatory capability from 2030 to 2050
C. Calculated from a max of 750 mg/Nm3 to g/GJ (conversion factor 0.35 from Pollution Prevention and Abatement Handbook, 1998)
D. For economy of scale a proportionality factor, a, of 0.8 is suggested.
E. Uncertainty Upper is from regulation. Lower is from current standards in Japan (2020) and South Korea (2050).
F. Uncertainty (Upper/Lower) is estimated as +/- 25%.
G. Investment costs include the engineering, procurement and construction (EPC) cost. See description under Methodology.

2. GAS TURBINES

Brief technology description

Simple cycle
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.

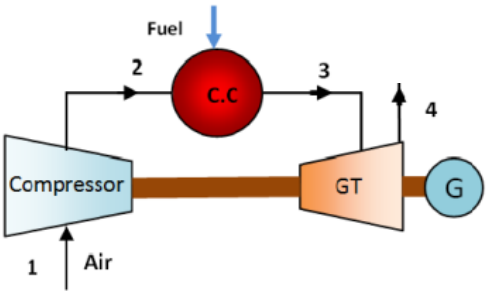

Figure 2: Process diagram of a SCGT (ref. 1)

There are in general two types of gas turbines: 1) Industrial turbines (also called heavy duty) and 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. The following text is about this type of turbines.

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%).

Combined-cycle
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.

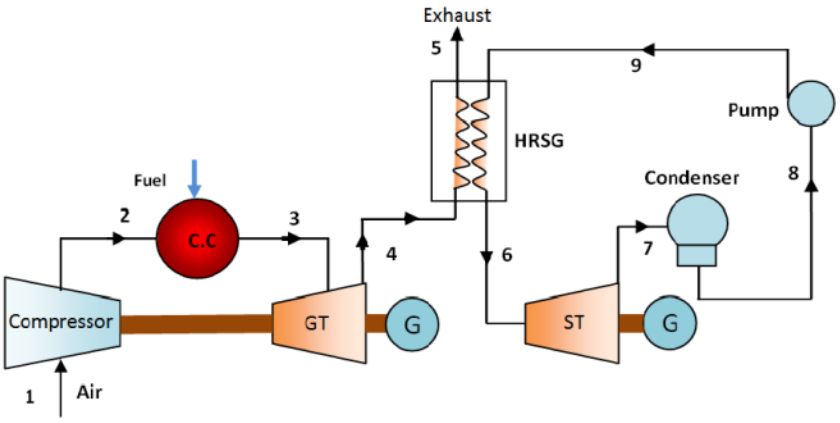

Figure 3: Process diagram of a CCGT (ref. 1)

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 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 (including LNG) 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.

Typical capacities
Simple-cycle gas turbines are available in the 30 kW – 450 MW range. Most CCGT units have an electric power rating of >40 MW.

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 but cheaper in capital costs 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 can operate at part load. This reduces the electrical efficiency and at lower loads the emission of e.g. NO_x and CO will increase, also per Nm^3 of gas consumed. The increase in NO_x emissions with decreasing load places a regulatory limitation on the ramping ability. This can be solved in part by adding de- NO_x units.

CCGT units are to some extent able to operate at part load. This will reduce the electrical efficiency and often increase the NO_x 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
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.
- Large combined-cycle units have the highest electricity production efficiency among fuel-based power production.

- 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.
- Low CO_2 emissions as compared to other fossil-based technologies

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.
- 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.
- 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.
- When CCGT plants use the same gas source, an incident of gas supply can cause loss of several power plants.

Environment

Gas turbines have continuous combustion with non-cooled walls. This means a very complete combustion and low levels of emissions (other than NO_x). Developments focusing on the combustors have led to low NO_x levels. To lower the emission of NO_x further, post-treatment of the exhaust gas can be applied, e.g. with SCR catalyst systems.

Employment

As an example, the 750 MW CCGT Nhon Trach 2 is occupying about 1,000 employees during construction and about 120 employees during operation and maintenance.

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- NO_x combustion technology is assumed. Water or steam injection in the burner section may reduce the NO_x emission, but also the total efficiency and thereby possibly the financial viability. The trend is more towards dry low- NO_x combustion, which increases the specific cost of the gas turbine.

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 NO_x production. To keep a low NO_x emission different options are at hand or are being developed, i.e. dry low- NO_x burners, catalytic burners etc.

Development to achieve shorter time for service is also being done.

Examples of current projects

Nhơn Trach 2 combined cycle gas turbine (CCGT) is in Nhon Trach district, Dong Nai province. The total capacity of the plant is 750 MW, with commercial operation from 2011.

Nhơn Trach 2 thermal plant uses combined cycle gas turbine generation with configuration 2-2-1, including 2 gas turbines, 2 heat recovery steam generators and 1 steam turbine. The electrical net efficiency of the plant is 55%,

the forced outage is expected to be 3% and the planned outage is 4 weeks per year (8%). The main fuel used is natural gas extracted from Cuu Long and Nam Con Son basins. Follow the Environmental Impact report of the first Quarter 2017, the emission of PM2.5 of Nhon Trach 2 CCGT was 30.1 mg/Nm^3, the NO_x emission was 208 mg/Nm^3 and the SO_2 emission was 2.62 mg/Nm^3. The ramping rate of the plant is 5.3% per minute, the minimum load is 40% and the start-up time from warm and cold condition are 4.8 hours and 6 hours respectively.

The total investment was 617 M$ (converted to $2016, the administration, consultancy, project management, site preparation cost, the taxes and interest during construction are not included), corresponding to a nominal investment of 0.82 M$/MW$_e$, The total capital (include these components) was 735 M$, corresponding to 0.98 M$/MW$_e$ The fixed O&M cost was 32.1 $/MW$_e$/year and the variable O&M cost was 0.57 $/MWh.

Data estimate
Below is described the sources which the data sheets are based on and how to arrive at the estimates of the parameters in the data sheets.

Data from six existing CCGT plants in Vietnam were available and the average of the parameters serves as the central estimate for the data sheet in 2020. Except for the unit and plant size where the most common size is chosen. See Table 5. From 2030 and 2050 the Indonesian TC is used except for the financial parameters which are covered separately below.

No data for SCGT plants in Vietnam was available for this study so the Indonesian TC is used in general. For the flexibility parameters (Ramping, Minimum load and Start up time) for CCGT similar parameters as for local CCGT cases are assumed for 2020. Gas turbines can be very flexible but similar to coal fired power plants the gas fired plants are not expected to become more flexible than the current plants without new incentives which are not expected in short term (2020). The financial parameters are covered separately below. Emission values have been converted from mg/Nm^3 to g/GJ based on a conversion factor for coal of 0.27 from Pollution Prevention and Abatement Handbook, 1998.

Table 5: Combined cycle gas turbine, 2020 data from existing local cases, the Indonesian TC and the central estimates for the Vietnamese TC.

Key parameter	Local cases data average		Indonesian TC (2020)			Vietnamese TC (2020)
	(ref 5)	Number of plants	Central	Lower	Upper	
Generating capacity for one unit (MW_e)	650	6	600	200	800	750
Generating capacity for total power plant (MW_e)	650[8]	6				1,500
Electricity efficiency, net (%), name plate	56	5	57	45	62	56
Electricity efficiency, net (%), annual average	52	4	56	39	61	52
Ramping (% per minute)	7	5	20	10	30	7
Minimum load (% of full load)	56	5	45	30	50	56
Warm start-up time (hours)	2	5	2	1	3	2
Cold start-up time (hours)	3	5	4	2	5	3
PM 2.5 (mg per Nm^3)	30.1	1	30	30	30	30
SO_2 (degree of desulphuring, %)	0[9]	1	-	-	-	-
NO_X (g per GJ fuel)	57	1	86	20	86	57
Nominal investment (M\$/MW_e)	0.77	4	0.75	0.65	0.8	0.77
Fixed O&M (\$/MW_e/year)	29,350	4	23,200	17,400	29,000	29,350
Variable O&M (\$/MWh)	0.45	6	0.13	0.1	0.16	0.45
Start-up costs (\$/MW_e/start-up)	70	4	80	60	100	70

In Table 6 are listed international estimations of investment costs for SCGT and CCGT plants. A large variation in investment costs is observed. Very low costs are expected in China. Furthermore, IEA WEO 2016 expects constant investment costs, while a small reduction is expected in the Indonesian TC.

As mentioned above for CCGT the average of the existing local cases is used as the central estimate of investment costs in 2020. For 2020 and 2030 the average of the references in the table is used except that the estimations for China are deemed not realistic in Vietnam. However, they are used as lower bound.

For SCGT a similar approach is applied where the average of the references in the table is used except for the estimations for China for methodology consistency.

[8] One plant typically consists of two gas turbine units and one steam turbine unit.
[9] Sulphur emissions from natural gas fired units are very low because of the low sulphur content in the fuel. Therefore, no desulphuring technology is used for this technology. Data for one local case shows an emission of 2.62 mg/Nm^3

Table 6: Investment costs of gas turbines in international studies. The Danish Technology Catalogue only describes back pressure plants used for CHPs where the heat is used for district heating. Therefore, they are not included here.

IEA WEO 2016	**Capital costs (2016$/W) All year: 2015-2040**						
	China			India			
SCGT	0.35			0.40			
CCGT	0.55			0.70			
IEA Southeast Asia 2015	**Southeast Asia / 2030 (2016$/W)**						
CCGT	0.70						
Indonesian TC[10]	**2020**			**2030**	**2050**		
	Central	Lower	Upper		Central	Lower	Upper
SCGT	0.77	0.65	1.20	0.73	0.68	0.55	0.80
CCGT	0.72	0.62	0.77	0.68	0.63	0.53	0.67
Vietnamese TC	**2020**			**2030**	**2050**		
	Central	Lower	Upper		Central	Lower	Upper
SCGT	0.59	0.35	1.20	0.57	0.54	0.35	0.80
CCGT	0.77	0.55	0.77	0.69	0.68	0.55	0.77

References

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

1. Nag, "Power plant engineering", 2009.
2. Ibrahim & Rahman, "Effect of Compression Ratio on Performance of Combined Cycle Gas Turbine", *Int. J. Energy Engineering*, 2012.
3. Mott MacDonald, "UK Electricity Generation Costs Update", 2010.
4. PECC2, "Nhon Trach 2 combined cycle gas turbine power plant basic design report", 2008
5. Collecting from 6 existing CCGT plants include: Phu My 2.2 (2004), Phu My 4 (2005), Nhon Trach 1 (2008), Nhon Trach 2 (2011), Ca Mau 1 (2008), Ca Mau 2 (2008).

Data sheets

The following pages contain the data sheets of the technology. All costs are stated in U.S. dollars ($), price year 2016.

[10] Investment costs have been adjusted to $\$_{2016}$ and scaled to represent 2*750 MW plants for CCGT and 2*50MW plants for SCGT with a proportionality factor of 0.8. The method is described in Annex A

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
Financial data									
Nominal investment (M$/MWe)	0.59	0.57	0.54	0.35	1.20	0.35	0.80	F;G	1-5
- of which equipment (%)	50	50	50	50	50	50	50		9
- of which installation (%)	50	50	50	50	50	50	50		9
Fixed O&M ($/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".
9. Soares, 2008, "Gas Turbines: A Handbook of Air, Land and Sea Applications".

Notes:

A Assumed gradual 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 costs include the engineering, procurement and construction (EPC) cost. See description under Methodology.

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)	750	750	750	200	800	200	800		1
Generating capacity for total power plant (MWe)	1,500	1,500	1,500	200	1,600	200	1,600		1
Electricity efficiency. net (%). name plate	56	60	61	45	62	55	65		1;3;5;10
Electricity efficiency. net (%). annual average	52	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)	7	20	20	10	30	10	30	C	1;2
Minimum load (% of full load)	56	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)	3	2	2	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)	78	60	20	20	86	20	86	A;D	7;8
Financial data									
Nominal investment (M$/MWe)	0.77	0.69	0.68	0.55	0.77	0.55	0.77	F	1;3;10
- of which equipment (%)	50	50	50	50	50	50	50		9
- of which installation (%)	50	50	50	50	50	50	50		9
Fixed O&M ($/MWe/year)	29,350	28,500	27,600	22,000	36,700	20,700	34,500	B	1;3
Variable O&M ($/MWh)	0.45	0.13	0.12	0.34	0.56	0.09	0.15	B	1
Start-up costs ($/MWe/start-up)	70	70	70	52	87	53	88	B	6

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Notes:

A Assumed gradual 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 costs include the engineering, procurement and construction (EPC) cost. See description under Methodology.

3. HYDROPOWER 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. Typical small capacity.
- 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. Typical large capacity.
- Pumped storage. Provides peak load supply, harnesses water which is cycled between a lower and upper reservoir by pumps which use surplus energy from the system at times of low demand.

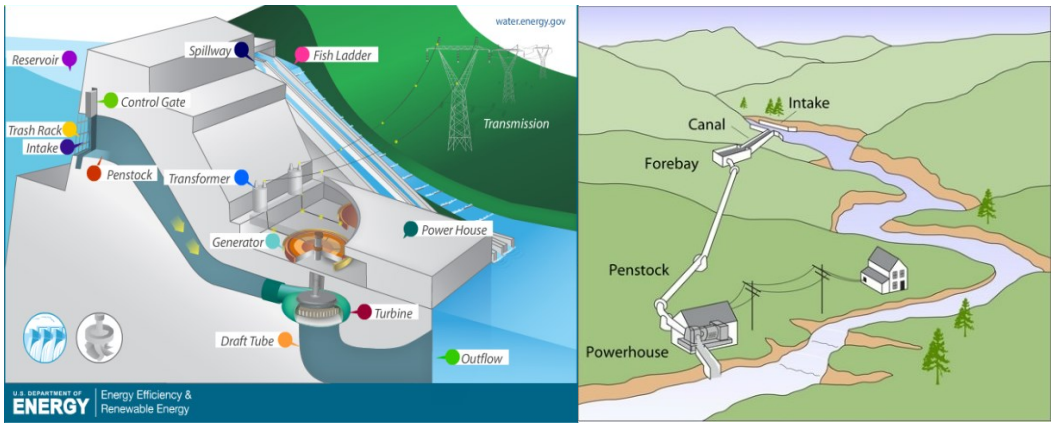

Figure 4: Reservoir and run-of-river hydropower plants (ref. 14)

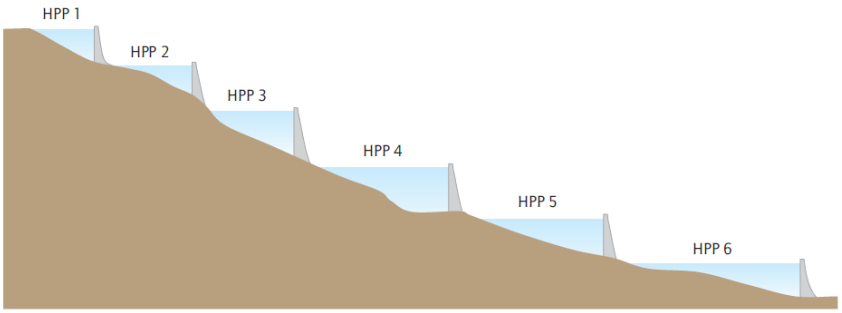

Figure 5: Cascading Systems (ref. 1)

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.

Hydropower systems can range from tens of Watts to hundreds of Megawatts. A classification based on the size of hydropower plants is presented in table below.

Table 7: Classification of hydro*power size*

Type	Capacity
Large hydropower	> 30 MW
Small hydropower	1 MW – 30 MW
Pico and Micro hydropower	< 1 MW

Large hydropower plants often have outputs of hundreds or even thousands of megawatts 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, 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.

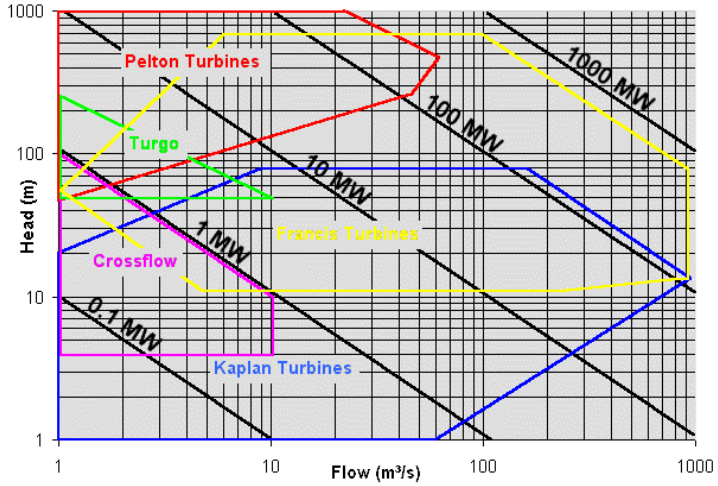

Figure 6: Hydro*power turbine application chart (ref. 2)*

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.

The capacity factor achieved by hydropower projects needs to be looked at somewhat differently than for 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. Data for 142 Clean Development Mechanism (CDM) projects around the world yield capacity factors of between 23% and 95%. The average capacity factor was 50% for these projects.

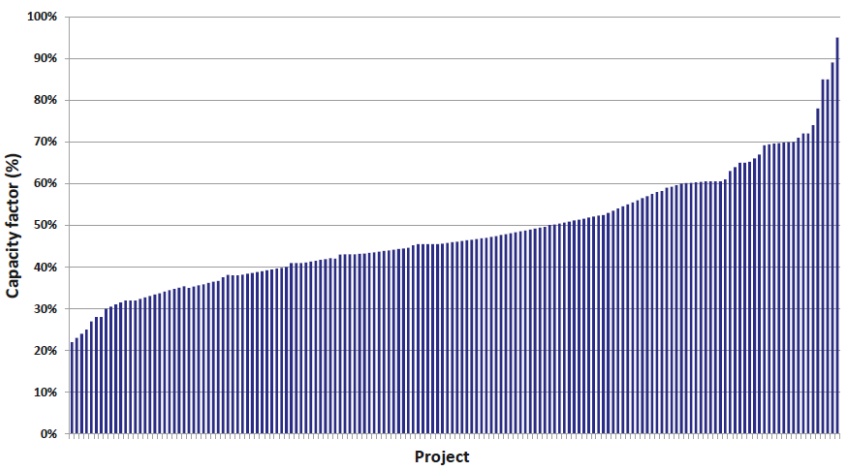

Figure 7: Capacity factors for 142 hydro*power projects around the world (ref. 4)*

Input

The falling water from either reservoir or run-of-river having certain head (height) and flow rate.

Output
Power capacity and energy.

Typical capacities
Hydropower systems can range from tens of Watts to hundreds of Megawatts. Currently up to 900 MW per unit (ref. 15).

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 a clean source, as it doesn't pollute the air.
- Hydropower is a domestic source of energy
- Hydropower is a renewable power source.
- Hydropower with storage is generally available as needed; operators can control the flow of water through the turbines to produce electricity on demand.
- Hydropower facilities have a 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.
- 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 can't 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 and damages mechanical equipment.
- 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.
- Even though hydropower is a flexible renewable energy source there are often limits to the flexibility caused by irrigation needs and other needs.

Environment
Environmental issues identified in the development of hydropower include:
- Safety issues; Hydropower is very safe today. Losses of life caused by dam failure have been very rare in the last 30 years. The population at risk has been significantly reduced through the routing and mitigation of extreme flood events.
- Water use and water quality impacts. The impact of hydropower plants on water quality is very site specific and depends on the type of plant, how it is operated and the water quality before it reaches the plant. Dissolved oxygen (DO) levels are an important aspect of reservoir water quality. Large, deep reservoirs may have reduced DO levels in bottom waters, where watersheds yield moderate to heavy amounts of organic sediments.
- Impacts on migratory species and biodiversity; Older dams with hydropower facilities were often developed without due consideration for migrating fish. Many of these older plants have been refurbished to allow both upstream and downstream migration capability.
- Implementing hydropower projects in areas with low or no anthropogenic activity. In areas with low or no anthropogenic activity the primary goal is to minimize the impacts on the environment. One approach is to

keep the impact restricted to the plant site, with minimum interference over forest domains at dams and reservoir areas, e.g. by avoiding the development of villages or cities after the construction periods.

- Reservoir sedimentation and debris. This may change the overall geomorphology of the river and affect the reservoir, the dam/power plant and the downstream environment. Reservoir storage capacity can be reduced, depending on the volume of sediment carried by the river.
- Lifecycle greenhouse gas emissions. Life-cycle CO_2 emissions from hydropower originate from construction, operation and maintenance, and dismantling. Possible emissions from land-use related net changes in carbon stocks and land management impacts are very small.

Employment

Generally, a new large hydropower plant (110 MW) project will provide around 2,000 – 3,000 local jobs during 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. 18)

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).

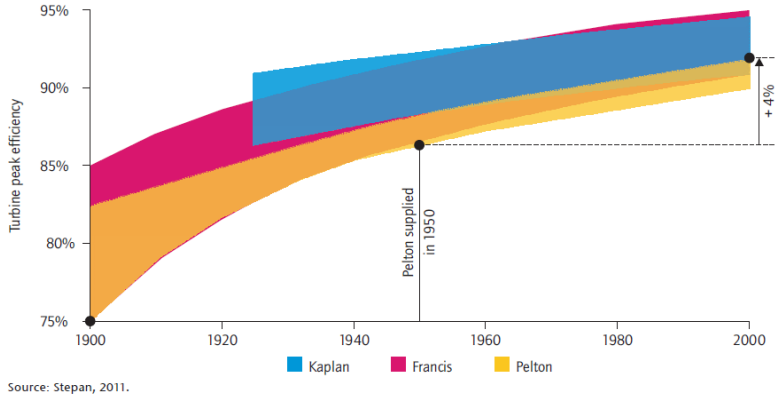

Figure 8: Improvement of hydraulic performance over time (ref. 7)

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

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

- Hydrokinetic turbines: Kinetic flow turbines for use in canals, pipes and rivers. In-stream flow turbines, sometimes referred to as hydrokinetic turbines, rely primarily on the conversion of energy from free-flowing water, rather than from hydraulic head created by dams or control structures. Most of these underwater devices have horizontal axis turbines, with fixed or variable pitch blades.
- 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. 13). 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.

Examples of current projects
Ref. 19 indicate a potential for small hydro (<30 MW) in Vietnam of 7,200 MW. Less than 2,000 MW is installed today.

Large hydropower plant (>30 MW): Lai Chau (ref 20)
Lai Chau is the first upper stream hydropower plant in Vietnam on the Da River hydropower cascade. The plant located in Muong Te district, Lai Chau province, with the installed capacity of 1,200 MW, with 3 units of 400 MW. The construction started in January 2011, and the plant was inaugurated in December 2016, 1 year earlier than the target.

Lai Chau is a reservoir hydropower plant, with catchment area is 26,000 km^2, the reservoir volume is 1.21 billion m^3 and the useful volume is 800 million m^3. The normal rising water level is 295 m and the dead water lever is 270m, the maximum water flow through the turbine is 1664.2 m^3/s. Lai Chau uses Francis turbines with a net electricity efficiency of 96%. The ramping rate is 66.8% per minute and start up time is 2 second.

The total investment of Lai Chau hydropower plant (including the dam) was 1.063 billion $ ($2016, administration, consultancy, project management, site preparation cost, the taxes and interest during construction are not included), equal the nominal investment was 0.89 M$/$MW_e$. The total capital (include these components) was 1.67 billion $, corresponding to 1.39 M$/MW.

Small hydropower plant (<30 MW): Song Bung 6
Song Bung 6 HPP is located in Quang Nam province, has two units with a total capacity of 29 MW and it is a run-of-river type of plant. The construction started in August 2010 and operation started in January 2013. The plant is a low head hydropower using Bulb turbine with the calculating head of 13.4 m (maximum head is 15.5 m) and with a maximum inflow of 240 m^3/s. The volume of the reservoir is 3.29 million m^3 and normal rising water level is 31.8 m. The net electricity efficiency of the plant is 96%. The total investment was 37 M$ ($2016) which is equal to a nominal investment of 1.28 M$/ MW_e.

Expansion existing plant: Hoa Binh HPP expansion (ref 21)
Hoa Binh hydropower plant expansion project includes 2 units with total capacity of 480 MW, the water intake is in Thai Thinh commune, the water tunnel and the expansion plant is in Phuong Lam Ward, Hoa Binh city, Hoa Binh province. According to the Power Master Plan 7 (revised), the project will be put into operation in 2022 – 2023.

The plant includes 2 Francis turbines, three-phase synchronous vertical axis. The expansion plant does not change the existing catchment area and volume of reservoir. The normal rising water level and dead water level is still 117m and 80m respectively, but the min operation water level increases from 80m to 87m. The designed water flow of the expanded plant is 600 m^3/s, increasing the total water flow to 3000 m^3/s.

The total investment of Hoa Binh Expansion was 291.5 million $ ($2016, administration, consultancy, project management, site preparation cost, the taxes and interest during construction are not included), equal the nominal investment was 0.61 M$/ MW_e. The total capital (include these components) was 360 million $, corresponding to 0.75 M$/MW.

Norwegian example
Many current hydroprojects around the world are not new plants but upgrades of existing plants. These projects can involve including new catchment areas (increasing the yearly generation) or increasing the size of the reservoirs and adding turbine capacity. Higher capacity (for the same inflow) can make the plant more suitable for peak load which might be needed to balance wind and solar power. One such modernisation and extension project is the Nedre Rossaga station in Norway, which was completed in 2016. In addition to modernising the existing turbines, a new power station with an additional turbine unit was installed, increasing total installed capacity from 250 MW to 350 MW.

Data estimation
The tables below summarise data for the local cases and the Indonesian TC for 2020.

Table 8: Small hydropower plant

Name	**Song Bung 6**	**Indonesian TC (2020)**		
		Central	Lower	Upper
Capacity [MW]	29	50	10	100
Year of construction	2013	2020	2020	2020
Name plate efficiency [%]	96	95	85	97
CAPEX [M$$_{2016}$/MW]	1.28	2.2	1.4	5.2

The investment costs for the case, Song Bung 6, are very low compared to the Indonesian TC for 2020 and only data for this one case is available. Therefore, the investment costs of the Indonesian TC have also been taken into account when estimating the investment cost for 2020. The investment cost for 2020 is set to 1.75 M$/MW based on an average of the local case (1.28) and the Indonesian TC (2.2).

Table 9: Large hydropower plant

Name	**Lai Chau**	**Indonesian TC (2020)**		
		Central	Lower	Upper
Capacity [MW]	3x400	150	100	2000
Year of construction	2016	2020	2020	2020
Name plate efficiency [%]	96	95	85	97
Ramp rate %/min	66.8	50	30	100
CAPEX [M$$_{2016}$/MW]	0.89	2	0.6	8

Also, the investment costs for the local case, Lai Chau, are very low compared to the Indonesian TC for 2020 and only data for this one case is available. Therefore, the investment costs of the Indonesian TC have also been taken into account when estimating the investment cost for 2020. The investment cost for 2020 is set to 1.5 M$/MW based on an average of the local case (unit 400 MW converted to 150 MW and thus increasing the investment cost to 1.08) and the Indonesian TC (2.0).

Table 10: Investment costs in international studies

IRENA (2018) (M$$_{2016}$/MW)	2017	
All sizes	1.54	
ASEAN (2016) (M$$_{2016}$/MW)	Historical	
Small hydro (23 projects, average capacity: 8.5 MW)	0.85	
TC (2017) (M$$_{2016}$/MW)	2030	2050
Indonesian (small)	2.20	2.20
Indonesian (large)	2.00	2.00

The cost of hydropower is very dependent on the topology of the mountains where it is constructed and the hydro resources. Therefore, it is difficult to estimate a standard value for investment costs that can be used for new hydropower plants. For this catalogue it has been chosen to also use the 2020 value for investment cost for 2030 and 2050. This relies on an average of local cases and the estimates in the Indonesian Technology Catalogue for 2030 and 2050. However, it is highly recommended to take local conditions int account when estimating investment costs for hydro plants in energy planning.

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Data sheets

The following pages contain the data sheets of the technology. All costs are stated in U.S. dollars ($), price year 2016.

Technology	Hydro power plant - Small system								
	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	30	30	30	1	30	1	30		2
Generating capacity for total power plant (MWe)	30	30	30	1	30	1	30		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	0	0	0	0		
SO_2 (degree of desulphuring. %)	-	-	-	-	-	-	-		
NO_X (g per GJ fuel)	0	0	0	0	0	0	0		
Financial data									
Nominal investment (M$/MWe)	1.75	1.75	1.75	0,8	4.0	0,8	4.0	C;D	4;5;6;7
- of which equipment (%)	30	30	30	20	50	20	50		7
- of which installation (%)	70	70	70	50	80	50	80		7
Fixed O&M ($/MWe/year)	41,900	39,800	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)	-	-	-	-	-	-	-		
Technology specific data									
Size of reservoir (MWh)									

References:

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Notes:

A This is the efficiency of the utilization of the waters potential energy. This cannot be compared with a thermal power plant that has to pay for its fuel.
B Uncertainty (Upper/Lower) is estimated as +/- 25%.
C Numbers are very site sensitive. There will be an improvement by learning curve development, but this improvement will equalized because the best locations will be utilized first. The investment largely depends on civil work.
D Investment costs include the engineering, procurement and construction (EPC) cost. See description under Methodology.

Technology	Hydro power plant - large system								
	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	30	2,000	30	2,000		1;8;10
Generating capacity for total power plant (MWe)	150	150	150	30	2,000	30	2,000		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	0	0	0	0		
SO_2 (degree of desulphuring. %)	-	-	-	-	-	-	-		
NO_X (g per GJ fuel)	0	0	0	0	0	0	0		
Financial data									
Nominal investment (M$/MWe)	1.5	1.5	1.5	0.6	8.0	0.6	8.0	D;E	1;4;5;6;9
- of which equipment (%)	30	30	30	20	50	20	50		11
- of which installation (%)	70	70	70	50	80	50	80		11
Fixed O&M ($/MWe/year)	37,700	35,800	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)	-	-	-	-	-	-	-		
Technology specific data									
Size of reservoir (MWh)									

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Notes:

A This is the efficiency of the utilization of the waters potential energy. This cannot be compared with a thermal power plant that has to pay for its fuel.
B Hydro power plants can have a very long lifetime is operated and maintained 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 costs include the engineering, procurement and construction (EPC) cost. See description under Methodology.

4. 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 panels. The photovoltaic (PV) panels are typically 1-2 m^2 in size and have a power density in the range 100-210 W_p/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 panels 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 poly-crystalline silicon wafers. Currently more than 90 pct. of all PV panels 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). Future improvements include development from mono-facial to bifacial panels, which convert light captured on both the front and the back of the cell into power (ref. 4). Another trend is multilayer when area is a scarce resource.
- 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 panels are commercially available. In these panels several layers are deposited on top of each other in order 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).

In addition to PV panels, 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 approximately 40% of the total system costs, inverters around 5-10% (ref 5).

The capacity of a photovoltaic plant can be express in two ways: MW_p is the rated DC capacity (installed panel capacity) of the solar power plants under solar Standard Test Condition (STC) and MW_{ac} is the output capacity deliver to the grid under STC.

PV units can be scaled from kW to MW installations. Economy of scale makes the specific investment costs lower for large plants. In the following text the focus is the utility scale PV (> 1 MW). Rooftop PV will typically have specific investment costs that are 50-100% higher than the larger plants.

Figure 9: Utility scale PV plant

Input
Solar radiation. The irradiation, which the module receives, depends on the solar energy 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 Vietnam varies between approx. 800 kWh and 1700 kWh per m^2. See figure below.

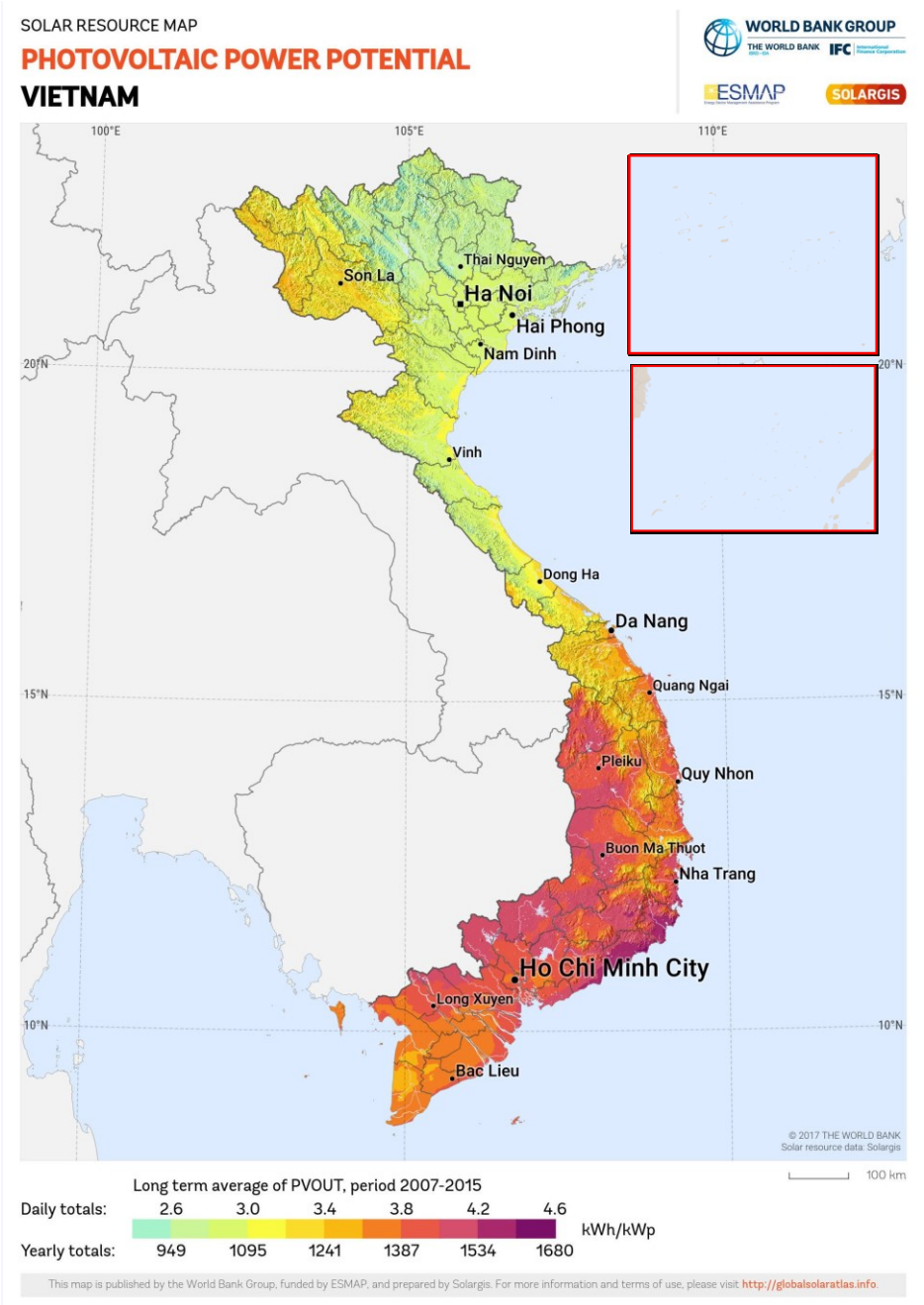

Figure 10: Full load hours (kWh/kW$_p$) for PV in Vietnam. Ref 7.

At locations far from Equator, generation may be increased somewhat by tilting the solar power PV panels towards Equator, in Denmark tilting the panels by 41° yields a benefit of around 22%. In Vietnam, solar power potential is concentrated in the Central Highland, Southern Central and the Southern with latitude from 9° (Soc Trang, Bac Lieu province) to 14° (Quang Ngai, Binh Dinh province), hence the tilt need to be around 11° in average.

The irradiation to the module can be increased even further by mounting it on a sun-tracking device.

Output

All PV panels generate direct current (DC) electricity as an output, which then needs to be converted to alternating current (AC) by use of an inverter; some panels come with an integrated inverter, so called AC panels, 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 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 (kW$_p$). 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/m^2.

In practice, irradiation levels of 1000 W/m^2 are rarely reached, even at locations very close to the Equator. The graph below shows the global irradiance on a fixed plane (W/m^2) during the course of three days in Central Vietnam. Both the daily structure and the variation from day to day can be seen.

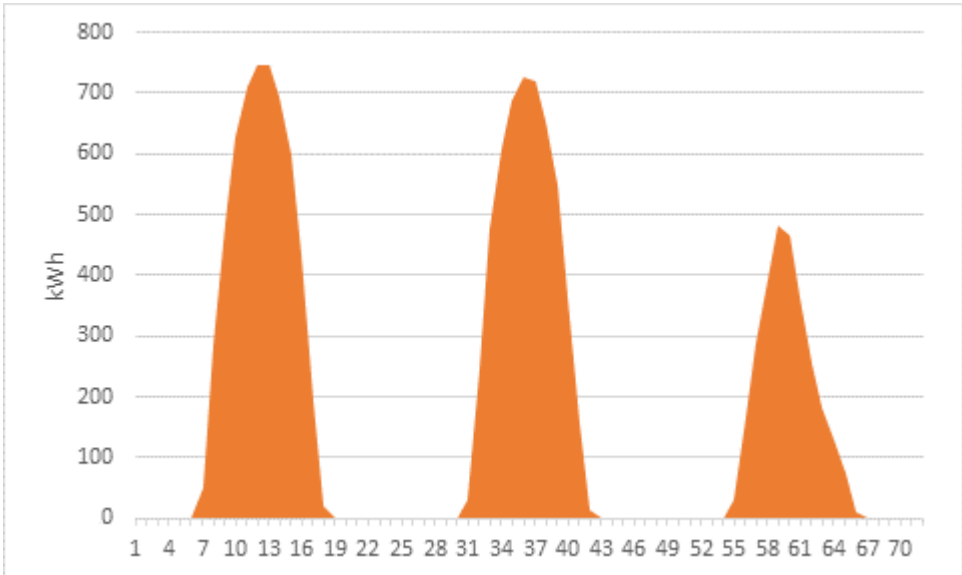

Figure 11: Generation for three days in Central Vietnam. From: www.renewables.ninja

The graph below shows the global irradiance on a fixed plane (W/m^2) during the course of the day in the Ninh Thuan province location; for an average daily profile for September - the month with the best solar conditions.

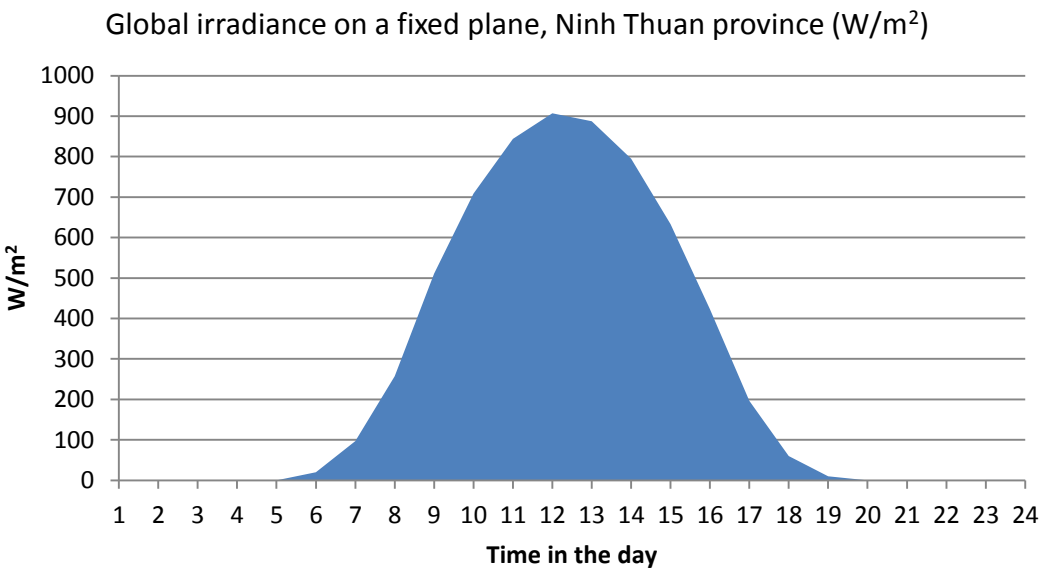

Figure 12: Global irradiance on a fixed plane (W/m^2) during the course of the day in the Ninh Thuan; average daily profile for September, the month with the best solar conditions. Source: Pvsyst Meteo data.

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 from a PV installation with a peak capacity P_p, can be calculated as:
P_p * Global Horizontal Irradiation * Transposition Factor * (1 - Incident Angle Modifier loss) * (1 - PV systems losses and non-STC corrections) * (1 – Inverter losses) * (1 – Transformer losses).

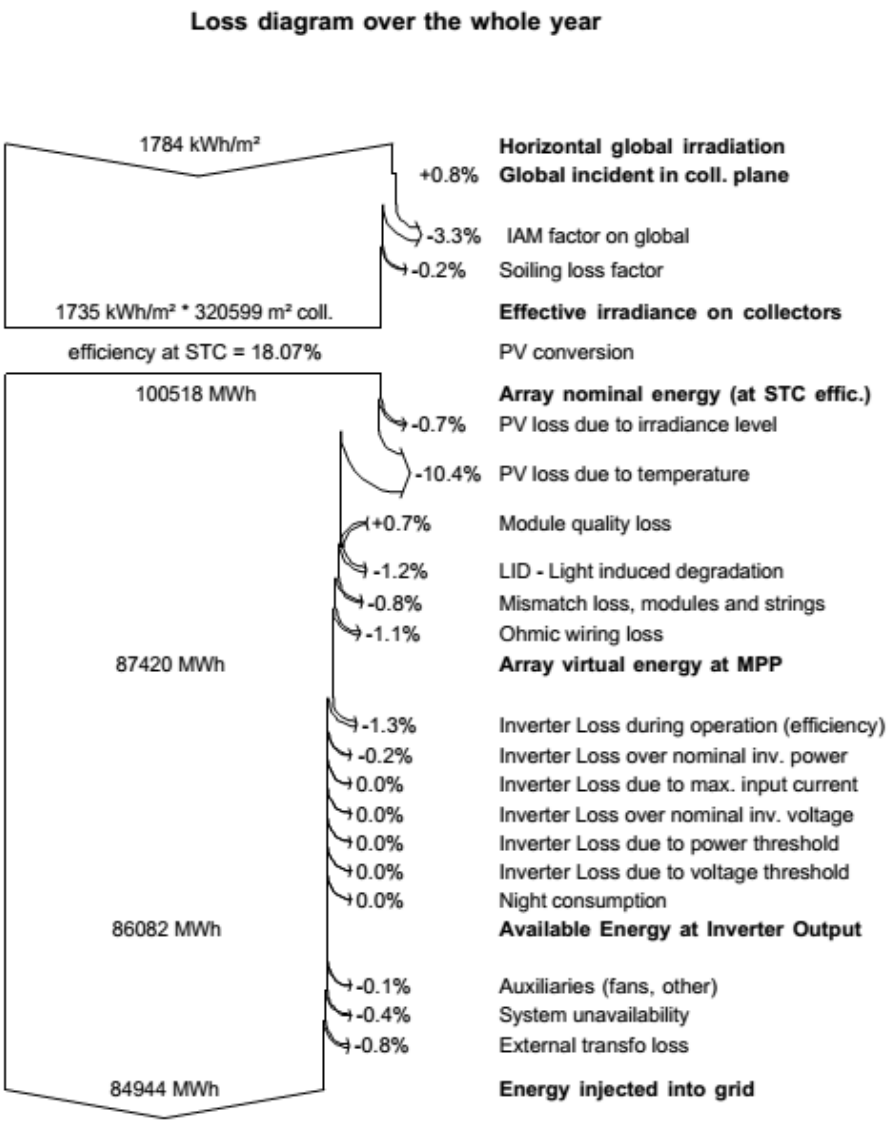

Figure 13: Source: Yearly output calculation result of a 46 MW in Dak Lak province by PVsyst software version V6.67.

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. 11). Failures in the PV system is typical relate to soldering, cell crack or hot spots, yellowing or delamination of the encapsulant foil, junction box failures, loose cables, hail storm and lightning (ref. 12).

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 panels today is 15-17%, with high-end products already above 20%, when measured at standard test conditions. The module area needed to deliver 1 kW_p of peak generation capacity can be calculated as 1 /η_{mod}, and equals 6.25 m^2 by today's standard PV panels.

Typical capacities

Typical capacities for PV systems are available from microwatt to gigawatt sizes. But in this context, it is PV systems from a few kilowatts for household systems to several hundred megawatts for utility scale systems. PV systems are inherently modular with a typical module unit size of 200-350 W_p.

Commercial PV systems are typically installed on residential, office 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 200 MW.

Note that inverter capacity may be selected smaller than the PV panel capacity. The inverter is a expensive element, and the full capacity is only use mid-day. A smaller inverter leads to higher full-load hours.

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 regulation in place, high penetration of PV can also lead to unwanted increases in voltage in distribution grids.

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.
- PV offers grid-stabilization features.
- PV panels have a long lifetime of more than 30 years and PV panels 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 a 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 more 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.
- Forecasting power output of solar power plants is difficult due to the uncertainty of solar irradiation input
- The solar power potential often concentrates in some certain areas and may require increased transmission capacity.
- Solar power is non-inertia so could not support frequency control as traditional power plants.

Environment
The environmental impacts from manufacturing, installing and operating PV systems are limited. Thin film panels may contain small amounts of cadmium and arsenic, but all PV panels 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 PV system is between 1 and 3 years (see a review of studies in ref 16).

The energy payback time is the time required to generate as much energy as is consumed during production and lifetime operation of the system.

Area requirements
The area requirements of solar PV parks vary depending on the specifics of the individual project. The NREL report (ref. 8) features a detailed discussion on challenges related to defining the footprint areas. The *direct area* is the area covered by the installations (solar panels, inverters). The *total area* is the areas of the field. The difference between total area and direct area is the area that still can be used for other purposes, e.g. agriculture.

The report (ref. 13) indicate key numbers for the direct area as 8-12 m^2/kW_p for Indonesia and Thailand. This would also be relevant for Vietnam. With e.g. 1,500 full load hours this would be 5-8 m^2/MWh. IRENA (ref. 12) gives a general key number for solar PV of 10 m^2/MWh.

Circular No.16/2017/TT-BCT dated 12 September 2017 about *Regulation on project development and power purchase contracts applied to the solar power project* stipulates land use requirement for Solar power is less than 12 m^2/kW_p (direct area). The large-scale PV Xuan Thien Thuan Bac uses 11 m^2/kW_p (240 MW_p and 259 ha, *ref 11)*. The large-scale PV Cat Hiep using 12 m^2/ kW_p (49.9 MW_p, 60 ha, *ref 10).*

Employment
The operating of the Cat Hiep (50 MW) in Binh Dinh province is occupying 30 full time employees for the operation and maintenance (*ref 10*). The Xuan Thien Thuan Bac 200 MW in Ninh Thuan province use 100 employees during operation and maintenance (*ref 11)*

Many parts from solar PV can be produced in Vietnam.

Research and development
The PV technology is commercial but is still constantly improved 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.

Assumptions and perspectives for further development
The cost of solar PV projects has decreased significantly. Module prices can be observed at web-sites like http://pvinsights.com/. By mid-July 2017, the average prices of poly silicon solar panels were 0.328 $/Watt, with prices as low as 0.29 $/Watt.

A review by the Danish Energy Agency and Ea Energy Analyses (2017) indicate that the total investment cost of PV plants (panels, inverter and balance of plant) have declined to around 0.80 $ per W_p for utility scale PV plants (MW-size). This price level has been derived from interviews with Danish PV suppliers and a thorough analysis of the recent international tenders for solar PV generation.

IRENA report that total investment costs in 2017 to be between 1 and 3 $/W, with an average of 1.4 $/W. The costs are expected to be reduced with 40% until 2020 (ref. 5). This result in a total cost is in line with the table below.

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

The costs of solar PV panels have declined very significantly; a reduction in the order of 23% has been achieved each time the cumulative production has been doubled.

ASEAN (ref. 14) describes investment costs for PV installations. For units above 1 MW the median investment cost is 2016-US$ 1,963 /MW_p (seven projects from Indonesia, Malaysia, Thailand and one future project from Vietnam).

Examples of current projects

Large scale PV: Bau Ngu lake PV plant (Ref. 11)

Bau Ngu lake PV plant located in Ninh Phuoc and Thuan Nam district, Ninh Thuan province with 61.8 MW_p of installed capacity corresponding to 52 MW_{ac} delivered to the grid. The project started construction in March 2018 and plan to finish in June 2019. Bau Ngu lake PV plant uses fixed tilted plane with tilt angle of 12^0 and azimuth of 180^0. The poly-crystalline silicon PV module will be used with PV panel of 330 W_p and 17% efficiency. There will be 187,200 PV panels used divided into 52 blocks, each block useing an inverter of 1 MW_{ac}. The total land use of Bau Ngu lake PV plant is about 75 ha (where 38.62 ha is on Bau Ngu lake), the nominal land use will be 12 m^2/kW_p. The total investment of project will be 55.75 M$ ($2016, the administration, consultancy, project management, site preparation cost, the taxes and interest during construction are not included), equal the nominal investment of 0.9 $M\$_{2016}/MW_p$ and 1.1 $M\$_{2016}/MW_{ac}$. The total capital (including these components) is 67.2 M$, corresponding to 1.08 $M\$_{2016}/MW_p$.

Large scale PV: Gelex Ninh Thuan PV plant (Ref.12)

The Gelex Ninh Thuan PV solar photovoltaic plant located in Thuan Nam district, Ninh Thuan province with installed capacity of 50 MW_p. The plant started construction in June 2018 and scheduled for operation in June 2019. The fixed tilted plane technology is used with angle of 11^0 and the azimuth is 180^0. The plant uses more than 150,000 multi-crystalline PV panel type 325 W_p, dividing in to 20 blocks, each block use 1 inverter 2,000 kVA to convert DC to AC power. The efficiency of the PV panel at Standard Test Condition is 16.3%. The land area occupied by the project is about 60 ha corresponding to 12,000 m^2/MW_p. The total investment is 43.62 $M\$_{2016}$ ($2016, the administration, consultancy, project management, site preparation cost, the taxes and interest during construction are not included), equal the nominal investment is 0.87 $M\$_{2016}/MW_p$. The total capital (include these components) is 53.84 M$, corresponding to 1.08 $M\$_{2016}/MW_p$.

Rooftop PV: EVN building rooftop PV

The rooftop PV system in EVN building (Ba Dinh district, Ha Noi) have the total capacity of 20 kW_p, it took 45 days from August to September 2017 to deploy. The system consists of 64 PV panels 310 W_p with toal area of 130 m^2. The PV module used is type poly-crystalline silicon (poly c-Si) having efficiency more than 16%. The total investment of system was 22,000 $, corresponding 1.1 $M\$_{2016}/MW_p$.

Data estimation

Table 11 below shows data for two local cases of large-scale PV plants, the Indonesian TC for 2020 and the central estimates in the Vietnamese TC for 2020. For generation capacity, space requirement and DC/AC sizing factor and nominal investment the two local cases are similar and hence the central estimates for 2020 are based on them. For the remaining parameters the Indonesian TC is used except for the investment costs which are handled below. However, for fixed O&M costs the Indonesian TC includes land lease which is not included in this catalogue. Therefore, the Danish TC has been used for the fixed O&M costs.

Table 11: Large scale PV plants. Data for local plants, the Indonesian TC for 2020 and the central estimate for the Vietnamese TC for 2020.

Key parameter	Local cases data average		Indonesian TC (2020)			Vietnamese TC (2020)
	Bau Ngu lake	Gelex Ninh Thuan	Central	Lower	Upper	
Year of construction	2019	2019				
Generating capacity for one unit (MW_e)			0.0002			0.0002
Generating capacity for total power plant (MW_e)	50	40	10	1	50	50
Space requirement (1000 m^2 / MW_e)	12	12	9	7	15	12
Nominal investment ($M\$/MW_e$)	1.1	1.09	0.83	0.70	2.00	1.1
Fixed O&M ($\$/MW_e$/year)	-	-	15,000	11,300	18,800	9,200
Peak capacity (MW_p)	61.8	50	60			62.5
DC/AC sizing factor (W_p/W_{ac})	1.24	1.25	1.1			1.25

Table 12 shows estimates of investment costs from various international references. The expectations in the ASEAN report are high, which is expected to be related to the fact that the 8 projects are among the first in the

respective countries. Lower costs are expected in the Indonesian TC. This is based on 22% learning rate combined with the expected future PV capacity (average between the IEA scenarios 2 DS and 4 DS).

For 2020 the investment costs of the two local PV plants described above is used. For 2030 an average of the estimates from other sources is assumed to be the best central estimate for the Vietnamese TC (an average of the five values of 2030 is used). For 2050 an average is also used but of the three estimates for 2050 and the IEA WEO 2018 estimates for 2040.

Table 12: Investment costs in international studies for large scale PV plants

	2017	2020	2030	2040	2050
IEA WEO 2016. Capital costs (M$$_{2016}$/MW)					
China		1.02	0.84	0.76	
India		1.00	0.80	0.72	
IEA WEO 2018. Capital costs (M$$_{2016}$/MW)					
China	1.12			0.64	
India	1.12			0.62	
IRENA 2018 (M$$_{2016}$/MW)					
General	1.40				
China	1.10				
NREL ATB (M$$_{2016}$/MW)					
			1,15		0.93
TC (2017) (M$$_{2016}$/MW)					
Indonesian (10 MW, DC/AC factor of 1.1)		0.83	0.61		0.45
Danish (4 MW, DC/AC factor of 1.35)		0.94	0.78		0.63
ASEAN (2016) (M$$_{2016}$/MW) – 8 existing projects between 1 and 20 MW. Average is 5.5 MW.					
	1.96				
Vietnamese TC (M$$_{2016}$/MW)					
		1.1	0.84		0.65

References

The description in this chapter is based on the Danish Technology Catalogue (ref. 1).

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 ($), price year 2016.

Technology	Solar PV - Large scale grid connected								
	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWp)	0.0002	0.0002	0.0002					C	5
Generating capacity for total power plant (MWac)	50	50	50	10	200	1	50		1
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	15	35	20	40		1;6
Construction time (years)	1.0	0.5	0.5	0.5	1.5	0.25	1		1;9
Space requirement (1000 m^2/MWac)	14	13	13	8	18	6	18		1
Additional data for non-thermal plants									
Capacity factor (%). theoretical	21.1	21.7	22.8	14	22	16	23		1;2
Capacity factor (%). incl, outages	21.1	21.7	22.8	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	0	0	0	0		
SO_2 (degree of desulphuring. %)	-	-	-	-	-	-	-		
NO_X (g per GJ fuel)	0	0	0	0	0	0	0		
Financial data									
Nominal investment (M$/MWac)	1.10	0.84	0.65	0.70	2.00	0.40	0.80	D;R	1;3;4
- of which equipment (%)	51	50	47						
- of which installation (%)	49	50	53						
Fixed O&M ($/MWac/year)	11,000	8,800	7,400	8,300	13,800	5,600	9,400	Q	5;6
Variable O&M ($/MWh)	0	0	0	0	0	0	0		
Start-up costs ($/MWac/start-up)	0	0	0	0	0	0	0		
Technology specific data									
Global horizontal irradiance (kWh/m2/y)	1,900	1,900	1,900					F	7
DC/AC sizing factor (Wp/Wac)	1.2	1.2	1.2					G	9;10
Transposition Factor for fixed tilt system	1.01	1.01	1.01					H	7
Performance ratio (%)	0.81	0.84	0.87					I	5;6
PV module conversion efficiency (%)	19	23	26						6
Availability (%)	100	100	100						6
Inverter lifetime (years)	15	15	15						6
Output									
Full load hours (kWh/kWac)	1,850	1,900	2,000					J; L	
Peak power full load hours (kWh/kWp)	1,550	1,600	1,650					K; L	

References:

1 Ea Energy Analyses and Danish Energy Agency, 2017, "Technology Data for the Indonesian Power Sector - Catalogue for Generation and Storage of Electricity"
2 Data analysed from www.renewables.ninja for multiple locations in Indonesia.
3 IEA, World Energy Outlook, 2015.
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 Danish Technology Catalogue "Technology Data for Energy Plants, 2012, PV updated in 2015.
7 PVGIS © Europeen Communitees 2001-2012.
8 Learning curve based forecast of technology costs. Ea Energy Analyses, 2017
9 Gelex Ninh Thuan PV solar photovoltaic plant located in Thuan Nam district, Ninh Thuan province with installed capacity of 50 MWp
10 Bau Ngu lake PV plant located in Ninh Phuoc and Thuan Nam district, Ninh Thuan province with 61.8 MWp of installed capacity

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 irradiation is a measure of the energy resource potential available and is depended on the exact geographical location. 1900 kWh/m2 corresponds to a good location at Java.
G The DC/AC shown in the table equals module peak capacity divided by plant capacity. The sizing factor is set to the same value for all years, as it is not the technical factors of the system, which determine the sizing factor. 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 (PR) of a photovoltaic system is the quotient of alternating current (AC) yield and the nominal yield of the generator's direct current (DC). The

PR factor considers losses due to low irradiance, high temperature and losses in cables and inverter. The performance ratio is lower for PV plants in Indonesia compared to Northern European locations because temperature losses are higher in Indonesia. PJB's on-going project on a location at Simeulue Island, Aceh, expects a performance ratio of 80 %.

J The number of full load hours is calculated based on the other values in the table. The calculation formula is: Full load hours = 1046 * sizing factor * 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 assessment of the prices from Danish and Germany tenders for PV capacity in 2016 and the beginning of 2017. The forecasted international price is based on estimated learning rates for the module and investor (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 investor 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 based on the Danish TC.

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

5. WIND POWER

Brief technology description
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.

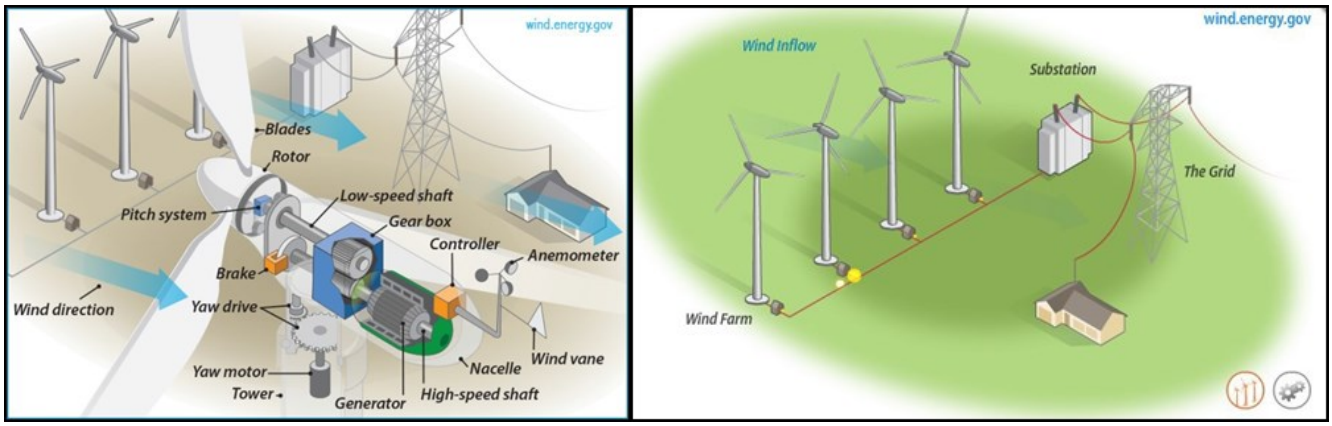


Figure 14: General turbine technology and electrical system

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.

Onshore wind turbines can be installed as single turbines, clusters or in larger wind farms.

Offshore wind farms must withstand the harsh marine environment and installation and maintenance costs are higher (installation at sea, more expensive foundations and cabling, slower processes due to higher risks, dependency on weather). 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.

A nearshore wind farm is a special case of offshore wind which here is defined by a maximum depth of water and distance from shore which leads to lower investment cost compared to offshore wind but higher than onshore wind. Nearshore wind could be considered as intermediate between onshore and offshore. Nearshore wind farms are here defined as located in the water depth of maximum 10 m (foundation from 0 m to 10 m) and the distance from the coast is maximum 12 km. In the Vietnamese context only the near shore type of offshore wind is included and this technology is named offshore wind in the data tables later in this chapter.

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.

The arrangement of the technical requirements within grid codes varies between electricity systems. See ref 16 and 17. However, for simplicity the typical requirements for generators can be grouped as follows:

- Tolerance - the range of conditions on the electricity system for which wind farms must continue to operate;
- Control of reactive power - often this includes requirements to contribute to voltage control on the network;
- Control of active power;
- Protective devices; and
- Power quality.

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. Some manufacturers offer 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 26 m/s for onshore wind turbines (ref. 16).

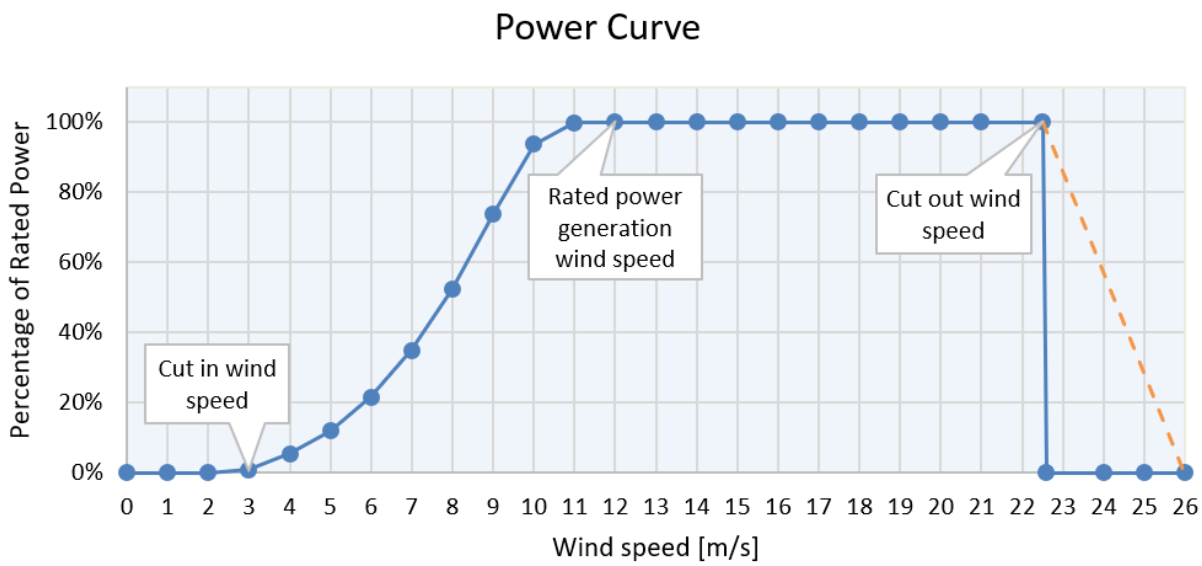


Figure 15: Power curve for a typical wind turbine. Instead of the traditional cut out curve, some turbines have a gradual cut out curve (dashed line).

Generally speaking, the onshore wind resource in Vietnam is scarce. However, a few sites have average wind speeds above 8 m/s.

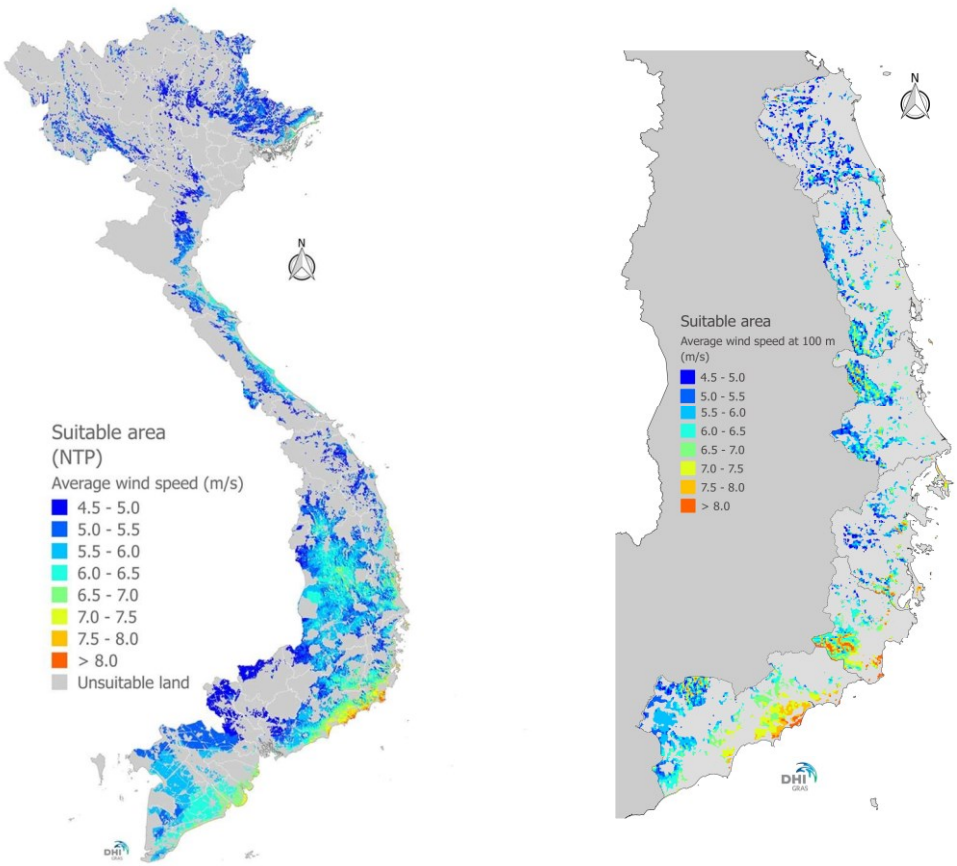
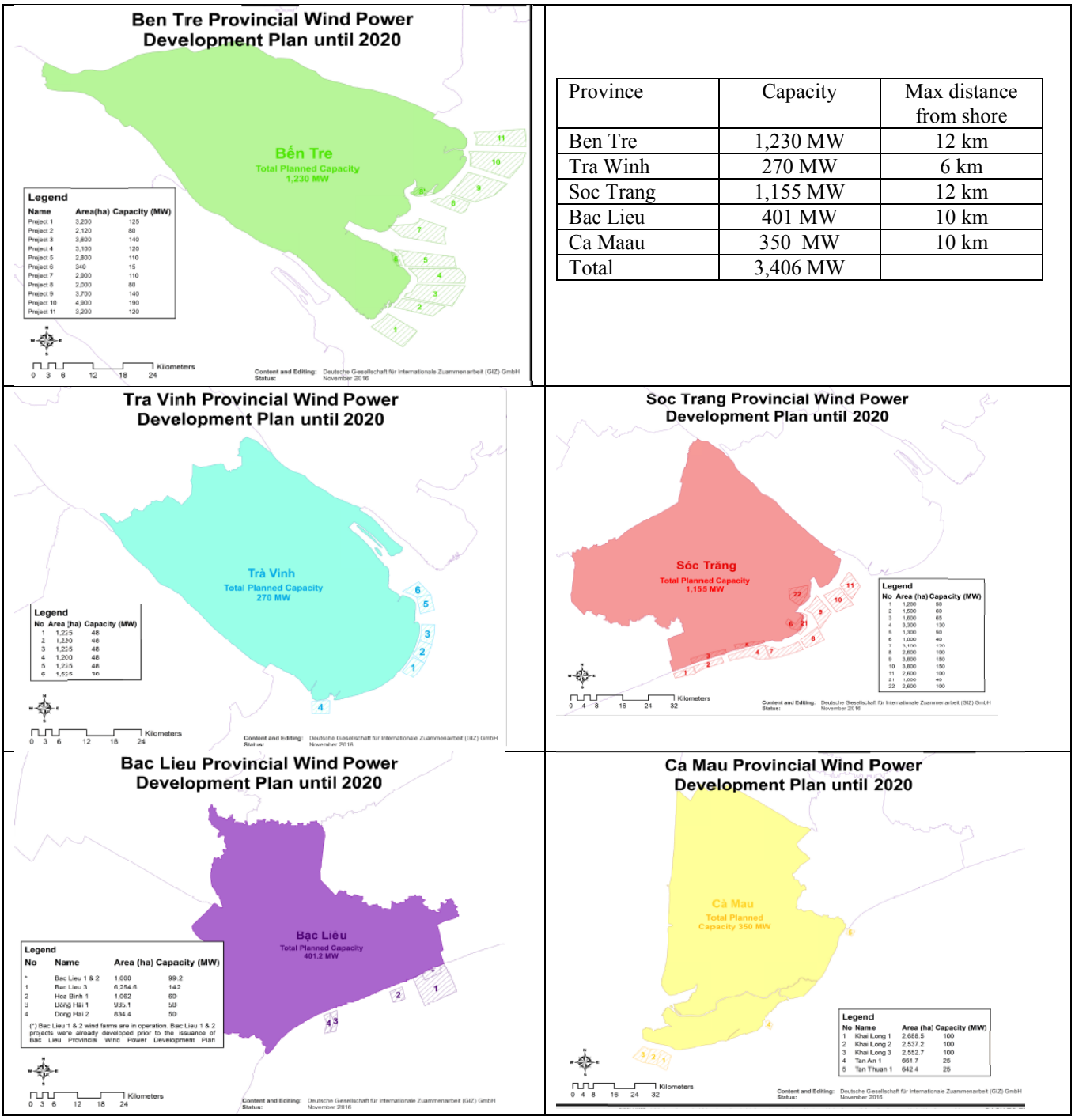


Figure 16: Suitable areas of f National Technical Potential (NTP) overlaid with average wind speed (left) and provincial technical potential (right). Ref. 17.
Only mainland Vietnam showed.

In the figure below a number of potential nearshore sites are listed, with a total capacity of 3,400 MW.



Province	Capacity	Max distance from shore
Ben Tre	1,230 MW	12 km
Tra Winh	270 MW	6 km
Soc Trang	1,155 MW	12 km
Bac Lieu	401 MW	10 km
Ca Maau	350 MW	10 km
Total	3,406 MW	

Figure 17: Examples of potential near shore sites (ref. 23).

In the table below is an indication of the cost impact of different distance to shore and water depth. It is seen that water depth has the highest cost impact (within the studied examples). Similar results are found in (ref 10 with own calculations).

Water depth\ Distance from shore	**4 km**	**8 km**	**10 km**	**12 km**	**15 km**	**20 km**	**25 km**
5m							
10m	0.967	0.974	0.978	0.982	0.988	0.998	1.008
15m	1.000	1.008	1.012	1.016	1.022	1.033	1.043
20m	1.034	1.042	1.046	1.050	1.056	1.067	1.078
25m	1.067	1.075	1.080	1.084	1.090	1.102	1.113
30m	1.124	1.133	1.137	1.141	1.148	1.160	1.172
35m	1.237	1.247	1.252	1.257	1.264	1.277	1.290

Figure 18: Investment costs scaling factor for distance to shore and water depth for Denmark. (ref. 25).

There are however locations, which demonstrate attractive wind speeds. Based on data from the Vietnamese wind resource map the typical capacity factor for a modern onshore turbine located at these good sites will be in the range of 35% corresponding to around 3,055 annual full load hours. The estimate is based on the power curve for a low wind speed turbine (with a large rotor relative to the capacity of the turbine) and the locations are chosen based on conditions at 100 m hub height.

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 in flat terrain are normally dominated by the surface roughness. Also, local obstacles like forest and, for small turbines, buildings and hedges reduce the wind speed like 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.

Wind measurements of at least 1-year duration must be made to predict the generation. Measurements should be at the same height as the nacelle.

Typical capacities
Wind turbines can be categorized according to 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 3-8 MW (ref. 16).

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. Larger generators, larger hub heights and larger rotors have all contributed to increase the electricity generation from wind turbines. Lower specific capacity (increasing the size of the rotor area more than proportionally to the increase in generator rating) improves the capacity factor (energy production per generator capacity), since power output at wind speeds below rated power is directly proportional to the swept area of the rotor. Furthermore, the larger hub heights of larger turbines provide higher wind resources in general.

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 than the current infrastructure can manage. However, there are cases where such infrastructure is built together with the project, e.g. the Lake Turkana project of Vestas in Kenya (ref. 16).

Ramping configurations
Electricity production 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 low wind speeds (less than 4-6 m/s) wind turbines cannot offer ramping regulation, with the possible exception of 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 provide down ramping, 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).

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).

Wind turbine generation can be regulated down quickly, and this feature is regularly used for grid balancing. The

start-up time from no production to full operation depends on the wind resource available.

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

Advantages/disadvantages
Advantages:

- No emissions of local pollution from operation.
- No emission of greenhouse gasses 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 may leave little room for wind farms.
- Variable power production
- Due to the uncertainty of future wind speed forecast of generation can be a challenge.
- Moderate contribution to capacity compared to thermal power plants.
- Visual impact and noise.

Environment
Wind energy is a clean energy source.

The environmental impact from the manufacturing of wind turbines is moderate and is in line with the impact of other normal industrial production. The mining and refinement of rare earth metals used in permanent magnets is an area of concern (ref. 3, 4, 5).

Area requirements
The *direct area* is the area covered by the installations (turbines and access roads). The *total area* is the areas of the field. Wind farms can cover a large area. With a distance between turbines of 6-8 times the rotor diameter, the total area of a wind farm is in the order of 0.2 m^2/W. However, after installation more than 90% of the total area can still be used, e.g. for agricultural purposes. This gives a direct area < 0.02 m^2/W.

In the NREL report (ref. 19) features a detailed discussion on challenges related to defining the footprint areas. Values for specific projects depend on turbine capacity and wind resources.

Circular No. 02/2019/TT-BCT (dated 15 January 2019) about *Regulation on project development and Power purchase contract applied for wind power projects* stipulate the direct area of wind power projects should not excess 0.0035 m^2/W.

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. 14).

The figure below illustrates the distribution of employment in different industries based on wind power in Europe.

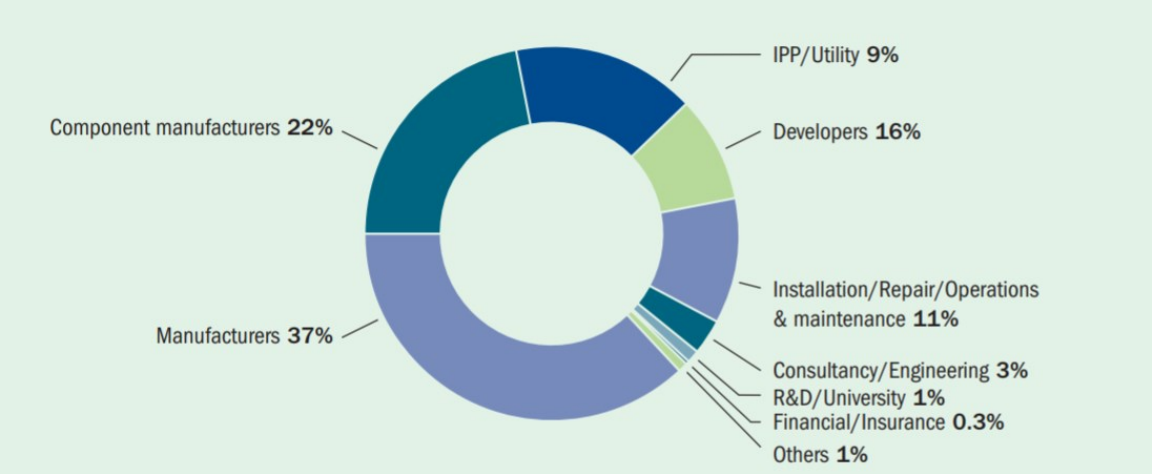


Figure 19: Direct employment by type of company based on wind farm projects in Europe. (ref. 6)

Research and development
The wind power technology is commercial technology but is still constantly improved and decreased in cost (category 3). R&D potential (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

Assumptions and perspectives for further development
The experience with wind power deployment in Vietnam is limited and therefore there is no statistical cost data available that can be relied upon.

Data from onshore projects in Denmark (2013 and 2014 data) show that the average investment costs for these projects are approximately 1.4 M$/MW (ref 10). In Germany, average reported costs for 2012 are higher, approx. 1.8 M$ /MW (ref. 11) and probably more representative for the Vietnamese context because the wind resource in Germany is moderate on many locations and therefore better suited for low-wind speed turbines.

For updated investment costs, specific power and wind speeds, see also the IEA website: community.ieawind.org/task26/dataviewer

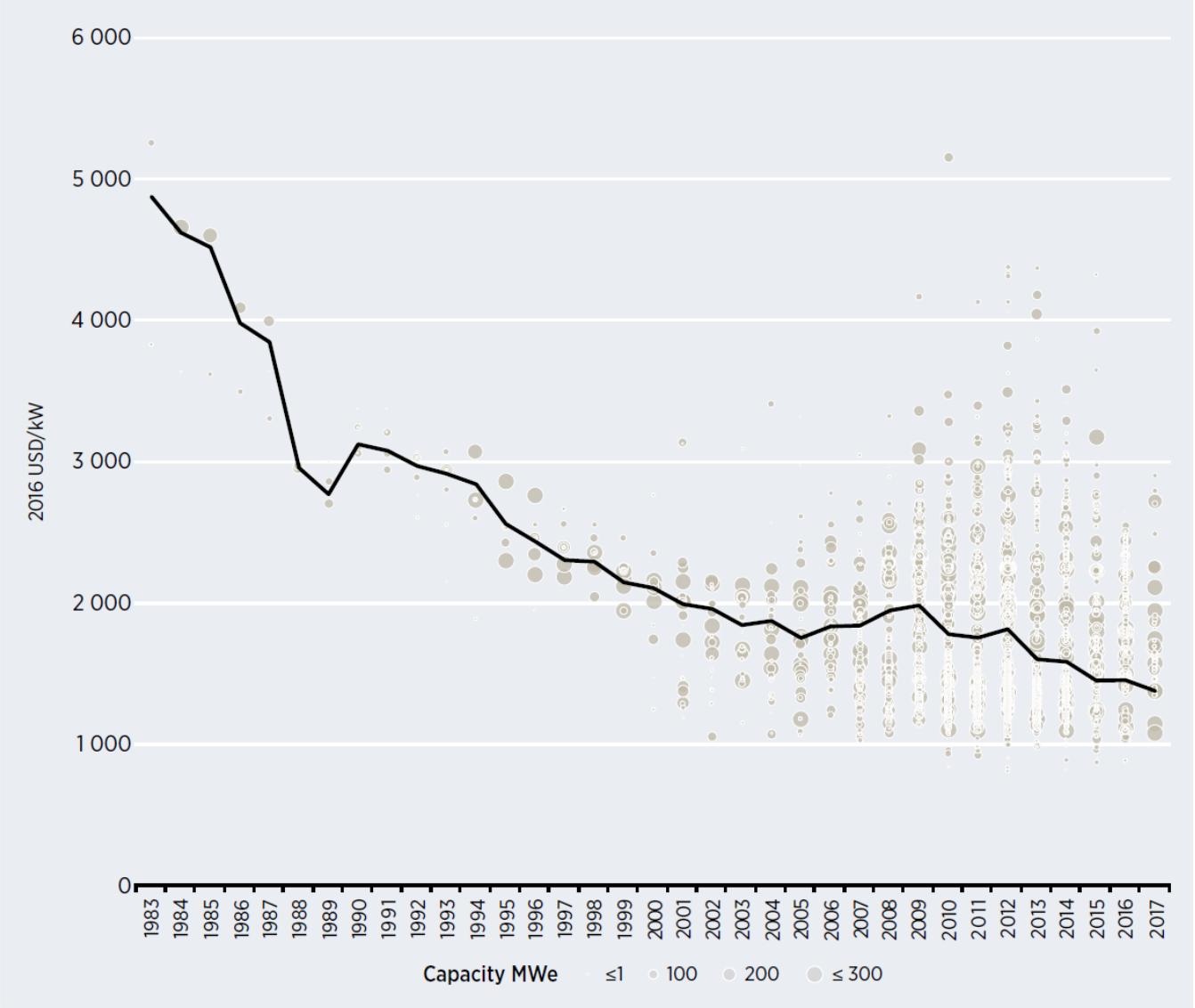
Data from IRENA (ref. 18) indicate total investment costs for onshore wind power of 1.5 M$/MW in 2017 – based on an extensive database.

In the US, average investment cost for onshore wind was just below 2.0 M$/MW in 2012, but since then, costs have decreased to around 1.7 M$/MW by 2015 (ref. 12). Reported costs for India and China have been lower for

the period 2013-2014, 1.3-1.4 M$/MW, according to IRENA, but substantially higher, approx. 2.6 M$/MW (but with very large variation) for "Other Asia" (ref. 13).

In the report Forecasting Wind Energy Costs and Cost Drivers, a non-country specific mean cost for onshore wind of 1.78 M$/MW is provided, representing a mean value for 2014 reported by global wind experts. (ref 15).

Note, that the reported investments above include project development and grid connection.



Source: IRENA Renewable Cost Database.

Figure 20: Total installed costs of onshore wind projects and global weighted average, 1983-2017 (ref.18)

Further technological development and cost reductions by global wind turbine manufacturers can be expected to reduce investment costs further towards 2020. Recent development with results of technology-neutral auctions in Mexico (2017: 20.6 $/MWh, total payment) and Denmark (2018: 3.5 $/MWh premium on top of market price) confirm the development towards a very low cost.

On the other hand, the experience with wind turbines in Vietnam is limited, which is likely to add to costs compared to countries with large-scale deployment. A wind turbine producer assesses that the investment cost in Indonesia would be 1.4-1.5 M$/MW.

Considering the variation in costs across countries/regions reported above, the value of 1.6 M$/MW is considered the best estimate for a planning cost for onshore large-scale wind turbines erected in Vietnam by 2020.

Projection of cost and performance beyond 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 a 1.6% increase in capacity factor by 2030 compared to 2020 and 4.8% improvement by 2050 is assumed.

The predictions of cost reductions are made using the learning rate principle. Learning rates 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. 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 rate of 12.5% this yields a cost reduction of approx. 13% by 2030 and approx. 25% by 2050[11].

Examples of current projects
Onshore wind power plant: Phu Lac wind farm
Phu Lac is an onshore wind farm located in Tuy Phong district, Binh Thuan province. It has a total capacity of 50 MW. The 1st phase of 24 MW started construction in July 2015 and commercial operation started in September 2016.

Phu Lac wind power plant uses wind turbine type 2 MW with the hub height is 95 m with diameter of turbine blades 100 m - the largest type of wind turbine used in Vietnam up to now. The cut-in and cut-out wind speed is 3 m/s and 22 m/s. Following actual operation data, the capacity factor of the plant is 19.6%. The wind farm covers a total area of 400 ha where the permanent direct impact area occupies 9.3 ha (~3,800 m^2/MW) and the temporary direct impact area occupies 8.64 ha (~3,600 m^2/MW) satisfies the regulation under the Circular No. 32/2012/TT-BCT dated 12 November 2012. The project area is mostly barren, uninhabited and has very low agricultural productivity. The investor also plans to develop wind power combined with solar power, high-tech agriculture and tourism.

The total investment was 46.95 $M\$_{2016}$ ($2016, the administration, consultancy, project management, site preparation cost, the taxes and interest during construction are not included), which equals the nominal investment of 1.94 $M\$/MW_p$. Total capital (including these components) is 51.05 M$, corresponding to 2.1 M$/MW.

Near-shore wind farm: Bac Lieu wind farm
Bac Lieu wind farm located in Bac Lieu city, Bac Lieu province with the total installed capacity of 99.2 MW, divided into 2 phases. The first phase of the wind farm is 16 MW and it started construction in September 2010 and was completed in May 2013, the second phase was 83.2 MW, and was inaugurated in January 2016.

Bac Lieu is a nearshore wind farm, including 62 turbines of 1.6 MW each. The turbines are 80 m high (hub high) with more than 200 tons weight each. The turbine blades are 42 m of radius and made of special plastic, with self-folding control system to avoid damage when a storm surges. The capacity factor of the plant is 22.8%. The area of the whole wind farm is about 500 ha.

The total investment of Bac Lieu wind farm was 234 M$, corresponding to 2.36 M$/MW of nominal investment.

For an overview of current international offshore wind projects see [23 and 24].

Data estimation
The table below shows data for the local case, Phu Lac, data from the Indonesian TC and the estimated values for the Vietnamese TC in 2020. The investment cost level of onshore wind in the Vietnamese TC is based on a combination of the

[11] The methodology follows the methodology described in the second appendix of the Indonesian on forecasting cost of electricity production technologies. The learning rate of 12.5 % is based on the research study: TC Edward S. Rubin, Inês M.L. Azevedo, Paulina Jaramillo, Sonia Yeh. Review article. A review of learning rates for electricity supply technologies. Elsevier 2015

costs of the local case in Phu Lac and the Indonesian TC for 2020. Because only one local case is available it has been chosen to rely more on the data from the Indonesian TC for 2020. Regarding O&M costs the values in the Indonesian TC are very high compared to other sources, e.g. the Danish TC from 2018. Therefore, it has been chosen to rely more on the estimates from the Danish TC. However, 50 % has been added to the costs to represent higher costs in the less mature Vietnamese market (corresponding to the difference in Danish and Vietnamese investment costs).

Table 13: Onshore wind power plant data from local plant, Indonesian TC for 2020 and central estimate for 2020 in the Vietnamese TC.

Key parameter	**Local case**	**Indonesian TC (2020)**			**Vietnamese TC (2020)**
	Phu Lac	**Central**	**Lower**	**Upper**	
Year of construction	2016				
Generating capacity for one unit (MW_e)	2	3.5			3
Generating capacity for total power plant (MW_e)	24	70			30
Construction time (months)	14	18			18
Space requirement (1000 m^2 / MW_e)	7.4	14			14
Nominal investment (M$/$MW_e$)	1.94	1.5	1.4	2.0	1.60
Fixed O&M ($/$MW_e$/year)	-	60,000	30,000	70,000	40,500
Variable O&M ($/MWh)	-	0	0	0	4.2
Rotor diameter (m)	100				100
Hub height (m)	95				95
		Danish TC (2020)			
Fixed O&M ($/$MW_e$/year)	-	27,000	24,300	29,700	
Variable O&M ($/MWh)	-	2.8	2.5	3.1	

Table 14: Near-shore wind power plant data for local plant and Danish TC for 2020

Name	**Bac Lieu (Near shore)**	**Danish TC – Near shore (2020)**		
		Central	Lower	Upper
Capacity unit	1.6	10	4	10
Capacity plant	99.2	-		
Year of construction	2013 (phase 1) 2016 (phase 2)			
Construction time (month)	30 (phase 1)	24	12	36
Hub height	80	115	-	-
Rotor diameter	84	190	-	-
Total area (1000 m^2/MW)	50.4	185	168	204
CAPEX [M$2016/MW] including grid connection	2.36	2.26	2.03	2.39

Table 15: Investment costs in international studies (On shore and off shore). For off shore wind the costs for grid connection are included[12].

Onshore			
IEA WEO 2016. Capital costs (2016$ per W)	**2020**	**2030**	**2040**
China	1.20	1.20	1.20
India	1.32	1.30	1.28
IEA WEO 2018. Capital costs (2015$ per W)	**2017**		**2040**
China	1.20	-	1.18
India	1.08	-	1.04
IRENA 2018 (2016$/W)	**2016**		
General	1.35		

[12] The IEA WEO is not clear on this, but the grid costs are expected to be included.

China	1.20		
India	1.10		
TC (2016$ per W)	**2020**	**2030**	**2050**
Indonesian (2017)	1.50	1.31	1.11
Danish (2018) (updated from August 2016)	1.12	1.03	0.94
Vietnamese TC	1.60	1.31	1.11
Off shore (2016$ per W)			
IEA WEO 2016	2020	2030	2040
China	3.7	3.1	2.8
India	3.9	3.2	2.95
IEA WEO 2018	2020	2030	2040
China	4.1	-	2.7
India	3.3	-	2.2
	2020	2030	2050
Indonesian TC (2017)	3.50	3.05	2.59
Danish TC – near shore (2018)	2.26	1.98	1.69
Danish TC – off shore (2018)	2.60	2.25	1.93
Vietnamese TC	2.36	2.25	1.93

For onshore wind in China, India, Indonesia the data estimates are in agreement. The Indonesian estimate for 2020 is relatively high – because the wind industry in the country is on an early stage. The Danish estimates are lower. For Vietnam onshore wind the local cases have been used for 2020 (however, larger capacity) and international (Indonesian) values for 2030 and 2050.

Also, for off shore wind, the local case has been used for 2020 and then Danish off shore values for the following years. The cost level is expected to be higher in Vietnam than in the very mature North European market. Therefore, the cost estimates for offshore wind, not near shore, has been used here for the Vietnamese offshore projects although they are expected to be closer to shore. For Vietnam the off shore described in this Technology Catalogue is expected to be on water depths less than 10 m and up to 12 km from the shore.

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Data sheets

The following pages contain the data sheets of the technology. All costs are stated in U.S. dollars ($), price year 2016.

Technology	Wind power - Onshore								
	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	3.0	4.0	5.0						3
Generating capacity for total power plant (MWe)	30	80	100						1
Electricity efficiency. net (%). name plate								A	
Electricity efficiency. net (%). annual average									
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	-	-	-	-	-	-	-		
Capacity factor (%). incl, outages	-	-	-	-	-	-	-		
Ramping configurations									
Ramping (% per minute)	-	-	-	-	-	-	-	D	
Minimum load (% of full load)	-	-	-	-	-	-	-	D	
Warm start-up time (hours)	-	-	-	-	-	-	-		
Cold start-up time (hours)	-	-	-	-	-	-	-		
Environment									
PM 2,5 (gram per Nm^3)	0	0	0	0	0	0	0		
SO_2 (degree of desulphuring. %)	-	-	-	-	-	-	-		
NO_X (g per GJ fuel)	0	0	0	0	0	0	0		
Financial data									
Nominal investment (M$/MWe)	1.60	1.31	1.11	1.4	2.0	1.0	1.5	C	1
- of which equipment (%)	65	65	65					B	2; 3
- of which installation (%)	35	35	35					B	2; 3
Fixed O&M ($/MWe/year)	40,500	37,800	35,900	36,500	44,600	28,700	43,100	E	4
Variable O&M ($/MWh)	4.2	3.9	3.6	3.8	4.7	2.8	4.3	E	4
Start-up costs ($/MWe/start-up)	0	0	0						
Technology specific data									
Rotor diameter (m)	120	130	150	90	130	100	150		3
Hub height (m)	90	100	110	85	120	85	150		3
Specific power (W/m2)	309	301	283	270	350	250	350		3
Avability (%)	97	98	98	95	99	95	99		3

References:

1 Ea Energy Analyses and Danish Energy Agency, 2017, "Technology Data for the Indonesian Power Sector - Catalogue for Generation and Storage of Electricity"
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 Generation and Conversion
4 Danish Energy Agency, 2018.Technology Data on Energy Plants - Generation of Electricity and District Heating, Energy Storage and Energy Carrier Generation and Conversion
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 Equipment: Cost of turbines including transportation. Installation: Electrical infrastructure of turbine, civil works, grid connection, planning and management. The split of cost may vary considerably from project to project.
C 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.
D 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).
E The O&M costs have been set at 50 % higher than in the Danish TC (ref. 4 above).

Technology	Wind power - Offshore								
	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	3.5	10.0	12.0	1.6	8.0	4.0	20.0		1
Generating capacity for total power plant (MWe)	105	300	360	48	240	120	600		1
Electricity efficiency. net (%). name plate								A	
Electricity efficiency. net (%). annual average								A	
Forced outage (%)	4.0	3.0	3.0	1.0	5.0	1.0	5.0		1
Planned outage (%)	0.3	0.3	0.3	0.1	0.5	0.1	0.5		1
Technical lifetime (years)	27	30	30	20	35	20	35		1
Construction time (years)	3.0	2.5	2.5	1.5	4	1.5	4		1
Space requirement (1000 m^2/MWe)	185	185	185	168	204	168	204		1
Additional data for non-thermal plants									
Capacity factor (%). theoretical	-	-	-	-	-	-	-		
Capacity factor (%). incl, outages	-	-	-	-	-	-	-		
Ramping configurations									
Ramping (% per minute)	-	-	-	-	-	-	-	B	
Minimum load (% of full load)	-	-	-	-	-	-	-	B	
Warm start-up time (hours)	-	-	-	-	-	-	-		
Cold start-up time (hours)	-	-	-	-	-	-	-		
Environment									
PM 2,5 (gram per Nm^3)	0	0	0	0	0	0	0		
SO_2 (degree of desulphuring. %)	-	-	-	-	-	-	-		
NO_X (g per GJ fuel)	0	0	0	0	0	0	0		
Financial data									
Nominal investment (M$/MWe) including grid investment	2.36	2.25	1.93	1.95	2.75	1.56	2.15	C	1
- of which equipment (%)	45	45	45	40	50	40	50	A	1
- of which installation (%)	55	55	55	50	60	50	60	A	1
Fixed O&M ($/MWe/year)	50,000	43,000	36,000	45,000	53,000	29,000	40,000		1; 2
Variable O&M ($/MWh)	3.7	3.1	2.5	3.4	3.8	1.9	2.7		1; 2
Start-up costs ($/MWe/start-up)	0	0	0						
Technology specific data									
Rotor diameter (m)	120	210	240						1
Hub height (m)	90	125	140						1
Specific power (W(m2)	309	353	332						1
Availability (%)	97	97	98	95	99	95	99		1

References:

1 Danish Energy Agency, 2018.Technology Data on Energy Plants - Generation of Electricity and District Heating, Energy Storage and Energy Carrier Generation and Conversion

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

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

C The costs for offshore (not near shore) from the Danish TC (ref. 1 above) has been used as a best estimate for offshore in Vietnam.

6. BIOMASS POWER PLANT

Brief technology description
Biomass can be used to produce electricity or fuels for transport, heating and cooking. The figure below shows the various products from biomass. This chapter focuses on solid biomass for combustion to power generation.

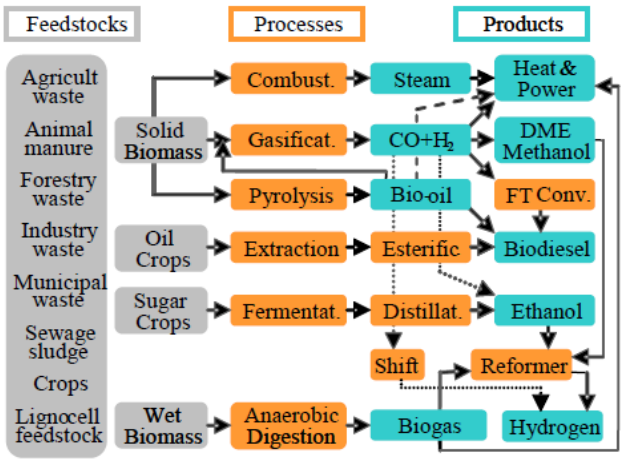

Figure 21: Biomass conversion paths (ref. 1)

The technology used to produce electricity in biomass power plants depends on the biomass resources. Due to the lesser heating value of biomass compared to coal and the limitations in steam temperature and pressure due the mineral contents of the ash, 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).

Vietnam has abundant biomass resources. The sources include palm oil, sugar cane, rubber, coconut, paddy, corn, cassava, cattle, and municipal waste. Municipal waste is treated in a separate chapter of this technology catalogue.

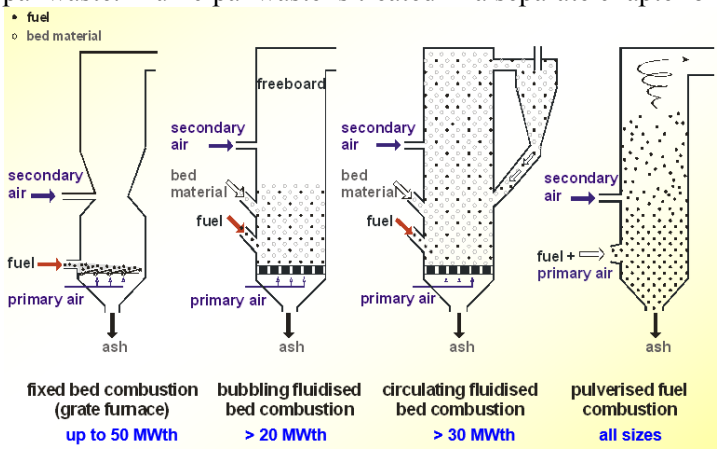

Figure 22: Technologies for industrial biomass combustion (ref. 4)

Table 16: 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 feedstocks range from 5 – 18 GJ/ton, with the palm oil empty fruit brunches (EFB) as the lowest and coconut shells as the highest. The calorific value is highly dependent on the moisture content of the fuel.

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, especially in those co-firing plants that are seasonally supplied with large quantities of biomass (ref. 5).

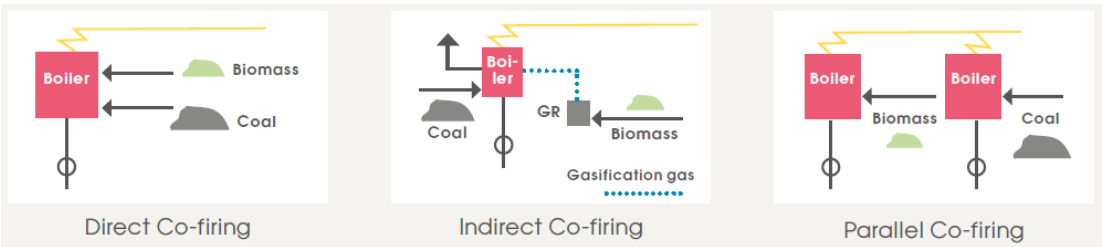

Figure 23: Different biomass co-firing configurations (ref. 6)

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.

Input

Biomass; e.g. residues from industries (wood waste, empty fruit bunches, 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 NO_x and particulates, increased ash, corrosion and slag deposits. Flue gas cleaning systems as ammonia injection (SNCR), lime injection, back filters, De NO_x 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.

Typical capacities
Large: bigger than 50 MW_e
Medium: 10 – 50 MW_e.
Small: 1 – 10 MW_e.

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.
- Burning biomass is considered CO_2 neutral.
- Using biomass waste will usually be cheap.

Disadvantages:

- The availability of biomass feedstock is locally dependent.
- Use of biomass can have negative indirect consequences e.g. in competition with food production, nature/biodiversity.
- 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 (ref. 10).

Research and development
Biomass power plants are a mature technology with limited development potential (category 4). However, in Vietnam, using biomass for power generation is relatively new.

A significant share of biomass energy is consumed in Vietnam for traditional uses, for example cooking with 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 Vietnam now. Solid and liquid palm oil wastes seem to be the most favourable choices for biomass feedstock due to the easy access and handling and also the availability.

Direct, traditional uses of biomass for heating and cooking applications rely on a wide range of feedstock and simple devices, but the energy efficiency of these applications is very low because of biomass moisture content, low energy density, inefficient combustion and the heterogeneity of the basic input. A range of pre-treatment and upgrading technologies have been developed to improve biomass characteristics and make handling, transport, and conversion processes more efficient and cost effective. Most common forms of pre-treatment include: drying, pelletization and briquetting, torrefaction and pyrolysis, where the first two are by far the most commonly used.

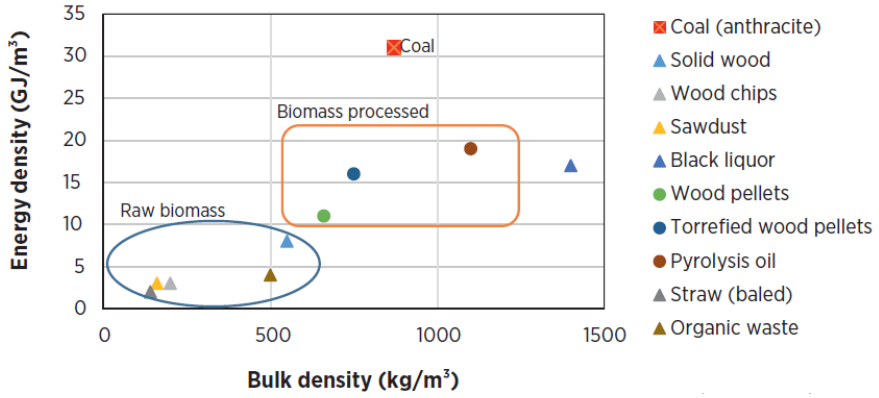

Figure 24: Energy density of biomass and coal (ref. 11)

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.

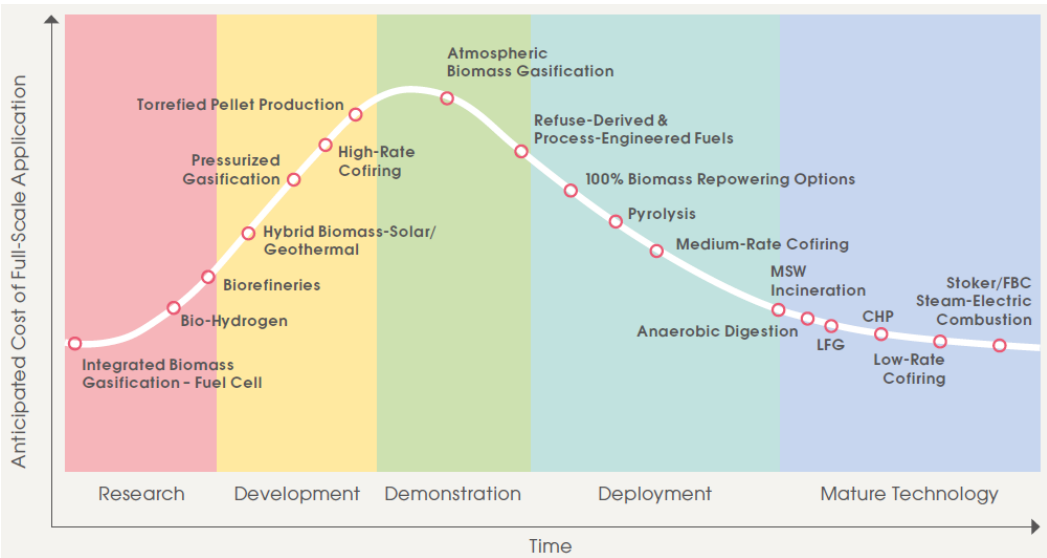

Figure 25: Biomass power generation technology maturity status (ref. 12)

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.

Table 17: 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	30%	35%	35%

	long residence time			
Gasification	High temperature, long residence time	5%	10%	85%

ASEAN has analysed investment costs for biomass (Ref. 15) in Indonesia, Malaysia and Thailand. While several smaller units had investment costs of US$$_{2016}$ 2.5/W, a 15 MW Indonesian unit have much lower costs of US$$_{2014}$ 0.6/W.

Examples of current projects

The KCP Phu Yen Biomass Power Plant is located in the Hoa Son Sugar Factory land area. KCP Vietnam Industrial Co., Ltd. has invested in the plant to utilize the bagasse generated during the sugar production process. The factory has two units of 2x30 MW. The first phase consists of a 30 MW unit which was put into operation in April 2017. As the plant continuously uses residues from the sugar, it operates in parallel with the sugar factory with an input 8,000 tons of biomass per hour. Unit 1 is co-generating electricity and steam for industrial use at the sugar factory. Unit 2 will also operate in parallel with the operation with the sugar plant and will use 10,000 tons of biomass per hour. This unit will only generate electricity.

KCP Phu Yen biomass power plant uses stoker fired boiler technology. Each unit is configured with 1 boiler, 1 steam turbine and 1 generator, and it uses a cooling tower with additional water from Ba river.

The plant has applied a high-performance electrostatic filter (ESP) system to control and ensure the dust content meets environmental standards. Slag ash is used as input to the microbial fertilizer plant next to the Sugar Factory. Waste water treatment is undertaken at a separate waste water treatment system shared with the Sugar Plant. The fuel used for the first phase (1x30 MW) is mainly bagasse from Hoa Son sugar factory. For the 2nd phase (2x30 MW) bagasse from the sugar factory will also be used, but other biomass fuel such as rice husk, coconut and cashew nut shell will also be added.

The main factory area occupies about 12.6 ha. The plant (first unit 30 MW) started construction by the end of 2015, completed and officially put into operation in April 2017. The total investment of the project was 58.45 million $, of which the investment for the first phase is 29.2 million $, equivalent to 1 M$ / MW.

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Data sheets
The following pages contain the data sheets of the technology. All costs are stated in U.S. dollars ($), price year 2016.

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.

The investment in the Vietnam case is low because the KCP plant is located in Sugar factory area so it has the advantage in construction as well as shares some items with the sugar factory.

Technology	Biomass power plant (small plant)								
	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	25	25	25	1	50	1	50		1;5
Generating capacity for total power plant (MWe)	25	25	25	1	50	1	50		1;5
Electricity efficiency. net (%). name plate	32	32	32	25	35	25	35		1;3;7
Electricity efficiency. net (%). annual average	31	31	31	25	35	25	35		1;3;7
Forced outage (%)	7	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
Financial data									
Nominal investment (M$/MWe)	1.7	1.6	1.4	1.3	2.2	1.0	1.7	B	4-8;11
- of which equipment (%)	65	65	65	50	85	50	85		1;2
- of which installation (%)	35	35	35	15	50	15	50		1;2
Fixed O&M ($/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:

1 Ea Energy Analyses and Danish Energy Agency, 2017, "Technology Data for the Indonesian Power Sector - Catalogue for Generation and Storage of Electricity"
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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 India Central Electricity Authority, 2007, "Report on the Land Requirement of Thermal Power Stations".
10 IEA-ETSAP and IRENA, 2015, "Biomass for Heat and Power, Technology Brief".
11 Learning curve approach for the development of financial parameters.

Notes:

A Uncertainty (Upper/Lower) is estimated as +/- 25%.
B Investment costs include the engineering, procurement and construction (EPC) cost. See description under Methodology.

7. MUNICIPAL SOLID WASTE AND LAND-FILL GAS POWER PLANTS

Brief technology description
Municipal solid waste (MSW) is a type of waste 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.

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.

The method of using incineration to convert municipal solid waste to energy is a relatively old method of WtE production. 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.

The caloric value of MSW depends on the composition of the waste. Next table gives the estimated caloric value of MSW components on dry weight basis.

Table 18: Average heat values of MSW components (ref. 2)

Component	Heat 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 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.

Landfill gas 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 is released. Landfill gas consists of approximately 50% methane, 42% carbon dioxide, 7% nitrogen and 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. 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.

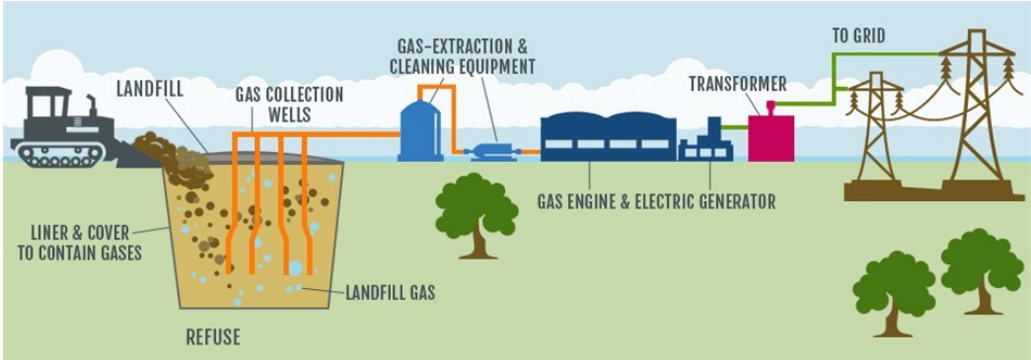

Figure 26: Land-fill gas to energy (ref. 5)

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.

Figure 27: 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 or fuel oil for starting and closing down.

Land-fill gas is the fuel feedstock for the land-fill gas power plants.

Output
For combustion systems, the outputs are electricity and if relevant also heat as hot (> 110 ^{o}C) or warm (<110 ^{o}C) 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 SO_2-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. Therefor 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.

In developing countries like Vietnam, 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
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.

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, several 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 can efficiently convert the energy into liquid or gaseous fuels:

- *Pyrolysis* — MSW is heated in the absence of oxygen at temperatures ranging from 550 to 1300 degrees Fahrenheit. 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 750 to 3000 degrees Fahrenheit. 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)

Table 19: 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

Table 20: 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

* 90% by volume

Examples of current projects

Nam Son waste incineration power plant

Nam Son waste incineration power plant located in Soc Son district, Ha Noi with generating capacity of 1.93 MW. The plant inaugurated in April 2017. The plant used combustion technology, burning waste to generate electricity with a capacity of 75 tons waste per day. The net generating capacity of plant is 1.2 MW. The investment was 29.2 M$, equal the investment rate of 15.1 M$/MW.

Go Cat Land fill gas

Go Cat landfill of garbage with total capacity of 2.4 MW (3 units). This plant funded by the Dutch Government, started construction from 2001 and generated to the grid in 2005. In 2017 a second plant with 7 MW was added to Go Cat.

Developing municipal solid waste power plant in Vietnam faces some challenges:

- There is no local solid waste development plan.
- There are no specific guidelines and regulations on the classification of solid waste at source.
- Most of imported technology is not suitable, the domestic equipment and technology are not complete and synchronized.

- Lack of experiment in management and operation on the classification of solid waste at source.

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The following sources are used:

1. Glover and Mattingly, 2009. ”Reconsidering Municipal Solid Waste as a Renewable Energy Feedstock”, *Issue Brief*, Environmental and Energy Study Institute (ESSI), Washington, USA.
2. Reinhart, 2004. Estimation of Energy Content of Municipal Solid Waste, University of Central Florida, USA.
3. Viva Media Baru. http://www.viva.co.id. Accessed: 1st August 2017.
4. Rawlins et. al., 2014. *Waste to energy in Indonesia*, The Carbon Trust, London, United Kingdom.
5. Advanced Disposal Services. http://www.advanceddisposal.com. Accessed: 1st August 2017.
6. Morton, 2005. ”World Bank Experience in Landfill Gas and Prospects for Indonesia”, *USEPA LMOP Conference*, Baltimore, USA.
7. Kardono, et. al., 2007. ”Landfill Gas for Energy: Its Status and Prospect in Indonesia”, *Proceeding of International Symposium on EcoTopia Science 2007*, ISETS07.
8. http://adriarani.blogspot.co.id/2011/12/bukan-tpa-bantar-gebang.html. Accessed: 12th August 2017.
9. Alternative Resources, Inc., 2008. “Evaluating Conversion Technology for Municipal Solid Waste Management.” Alternative Resources, Inc.
10. Department for Environment, Food, and Rural Affairs, 2004. “Review of Environmental and Health Effects of Waste Management: Municipal Solid Waste and Similar Wastes.” Department for Environment, Food, and Rural Affairs.
11. Alternative Resources, Inc., 2008. “Evaluating Conversion Technology for Municipal Solid Waste Management.” Alternative Resources, Inc.
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.

Data sheets

The following pages contain the data sheets of the technology. All costs are stated in U.S. dollars ($), price year 2016.

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)									
Financial data									
Nominal investment (M$/MWe)	8.7	8.1	7.2	6.5	9.0	5.4	9.0	C	1
- of which equipment (%)	5.2	4.4	3.6	3.9	4.5	2.7	4.5		1
- of which installation (%)	3.6	3.7	3.6	2.7	4.5	2.7	4.5		1
Fixed O&M ($/MWe/year)	243,700	224,800	193,500	195,000	304,600	154,800	241,900	C	1
Variable O&M ($/MWh)	24.1	23.4	22.6	18.1	28.2	16.9	28.2	C	1
Start-up costs ($/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 financial 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 calorie 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
Energy/technical data				Lower	Upper	Lower	Upper		
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)									
Financial data									
Nominal investment (M$/MWe)	2.5	2.5	2.5	2.3	2.8	2.3	2.9	A	3
- of which equipment (%)	70	70	70	70	80	70	80		5
- of which installation (%)	30	30	30	30	30	30	30		5
Fixed O&M ($/MWe/year)	125,000	125,000	125,000	113,640	137,500	113,636	143,750	A	3
Variable O&M ($/MWh)									
Start-up costs ($/MWe/start-up)									

References:

1 OJK, 2014, "Clean Energy Handbook for Financial Service Institutions", Indonesia Financial Service Authority, Jakarta, Indonesia
2 Renewables Academy" (RENAC) AG, 2014, "Biogas Technology and Biomass", Berlin, Germany.
3 IEA-ETSAP and IRENA, 2015. "Biomass for Heat and Power, Technology Brief".
4 Ea Energy Analyses and Danish Energy Agency, 2017, "Technology Data for the Indonesian Power Sector - Catalogue for Generation and Storage of Electricity"

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

Notes:

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

8. 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 and ref. 2).

Feedstocks of biogas production in Vietnam 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 is discussed in chapter 8.

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 can 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 – 38°C (mesophilic) or 55 – 58°C (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.

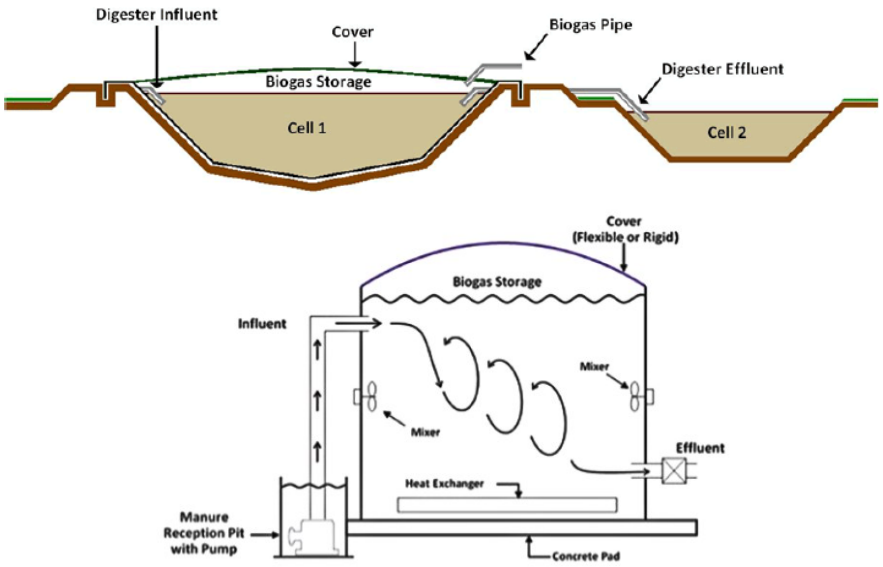

Figure 28: Covered lagoon and CSTR biogas plants (ref.3)

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 m^3 methane per tonne, while the gas output typically is 30 – 130 m^3 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.

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).

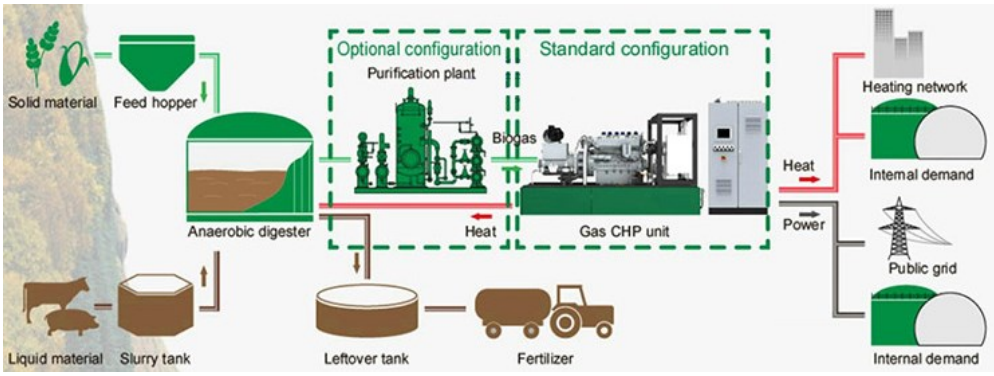

Figure 29: Biogas CHP working diagram (ref. 5)

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. In this case the gas needs to be treated to comply with the standards of the gas grid. The digested biomass can be used as fertilizer in crop production.

Typical capacities
Medium: 10 – 50 MW.
Small: 1 – 10 MW.

Ramping configurations
Like 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
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 kilowatts (kW) of electricity while maintaining emission levels that meet the California Air Resources Board's (ARB) strict regulations (ref. 9).

Examples of current projects
The largest biogas power plant in the world is located in Finland. It has an installed capacity of 140 MW. Fuelled 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)

In Vietnam, the use of biogas at large scale to generate power is still difficult, High investment cost of biogas power plants will lead to a limited deployment in Vietnam.

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Data sheets
The follow pages contain the data sheets of the technology. All costs are stated in U.S. dollars ($), price year 2016.

Technology	Biogas power plant								
	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	1	1	1						3
Generating capacity for total power plant (MWe)	1	1	1						3
Electricity efficiency. net (%). name plate	35	35	35						4
Electricity efficiency. net (%). annual average	34	34	34						4
Forced outage (%)	5	5	5						1
Planned outage (weeks per year)	5	5	5						1
Technical lifetime (years)	25	25	25						7
Construction time (years)	1.5	1.5	1.5						7
Space requirement (1000 m^2/MWe)	70	70	70						12
Additional data for non-thermal plants									
Capacity factor (%). theoretical	-	-	-	-	-	-	-		
Capacity factor (%). incl, outages	-	-	-	-	-	-	-		
Ramping configurations									
Ramping (% per minute)	20	20	20	10	30	10	30		11
Minimum load (% of full load)	20	30	15	30	50	10	40		10
Warm start-up time (hours)									
Cold start-up time (hours)									
Environment									
PM 2,5 (mg per Nm^3)									
SO_2 (degree of desulphuring. %)									
NO_X (g per GJ fuel)									
Financial data									
Nominal investment (M$/MWe)	2.8	2.6	2.2	2.1	3.5	1.7	2.8	A	3;5;8;9
- of which equipment (%)	65	65	65	50	85	50	85		
- of which installation (%)	35	35	35	15	50	15	50		
Fixed O&M ($/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 Ea Energy Analyses and Danish Energy Agency, 2017, "Technology Data for the Indonesian Power Sector - Catalogue for Generation and Storage of Electricity"
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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%.

9. DIESEL POWER PLANT

Brief technology description
The basic feature of a diesel power plant is a diesel engine (compression ignition engine) coupled directly to a generator.

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 MW_e 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.

Typical capacities
Up to approx. 300 MW_e. Large diesel power plants (>20 MW_e) would often consists of multiple engines in the size of 1-23 MW_e (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, ref 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. Simple and easy to repair.

Disadvantages

- Diesel engines cannot be used to produce high-pressure steam (as turbines). Approx. 50% of the waste heat is released at lower temperatures.
- Expensive fuel.
- Low efficiency / high operational costs
- High environmental impact from NO_x and SO_2 emissions.

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 NO_x emissions.

With SCR technology, NO_x 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 are a mature technology and only gradual improvements are expected.

According to the IEA's 2 and 4 DS 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 0.86 mill. $/ MW_e (Ref 7).

In the data sheet we consider a MW_e oil fired power plant consisting of 5 units, at 20 MW_e each and an estimated price of 0.8 mill. $/ MW_e.

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 Faroe Islands. http://www.bwsc.com/News---Press.aspx?ID=530&PID=2281&Action=1&NewsId=206

Data sheets

The following pages contain the data sheets of the technology. All costs are stated in U.S. dollars ($), price year 2016. The *uncertainty* is related to the specific parameters and cannot be read vertically – meaning a product with lower efficiency does not have the lower price or vice versa.

Technology	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						
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
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 Ea Energy Analyses and Danish Energy Agency, 2017, "Technology Data for the Indonesian Power Sector - Catalogue for Generation and Storage of Electricity"

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 exhausts 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 dependent on the fuel composition.
D Investment costs include the engineering, procurement and construction (EPC) cost. See description under Methodology.

10. GEOTHERMAL POWER PLANT

Brief technology description
Based on its reservoir temperatures, Hochstein (1990) divided geothermal systems into three systems as the following (ref. 1):

1. Low temperature geothermal systems which have reservoir temperature ranges less than 125°C (low enthalpy).
2. Medium temperature geothermal systems which have reservoir temperature ranges between 125°C and 225°C (medium enthalpy).
3. High temperature geothermal systems which have reservoir temperature ranges higher than 225°C (high enthalpy).

Geothermal to electrical power conversion systems typically in use in the world today may be divided into four energy conversion systems, which are:

- Direct steam plants; used at vapor-dominated reservoirs; dry saturated or slightly superheated steam with temperature range from 320°C down to some 200°C.
- Flashed steam plants; used at water-dominated reservoirs with temperatures greater than 182°C
    - Single flash plants; only high-pressure flash steam
    - Double flash plants; low and high-pressure flash steam
- Binary or twin-fluid system (based upon the Kalina or the Organic Rankin cycle); resource temperature range between 107°C to about 182°C.
- Hybrid; a combined system comprising two or more of the above basic types in series and/or in parallel.

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. They are generally manufactured in output module sizes of the following power ratings: 20 MW to 110 MW (the largest currently manufactured geothermal turbine unit is 117 MW). Binary type low/medium temperature units, such as the Kalina Cycle or Organic Rankin Cycle type, are typically manufactured in smaller modular sizes, i.e. ranging between 1 MW and 10 MW in size. Larger units specially tailored to a specific use are, however, available typically at a somewhat higher price.

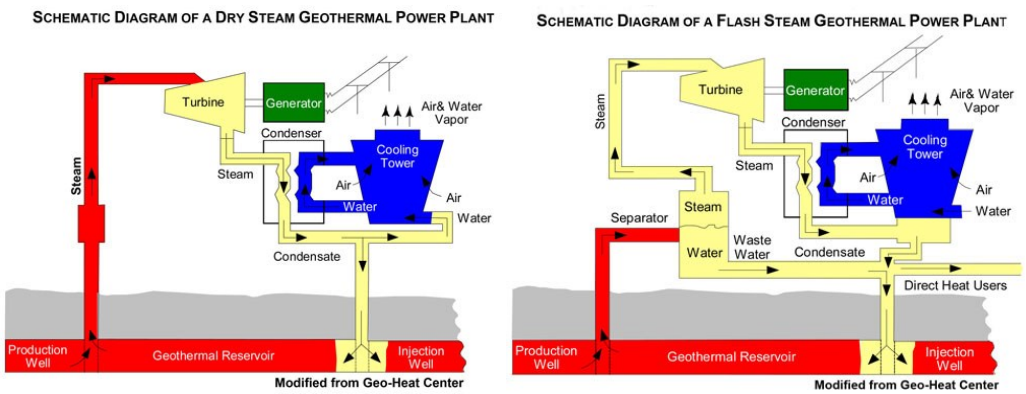

Figure 30: Direct and single flashed steam plants (ref. 7)

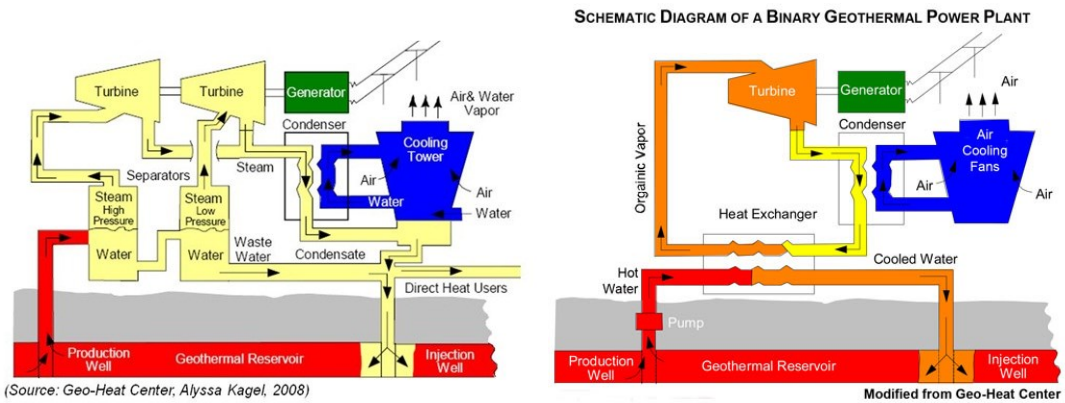

Figure 31: Double flashed and binary steam plants (ref. 7)

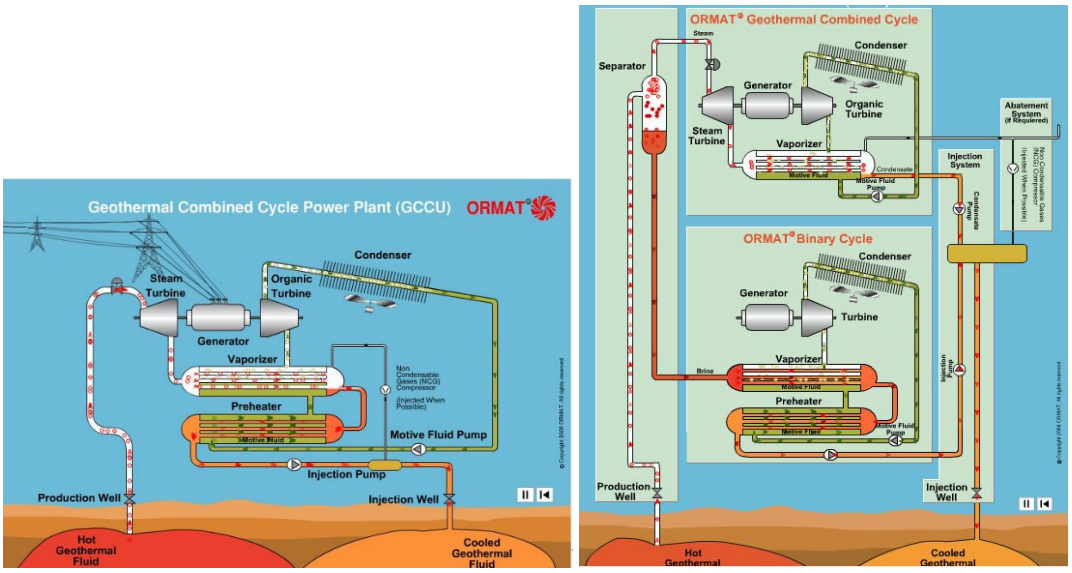

Figure 32: Hybrid/Combined Cycle plant (ref. 8)

The total capacity of geothermal power plants installed in 2015 in Indonesia was 1438 MW (ref. 2). In the same year, geothermal power plants have generated electricity of about 10 TWh. This equals to an average capacity factor of 80%. 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 volcanic-type systems.

In Kenya 636 MW of geothermal capacity is in operation. Most is of the direct type (ref. 13).

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

Output
Electricity and Heat.

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 common).
- Small ecological footprints.
- Almost zero liquid pollution with re-injection of effluent liquid.
- 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-life time.
- Potential for combination with heat storage.
- Geothermal is distinct from variable renewables, such as wind and solar, because it can provide consistent electricity throughout the day and year.

Disadvantages:

- No security for success before the first well is drilled and the reservoir has been tested (ref. 11). / high risk investment
- 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.

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, 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 hydrogen sulphide in humans can range from 0.0005 to 0.3 ppm.

Employment
During construction, the development of Indonesian 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 work force. 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, North Sulawesi site has been elaborated. 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, which shows the technical concept of the demonstration plant, it can be seen that 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 kW_e. The auxiliary power consumption is estimated to be lower than 20%.

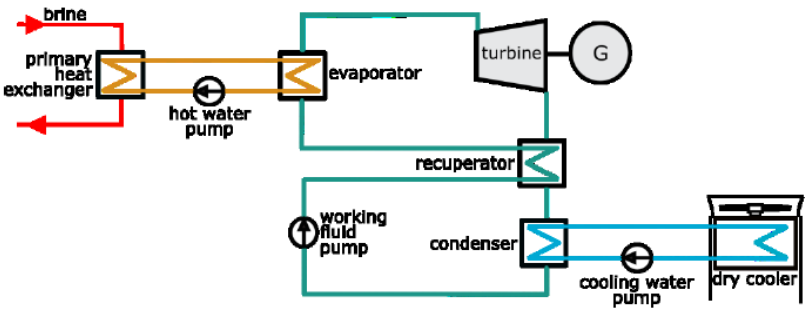

Figure 33: Technical concept of the demonstration power plant (ref. 4)

Examples of current projects

Vietnam lies on the contact between the East Sea basin and the continental ridge of Southeast Asia. More than 300 hot mineral manifestations with temperatures up to 105°C have been identified. Furthermore, more than 100 hot water resources with temperatures up to 148°C have been identified (ref. 12).

So far very limited use of geothermal has taken place in Vietnam. High investment cost and lack of experience may be part of the reason.

Additional remarks

The conversion efficiency of geothermal power developments is generally lower than that of 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.

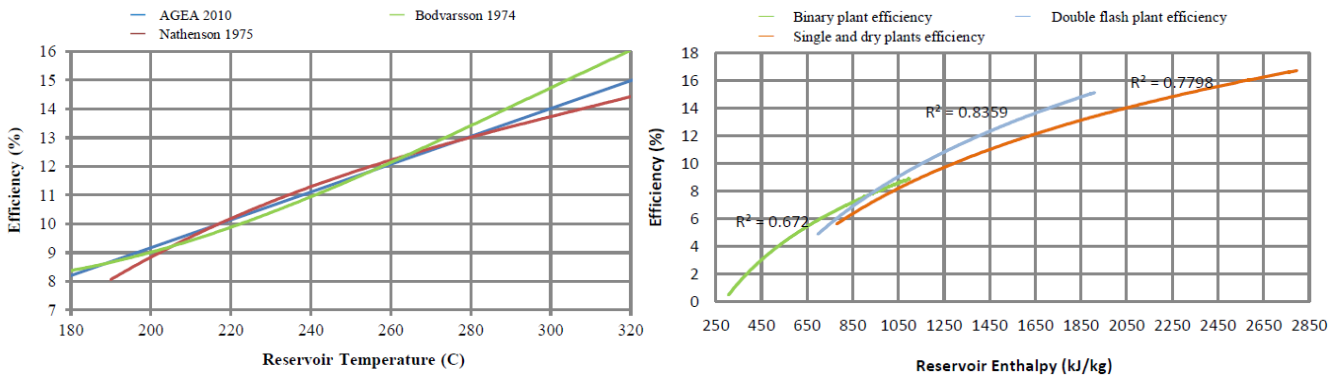

Figure 34: Geothermal plant efficiency as a function of temperature and enthalpy (ref. 5)

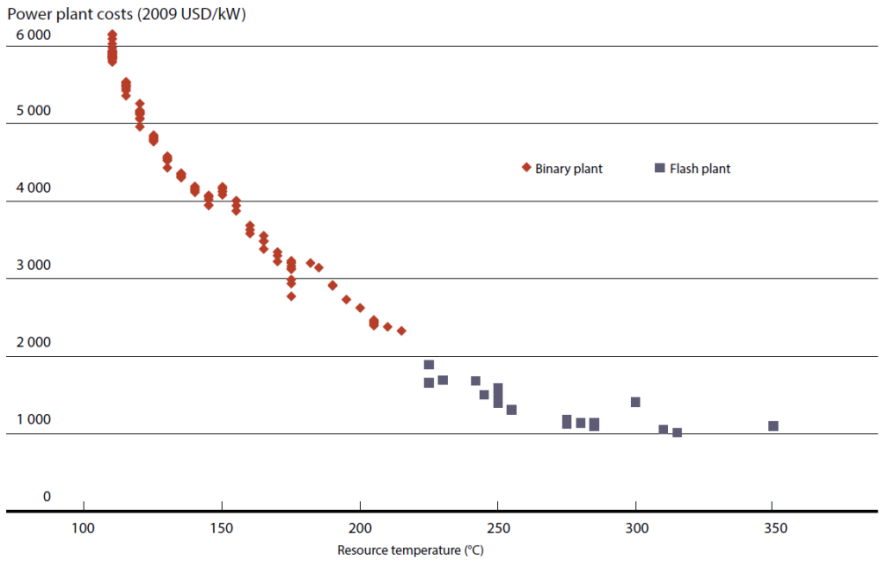

Figure 35: Indicative power plant only costs for geothermal projects by reservoir temperature (ref. 10). The power plant unit stands for around 40-50% of the total capital costs.

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Data sheets

The following pages contain the data sheets of the technology. All costs are stated in U.S. dollars ($), price year 2016.

Technology	Geothermal power plant - small system (binary or condensing)								
	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
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
Financial data									
Nominal investment (M$/MWe)	4.5	4.2	3.8	3.4	5.7	2.9	4.8	C;D;E	1;2;4;8
- of which equipment (%)	60	60	60	40	70	40	70		3
- of which installation (%)	40	40	40	30	50	30	50		3
Fixed O&M ($/MWe/year)	20,000	18,500	16,900	15,000	25,000	12,700	21,100	C;D	1;4
Variable O&M ($/MWh)	0.37	0.34	0.31	0.28	0.46	0.23	0.39	C;D	1;4
Start-up costs ($/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 H2S. From Minister of Environment Regulation 21/2008 this shall be below 35 mg/Nm3.
C Uncertainty (Upper/Lower) is estimated as +/- 25%.
D Investment cost are including Exploration and Confirmation costs (see under Technology specific data).
E Investment costs include the engineering, procurement and construction (EPC) cost. See description under Methodology.

Technology	Geothermal power plant - large system (flash or dry)								
	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	55	55	55	30	500	30	500		1
Generating capacity for total power plant (MWe)	110	110	110	30	500	30	500		1
Electricity efficiency. net (%). name plate	16	17	18	8	18	10	20	A	5
Electricity efficiency. net (%). annual average	15	16	17	8	18	10	20	A	5
Forced outage (%)	10	10	10	5	30	5	30		1
Planned outage (weeks per year)	4	4	4	2	6	2	6		1
Technical lifetime (years)	30	30	30	20	50	20	50		1
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
Financial data									
Nominal investment (M$/MWe)	3.5	3.2	2.9	2.6	4.4	2.2	3.7	B;D;E	1;2;3;4
- of which equipment (%)	60	60	60	40	70	40	70		3
- of which installation (%)	40	40	40	30	50	30	50		3
Fixed O&M ($/MWe/year)	18,000	16,700	15,200	13,500	22,500	11,400	19,000	B;D	1;4
Variable O&M ($/MWh)	0.25	0.23	0.21	0.19	0.31	0.16	0.26	B;D	1;4
Start-up costs ($/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 Ea Energy Analyses and Danish Energy Agency, 2017, "Technology Data for the Indonesian Power Sector - Catalogue for Generation and Storage of Electricity"
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 efficiency will give a lower investment cost per MW. These large units are assumed to be flash 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 H2S. From Minister of Environment Regulation 21/2008 this shall be below 35 mg/Nm3.
D The learning rate is assumed to impact the geothermal specific equipment and installation. The power plant unit (i.e. the turbine and pump) is assumed to have very little development. From Ref. 3 it is assumed that half of the investment costs are on the geothermal specific equipment.
E Investment costs are including Exploration and Confirmation costs (see under Technology specific data).

11. HYDRO PUMPED STORAGE

Brief technology description
Pumped storage plants (PSPs) use water that is pumped from a lower reservoir into an upper reservoir to charge the storage. To discharge the storage, 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 it 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).

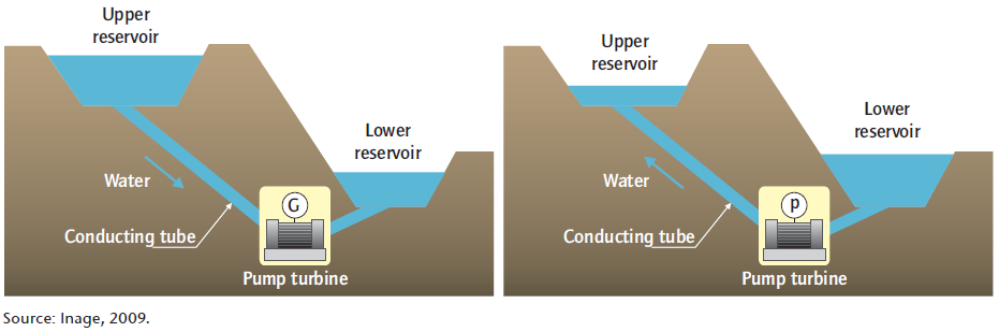

Figure 36: Pumped storage hydropower plants (ref. 2)

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 often a cheap way of storing large amounts of electricity. 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).

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 are able to cope with high generation-driven fluctuations and can provide active power within a short period of time.

Advantages/disadvantages
Advantage:

- The water can be reused over and over again and 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.
- 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 hydropower 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.

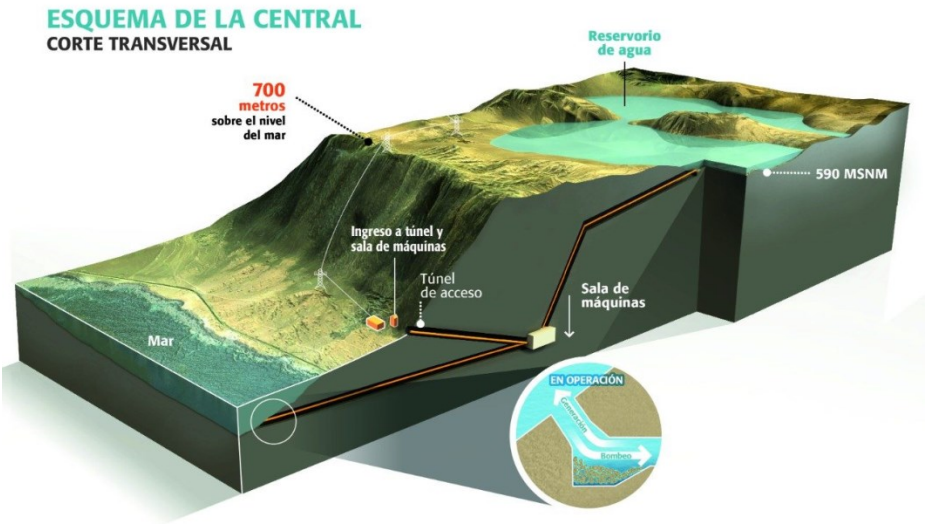

Figure 37: A 300 MW sea water pumped storage hydropower plan in Chile (ref. 13)

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

Bac Ai pump storage plant

Bac Ai is the first Vietnamese pumped storage power plant and is in the progress of technical design. The total capacity of the plant is 1,200 MW, with 4 units of 300 MW. According to Power Master Plan 7 (revised), Bac Ai PSPP will be put into operation in 2023- 2025. The upper reservoir will be built on top of Da Den Mountain, with dam height of 72 m, the normal rising water level is 603 m and the effective volume is 9 million m^3. The lower reservoir will use water from Song Cai reservoir belonging to Tan My irrigation system with a dam height of 38.4m, the normal water level is 193 m and effective volume is 200 million m^3, available for Bac Ai PSPP is 10 million m^3. The designing water head is 403m and the maximum discharge flow is 248 m^3/s. The plant is going to use Francis turbines and the round cycle efficiency is 70%. The total investment of Bac Ai is expected to be 883 M$ ($2016, the administration, consultancy, project management, site preparation cost, the taxes and interest during construction are not included), equal to the investment rate of 0.74 M$/ MW_e. The total capital (including these components) was 980 million $, corresponding to 0.816 M$/$MW_e$ (Ref. 17).

Pumped storage plants, such as the Grand Maison power station in France, can ramp up to 1,800 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. In 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).

Indonesia has presented plans for building the country's first pumped storage hydropower plant. The power plant is planned to 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 2019.

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Data sheets

The following pages contain the data sheets of the technology. All costs are stated in U.S. dollars ($), price year 2016.

Technology	Hydro pumped storage								
	2020	2030	2050	Uncertainty (2020)		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)	1,000	1,000	1,000	100	4,000	100	4,000		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	0	0	0	0		
SO_2 (degree of desulphuring. %)	0	0	0	0	0	0	0		
NO_X (g per GJ fuel)	0	0	0	0	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 Ea Energy Analyses and Danish Energy Agency, 2017, "Technology Data for the Indonesian Power Sector - Catalogue for Generation and Storage of Electricity"
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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 costs include the engineering, procurement and construction (EPC) cost. See description under Methodology.

12. LIHIUM-ION BATTERY

A lithium-ion battery or Li-ion battery (abbreviated as LIB) can store electric energy as chemical energy. Both non-rechargeable and rechargeable LIBs are commercially available. The non-rechargeable LIBs (also called primary cells) have long shelf-life and low self-discharge rates and are typically fabricated as small button cells for e.g. portable consumer electronics, arm watches and hearing aids. Rechargeable LIBs (also named secondary cells) are applied in all kinds of consumer electronics and is currently entering new markets such as electric vehicles and large-scale electricity storage. The rechargeable LIBs can be used to supply system level services such as primary frequency regulation, voltage regulation and load shifting, as well as for local electricity storage at individual households. Below we only focus on the rechargeable LIBs[13].

A LIB contains two porous electrodes separated by a porous membrane. A liquid electrolyte fills the pores in the electrodes and membrane. Lithium salt (e.g. $LiPF_6$) is disolved in the electrolyte to form Li^+ and PF_6^- ions. The ions can move from one electrode to the other via the pores in the electrolyte and membrane. Both the positive and negative electrode materials can react with the Li^+ ions. The negative electrode in a LIB is typically made of carbon and the positive of a Lithium metal oxide. Electrons cannot migrate through the electrolyte and the membrane physically separates the two electrodes to avoid electrons crossing from the negative to the positive electrode and thereby internally short circuiting the battery. The individual components in the LIB are presented in the figure below.

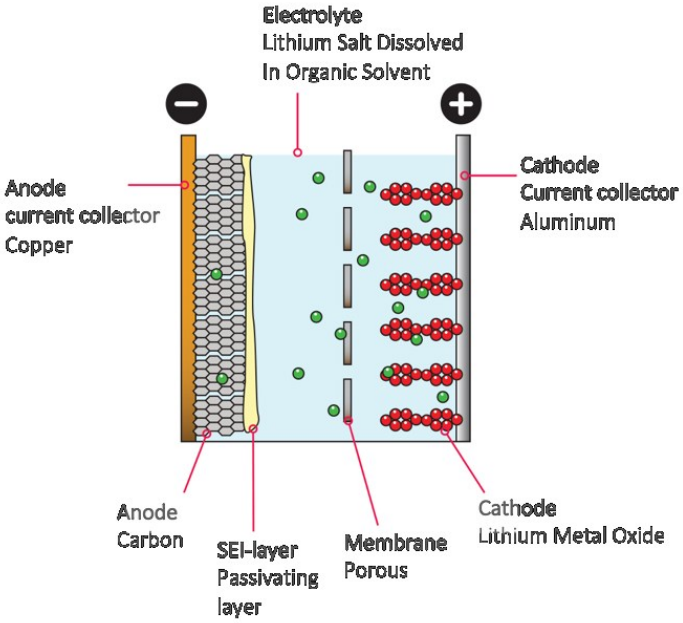


Figure 38: Schematic diagram of a typical LIB system displaying the individual components in the battery.

When the two electrodes are connected via an external circuit the battery start to discharge. During the discharge process electrons flow via the external circuit from the negative electrode to the positive. At the same time Li^+ ions leaves the negative electrode and flows through the electrolyte towards the positive electrode where they react with the positive electrode. The process runs spontaniously since the two electrodes are made of different materials. In popular terms the positive electrode "likes" the electrons and the Li^+ ions better than the negative electrode.

The energy released by having one Li^+ ion, and one electron, leaving the negative electrode and entering the positive electrode is measured as the battery voltage times the charge of the electron. In other words the battery voltage - also known as the *electromotive force*: *EMF* - measures the energy per electron released during the discharge process. *EMF* is typically a around 3-4 Volts and depends on the LIB cell

[13] This chapter is taken from the draft chapter from the Danish Technology catalogue. It is written by Rasmus Rode Mosbæk and Søren Højgaard Jensen, Hybrid Greentech ApS.

chemistry, the temperature and the state of charge (SOC – see below). When e.g. a light bulb is inserted in the external circuit the voltage primarily drops across the light bulb and therefore the energy released in the LIB is dissipated in the light bulb. If the light bulb is substituted with a voltage source (e.g. a power supply) the process in the battery can be reversed and thereby electric energy can be stored in the battery.

The discharge and charge process is outlined in figur below. The battery is fully discharged when nearly all the Lithium have left the negative electrode and reacted with the positive electrode. If the battery is discharged beyond this point the electrode chemistries become unstable and starte degrading. When the LIB is fully discharged the *EMF* is low compared to when it is fully charged. Each LIB chemistry has a safe voltage range for the *EMF* and the endpoints of the range typically define 0% and 100% state of charge (SOC). The discharge capacity is measured in units of Ampere times hours, Ah, and depends on the type and amount of material in the electrodes.

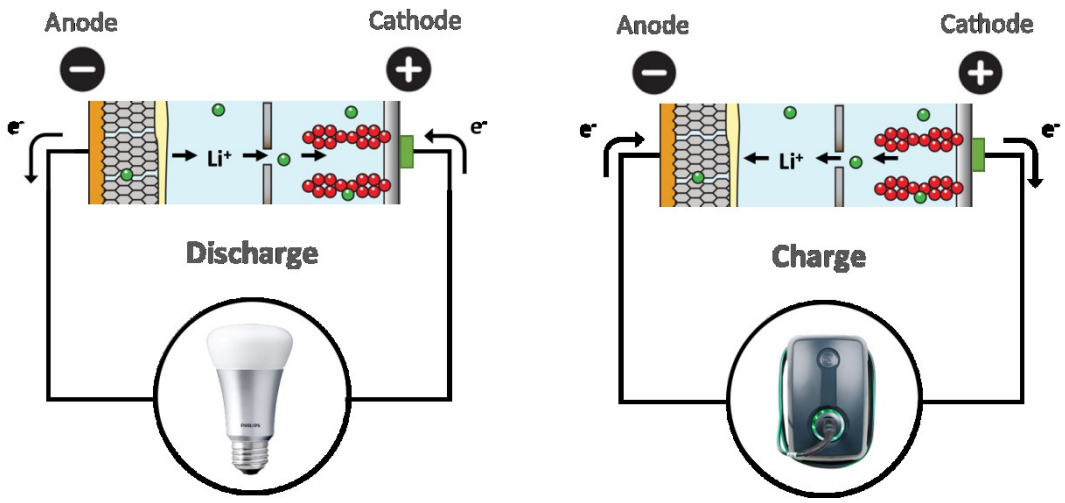


Figure 39: Schematic diagram of a LIB system in charge and discharge mode. During discharge the green Li^+ ions moves from the negative electrode (left side) to the positive electrode. The process is reversed during charge mode (right side).

The first lithium batteries were developed in the early 1970'ies and Sony released the first commercial lithium-ion battery in 1991. During the '90s and early 2000s the LIBs gradually matured via the pull from the cell-phone market. The Tesla Roadster was released to customers in 2008 and was the first highway legal serial production all-electric car to use lithium-ion battery cells. Further, around 2010 the LIBs expanded into the energy storage sector.

Lithium-ion chemistries

The table below shows a comparison of the three most widely used LIB chemistries for grid-connected LIB systems and the major manufactures. Other LIB chemistries such as LCO, LMO and NCA are not used for grid electricity storage and are therefore not included in the table. The numbers in the table are taken from cell manufactures, product or system suppliers. NMC is the most widely used of the three chemistries due to the increased production volume and lower prices lead by the automotive sector. The NMC battery has a high energy density but uses cobalt. The environmental challenges in using cobalt are described in the section: "Environment".

The LFP battery do not use cobalt in the cathode, but are not as widely used as NMC, and are therefore generally higher priced, primarily due to the lower production volumes.

Both NMC and LFP batteries have graphite anodes. The main cause for degradation of NMC and LFP LIBs is graphite exfoliation and electrolyte degradation which in particular occur during deep cycling.

LTO LIBs are the most expensive cell chemistry of the three. In LTOs the graphite anode is replaced with a Lithium Titanate anode. The cathode of a LTO battery can be NMC, LFP or other battery cathode chemistries.

The LTO battery is characterized by long calendar lifetime and high number of cycles.

Table 21: A comparison of four widely used LIB chemistries.

Short name	Name	Anode	Cathode	Energy density Wh/kg	Cycles	Calendar life	Major manufactures	References
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	1-5
LFP	Lithum Iron Phosphate	Graphite	$LiFePO_4$	50-130	6000-8000	10-20 years	BYD/Fenecon Fronius/Sony*	6, 7
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	1, 3, 4, 8

**Residential energy storage system. All other systems are multi-MWh size.*

Lithium-ion battery packaging

The most common packaging styles for LIB cells are presented in the figure below.. Examples are provided in the figure below. The figure (a) show a schematic drawing of a cylindrical LIB cell. Cylindrical cells find widespread applications ranging from laptops and power tools to Tesla's battery packs. The figure (a) shows Tesla's 21700 cylindrical LIB cell which is 21 mm in diameter and 70 mm in length. The cell is produced in Tesla's Gigafactory 1 for Tesla Model 3 (ref. 9). The figure (b) outline a coin LIB cell. Coin cells are usually used as primary cells in portable consumer electronics, watches and hearing aids. Since they are not used for secondary cells (rechargeable) in grid-connected LIB Battery Energy Storage Systems they are not described further in this text. The figure (c) displays a schematic drawing of a prismatic LIB cell. Prismatic LIB cells are often used in industrial applications and grid-connected LIB Battery Energy Storage Systems. The Samsung SDI prismatic LIB cell is shown in the figure (b). This cell type is used in the BMW i3 (ref. 10). The figure (d) shows a schematic drawing of a pouch LIB cell. The figure (c) shows an LG Chem pouch NMC LIB cell used in LG Chem's grid-connected LIB Battery Energy Storage Systems. Pouch LIB cells are also used in electric vehicles such as the Nissan Leaf (ref. 11).

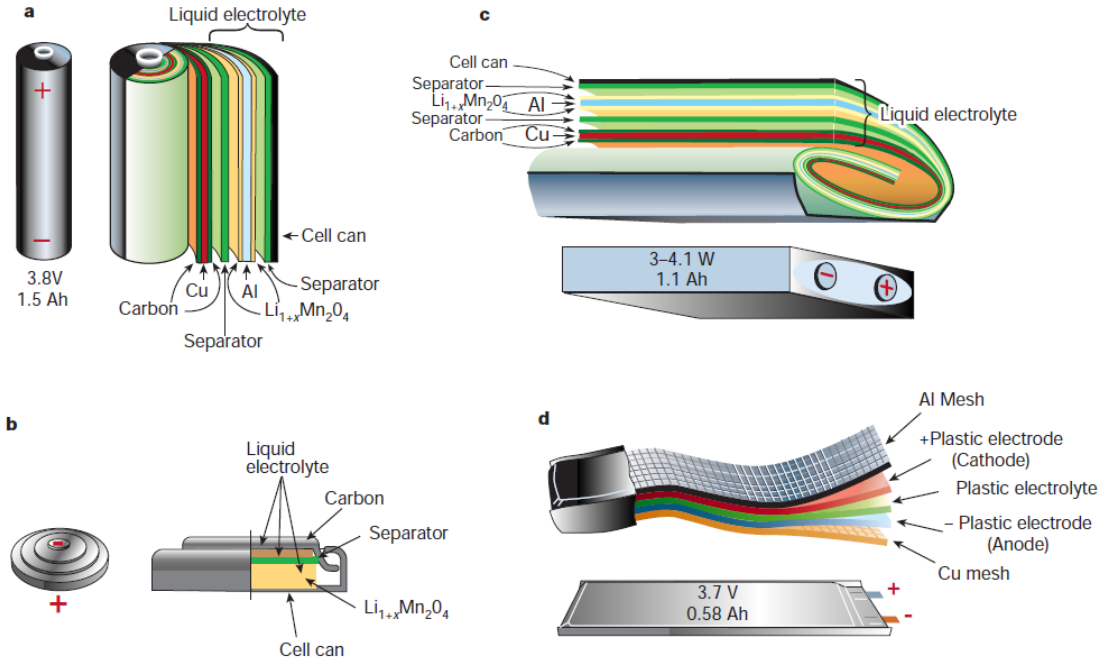


Figure 40: Schematic drawing showing the shape, packaging and components of various Li-ion battery configurations (ref. 12). (a) Cylindrical; (b) coin; (c) prismatic; and (d) pouch.

Figure 41: Examples of LIB cells. (a) Tesla 21700 cylindrical NMC LIB cell. (b) Samsung SDI prismatic LIB cells. (c) LG Chem pouch NMC LIB cell. (Ref. 12 to 15)..

Components in a lithium-ion battery energy storage system

The figure below provides an overview of the components in a LIB storage system with interface to the power grid. In LIB storage systems battery cells are assembled into modules that are assembled into packs. The battery packs include a Battery Management System (BMS). The BMS is an electronic system that protects the cells from operating outside the safe operating area. A Thermal Management System (TMS) regulates the temperature for the battery and storage system. The TMS depends on the environmental conditions, e.g. whether the system is placed indoor or outdoor. Further an Energy Management System (EMS) controls the charge/discharge of the grid-connected LIB storage from a system perspective. Depending on the application and power configuration the power conversion system may consist of one or multiple power converter units (DC/AC link). For system coupling a transformer may be needed for integration with higher grid voltage levels. The grid integration provides services to the grid such as increased reliability, load shifting, frequency regulation etc. The services are described further below in the section “Regulation ability and other system services”. Value generation and profit is created by selling the services to grid Transmission System Operators (TSOs). Appropriate sizing of the battery and power conversion systems is essential to maximize the revenue.

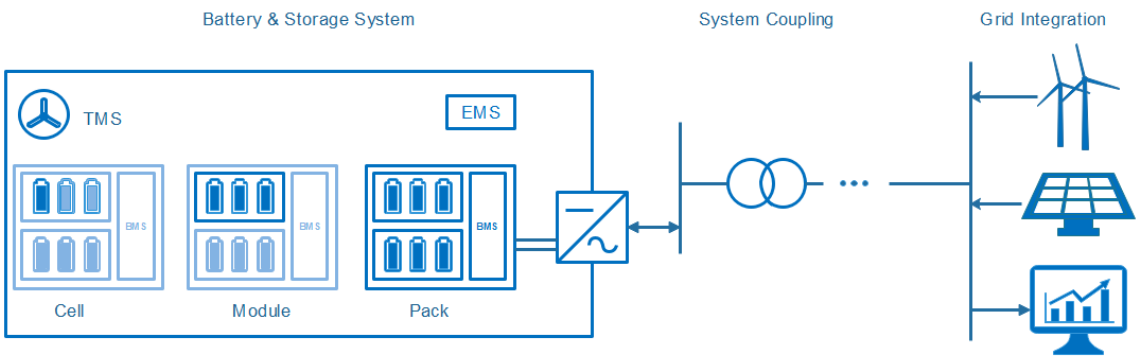


Figure 42: Schematic drawing of a battery storage system, power system coupling and grid interface components. Keywords highlight technically, and economically relevant aspects. Modified from (ref. 16).

Input/Output
Input and output are both electricity. Electricity is converted to electrochemical energy during charge and converted back to electricity during discharge.

Energy efficiency and losses
The losses in a LIB can be divided in operational and standby losses. The operational losses occur when energy is discharged or charged to/from the grid. It includes the conversion losses in the battery and the power electronics.

When the LIB is not operated its voltage U equals the EMF. However, during discharge or charge the battery voltage U change due to current I passing the internal resistance R_i in the LIB. The voltage change ΔU can be described using Ohms law

$$\Delta U = U - EMF = R_i I \quad (1)$$

and the loss in the internal resistance is defined as

$$P_{loss} = \Delta U I = R_i I^2 \quad (2)$$

Equation (2) explains how the loss increases with increasing current.
The LIB provides a DC current during discharge and needs a DC current input for charging. Before the electricity is sent to the grid the inverter converts the DC current to AC. The inverter loss typically increases gradually from around 1% to 2% when increasing the relative conversion power from 0% to 100% (ref 17).

Unwanted chemical reactions cause internal current leakage in the LIB. The current leakage leads to a gradual self-discharge during standby. The self-discharge rate increases with temperature and the graph below shows the remaining charge capacity as function of time and temperature for a LIB. The discharge rate is the slope of the curve and is around 0.1% per day at ambient temperature.

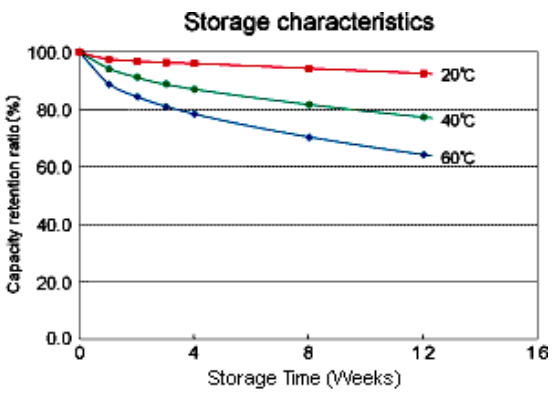


Figure 43: Remaining charge capacity for a typical LIB as function of storage time (ref. 18).

Besides the self-discharge in the cell, a LIB electricity storage system requires power to operate the auxiliary balance of plant (BOP) components. The relative energy loss to the BOP components depends on the application, and a careful operation strategy is important to minimize their power consumption (ref. 17). The standby loss E_{stb} is the sum of the energy losses during standby due to self-discharge and power consumption in the BOP components.

The conversion roundtrip efficiency of the LIB cell is the discharged energy divided with the charged energy. The battery conversion efficiency decreases with increasing current since the P_{loss} increases. An example of a LIB cell conversion efficiency is shown in the figure below. The C-rate is the inverse of the time it takes to discharge a fully charged battery. At a C-rate of 2 it takes ½ hour and at a C-rate of 6 it takes 10 minutes.

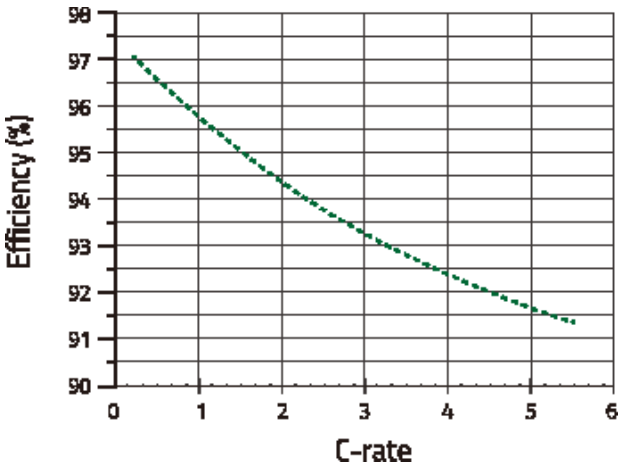


Figure 44: Conversion round trip efficiency vs. C-rate for one of Kokam's NMC-based lithium polymer batteries (ref. 19).

The system conversion roundtrip efficiency $\eta_{\text{Conversion}}$ considers losses which occur on the conversion path from the energy charged $E_{\text{Charge,AC}}$ and the energy discharged $E_{\text{Discharge,AC}}$ from/to the grid. It includes the conversion losses in the battery and power electronics
and can be written as

$$\eta_{\text{Conversion}} = \frac{E_{\text{Discharge,AC}}}{E_{\text{Charge,AC}}} \tag{3}$$

The total roundtrip efficiency η_{Total} further includes the standby losses:

$$\eta_{\text{Total}} = \frac{E_{\text{Discharge,AC}}}{E_{\text{Charge,AC}} + E_{stb}} \tag{4}$$

Here E_{stb} denotes the energy required from the grid to continuously operate BOP and maintain state of charge. The various types of losses makes η_{Total} heavily dependent on the application. As an example, an 11 MW/4.4 MWh LIB system was installed in Maui, Hawaii for wind ramp management, essentially smoothing the output of a 21 MW wind farm (ref. 20). The total roundtrip efficiency for this system is around 80 % (ref. 21). Lazard uses an estimate of 85% (ref. 22). To summarize, the total roundtrip loss typically consists of 2-5% related to the cell, 2-4% to the power electronics and the rest to standby losses.

Regulation ability and other system services

Grid-connected LIBs can absorb and release electrical energy fast. The response time of grid-connected LIBs are strongly dependent on control components, EMS, BMS and TMS as well as the power conversion system.

The relatively low electricity storage costs makes grid-connected LIB BESS (Battery Energy Storage System) suitable for a broad range of applications (ref. 23) such as *peak load shaving* where the BESS provides or consumes energy to reduce peaking in a power system. In relation to this BESS can promote *renewable integration*, e.g. time or load shifting of photovoltaic power from day to night. Further the BESS can provide *transmission congestion relief* where locally deployed BESS reduces the load in the transmission and distribution system. In this way the BESS can help defer expensive upgrades of the transmission and distribution network.

The fast response time enables the use of BESS for a broad range of primary control provisions. These include *Frequency regulation* where the BESS are used to alleviate deviations in the AC frequency. The BESS can also be used to improve network *reliability* by reacting immediately after a contingency. Here the BESS can help maintaining stability in the power system until the operator has re-dispatched generation. Moreover, the BESS can effectively be used for *black-starting* distribution grids and BESS systems are suitable for enhancing the *power quality* and reducing *voltage deviation*s in distribution networks. The BESS can further be used to provide *spinning reserves* and regulate *active and reactive power* thereby improving the network voltage profile. This can improve the integration of renewable energy because it reduces the events triggering the protections of the inverters.

Typical storage period
Several aspects of the LIB technology put an upper limit to the feasible storage period. The self-discharge rate makes storage periods of several months unfeasible. The BOP power for standby operation adds parasitic losses to the system which further limits the feasible standby time. Unwanted chemical reactions in the LIB gradually degrade the battery and limit the calendar lifetime. This calls for shorter storage periods in order to obtain enough cycles to reach positive revenue.

For LIBs the total number of full charge-discharge cycles within the battery lifetime is limited between a few thousands up to some ten-thousands. The exact number depends on the chemistry, manufacturing method, design and operating conditions such as temperature, C-rate and calendar time. This impacts the type of suitable applications. For instance, due to the different degree of usage, the LTO chemistry may find more use on the FCR-N[14] market while others like NMC may be preferred for the FCR-D market.

Until now the majority of the current LIB systems have been deployed to perform fast reactive renewables smoothing and firming with storage periods ranging from seconds to minutes (ref. 25). But more recently, the systems are increasingly used for renewables time shifting with typical storage periods of a few hours (ref. 17 and 25).

Space requirement
The racks and battery packs are assembled in containers and the energy per 40 feet container is 4-6 MWh for NMC batteries (ref. 2 and 24). The foot-print of a 40-feet container is 29.7 m^2. This gives a space requirement around 5-7.5 MWh/m^2.

Advantages/disadvantages
Within the last decade the commercial interest for electricity storage using LIB systems has increased dramatically. The production volume is still limited and there is a promising potential for cost reductions through upscaling. The technology is stand-alone and requires a minimum of service after the initial installation.

Containers come in standard sizes. For small systems this impacts the LIB system CAPEX, however when the system size exceeds several container units, the price can be considered fairly linear. Compared to e.g. fuel cell technology the CAPEX per storage capacity is relatively high. This is because

[14] FCR-N: Frequency Containment Reserve for Normal operation. FCR-D: Frequency Containment Reserve for Disturbances

the electricity is stored in the battery electrodes whereas for fuel cells the electricity is stored as a separate fuel. The relatively high energy specific CAPEX combined with the gradual self-discharge and parasitic losses in the BOP make the technology less attractive for long-term storage beyond a few days.

Environment

A US-EPA report stated in 2013 that across the battery chemistries, the global warming potential impact attributable to LIB production including mining is substantial (ref 26). More specifically a recent review on life-cycle analysis (LCA) of Li-Ion battery production estimates that "on average, producing 1 Wh of storage capacity is associated with a cumulative energy demand of 328 Wh and causes greenhouse gas (GHG) emissions of 110 g $CO_{2\ eq}$" (ref 27).

The LIB cathode material NMC contains toxic cobalt and nickel oxides. About 60% of the global production of cobalt comes from Congo and the environmental health risks and work conditions in relation to the cobalt mining rises ethical concerns (ref 28). Visual capitalist believes the cobalt content in NMC could decrease to 10% already in 2020 (ref 29).

Starting about two years ago, fears of a lithium shortage almost tripled prices for the metal (ref. 30). Demand for lithium won't slacken anytime soon - according to Bloomberg New Energy Finance the electric car production alone is expected to increase more than thirtyfold by 2030. However, the next dozen years will drain less than 1 percent of the reserves in the ground, BNEF says. But battery makers are going to rapidly increase mining capacity to meet the demand.

Research and development perspectives

Currently, a wide range of government and industry-sponsored LIB material, cell and system level research is taking place. Some of the ongoing material research to further increase the energy density of LIB cells includes high-voltage electrolytes allowing charging voltages of up to 5 volts and silicon nanoparticle based anodes to boost the charge capacity. Several research and development activities focus on improving the cycle lifetime of LMO cells (ref. 31 to 35).

Some of the most promising post Li-ion technologies include Lithium Sulphur batteries that use Sulphur as an active material. Sulphur is abundantly available at reasonable price and allows for very high energy densities of up to 400 Wh/kg. Also, Lithium air batteries have received considerable attention. Since one of the active materials, oxygen, can be drawn from the ambient air, the lithium-air battery features the highest potential energy and power density of all battery storage systems. Due to the existing challenges with electrode passivation and low tolerance to humidity, large-scale commercialization of the lithium-air battery is not expected within the next years.

Several non-lithium-based battery chemistries are being investigated. Aluminum Sulphur batteries may reach up to 1000 Wh/kg with relatively abundant electrode materials but are still in the very early development phase (ref. 36).

Besides the materials research, improved cell design, BMS, TMS and EMS technology and operation strategy can improve storage efficiency considerably (ref. 17. Although LIB systems for electricity storage are now commercially available, the R&D is still in its relatively early phase and is expected to contribute to future cost reductions and efficiency improvements.

Examples of market standard technology

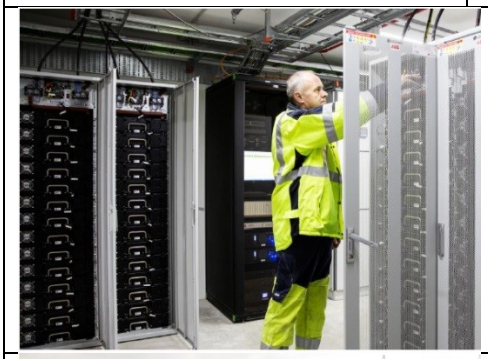
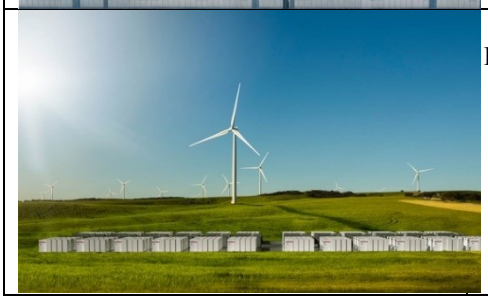
Grid scale turn-key LIB systems are commercially available from a wide range of suppliers. Two larger grid-connected LIB systems are installed in Denmark: **A)** In Copenhagen, Denmark a 630 kW/460 kWh was installed by ABB in 2017. This set the scene for Ørsted first steps into commercial battery storage. For Ørsted the following energy storage projects are under development: a 20 MW battery storage near Liverpool in UK, a 1 MW storage pilot project in Taiwan and a 55 MW battery storage for the Bay State Wind project in USA (ref. 37). **B)** Lem Kær Wind Farm was Vestas pilot project for energy storage. Vestas is working on Kennedy Power Plant that integrates wind and solar with grid-scale energy storage

and will feature a 2 MW / 4 MWh grid-scale LIB storage system to providing flexibility and increasing the energy production.

Globally the two largest grid-scale LIB storage system is the Mira Loma Substation in California which features 20MW/80MWh using 400 Tesla Powerpack 2 (ref. 38 and 39). and the Neoen's Hornsdale Wind Farm which feature a 100MW/129MWh (ref. 40), both systems providing peak shaving.

The Laurel Mountain, West Virginia, USA grid-scale LIB storage system a 32MW/8MWh (ref. 41) are designed for frequency regulation and with high power to energy ratio compared to the Tesla grid-scale LIB storage system which are designed for peak shaving with a low power to energy ratio.

Table 22: Example of market standard technology for grid-connected LIB systems.

Image	Location	Primary usage	Year	Power capacity	Techn. provider	Ref.
	Energylab Nordhavn, Copenhagen, Denmark	Frequency Regulation Peak Shaving Voltage Regulation Harmonic Filtering	2017	630 kW 460 kWh NMC	ABB for Radius Elnet / Ørsted	42
	Lem Kær Wind Farm, Denmark	Frequency regulation	2014	400kW LFP and 1.2MW LTO	Altairnano and A123 for Vestas	43
	Mira Loma Substation, California, USA	Peak Shaving	2016	20 MW 80 MWh	Tesla	38, 39
	Neoen's Hornsdale Wind Farm, South Australia	Peak Shaving	2017	100 MW 129 MWh	Tesla	40

	Laurel Mountain, Belington, West Virginia, USA	Frequency Regulation and Renewable Energy Integration	2011	32 MW 8 MWh	AES and A123	41

Prediction of performance and cost

The recent industry average LIB pack cost forecast taken from Bloomberg's New Energy Outlook 2018 is shown in the figure below (ref. 41). The current LIB price is close to 200$/kWh and the forecast (dotted line) predicts a battery price of 70 $/kWh by 2030. Further, the forecasted added installed capacity between now and 2050 is estimated to 1291 GW (ref. 44). Using Bloombergs 18% learning rate and the predicted capacity growth, this results in a forecasted 50$/kWh in 2040 and 40 $/kWh in 2050.

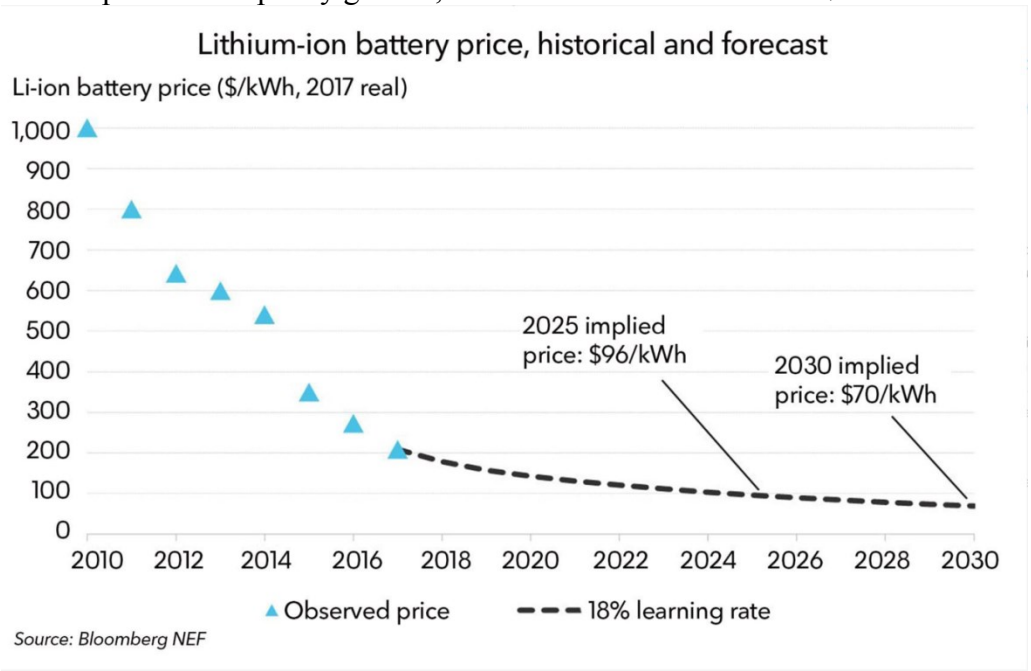


Figure 45: Historical and forecasted Lithium-ion battery pack cost (ref. 44).

TESLA through its Gigafactory is reported to be 4-5 years ahead of the industry average with a pack cost level of US$190/kWh already in 2016 and indications have been reported of US$ 100/kWh before 2020 (ref. 45) and US$ 80/kWh soon thereafter (ref. 46).

The cost reductions are backed up by a rapid increase in the LIB production capacity. The production capacity is expected to grow from 28 GWh in 2016 to 174 GWh by 2020 representing an impressive five-fold growth in four years (ref. 47).

The forecasted decrease in battery pack cost and increase in production capacity aligns with a forecasted steep growth rate of the utility-scale application market as shown in figures below The installed capacity is estimated to reach 14 GW in 2023 (ref. 48). Globaldata predicts this capacity level could be reached already in 2020 (ref. 49).

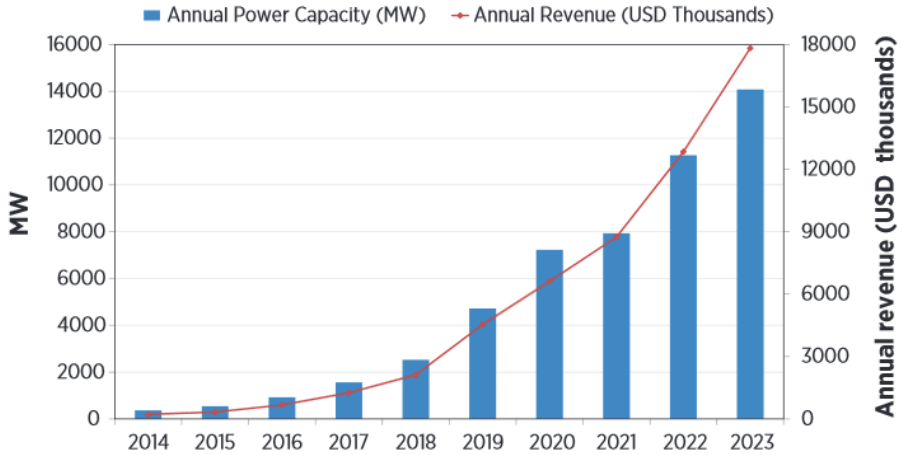


Figure 46: Worldwide forecast of battery storage capacity (MW) and annual revenue ($) for utility-scale applications (ref. 48).

Data sheet

The data sheet table summarizes the development predictions.

Technology		Lithium-ion battery							
	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Energy storage capacity for one unit (MWh)	6	7	8	5	9	7	12	A	2;14
Output capacity for one unit (MW)	18	21	24	16	21	22	28	A,B	2;14
Input capacity for one unit (MW)	3	3,5	4	2,7	3,5	3,7	4,7	A,B	2;14
Round trip efficiency (%) AC	91	92	92	90	92	91	94	C	3;21;22;51
Round trip efficiency (%) DC	95	96	96	95	96	95	97	C	3;21;22;51
- Charge efficiency (%)	98	98,5	98,5	98	98,5	98	99	D	2
- Discharge efficiency (%)	97	97,5	97,5	97	98	97	98	D	2
Energy losses during storage (%/day)	0,1	0,1	0,1	0,05	0,2	0,05	0,15	E	18;50;52
Forced outage (%)	0,38	0,35	0,25	0,2	0,5	0,1	0,3	F	0
Planned outage (weeks per year)	0,2	0,1	0,1	0,1	0,25	0,05	0,2	F	0
Technical lifetime (years)	20	25	30	15	25	20	45	G	3;5;8;14
Construction time (years)	0,2	0,2	0,2	0,2	0,25	0,1	0,25	0	38
Regulation ability									
Response time from idle to full-rated discharge (sec)	<0.08	<0.08	<0.08	<0.08	<0.08	<0.08	<0.08	H	53
Response time from full-rated charge to full-rated discharge (sec)	<0.08	<0.08	<0.08	<0.08	<0.08	<0.08	<0.08	H	53
Financial data									
Specific investment (M$ per MWh)	0,49	0,34	0,15	0,36	0,63	0,07	0,34	I	44;48
- energy component (M$/MWh)	0,15	0,07	0,04	0,08	0,21	0,03	0,13	J	44
- capacity component (M$/MW) PCS	0,31	0,18	0,07	0,27	0,58	0,05	0,28	K	54–56
- other project costs (M$/MWh)	0,11	0,09	0,05	0,10	0,12	0,02	0,12	L	22;40;54
Fixed O&M (k$/MW/year)	0,61	0,61	0,61	0,51	0,61	0,45	0,61	M	22
Variable O&M ($/MW/year)	2,3	2,0	1,8	0,5	6,3	0,3	2,8	N	55
Technology specific data									
Energy storage expansion cost (M$/MWh)	0,26	0,16	0,08	0,18	0,29	0,05	0,20	O	44;48
Output capacity expansion cost (M$/MW)	0,31	0,18	0,07	0,27	0,58	0,05	0,28	P	54–56
Alternative Investment cost (M$/MW)	0,37	0,23	0,09	0,32	0,66	0,06	0,35	Q	41;44;48;54–56
Lifetime in total number of cycles	14.000	30.000	50.000	10.000	16.000	20.000	70.000	R	3–5;14
Specific power (W/kg)	700	900	1.200	600	900	1.000	2.000	S	2;24
Power density (kW/m3)	800	1.000	1.400	750	900	1.200	2.000	S	2;24
Specific energy (Wh/kg)	105	139	209	100	140	150	300	S	2;24
Energy density (kWh/m3)	130	173	260	150	200	200	400	S	2;24

Notes:

A. One unit defined as a 40 feet container including LIB system and excluding power conversion system. Values for 2015-2030 are taken from Samsung SDI brochures for grid-connected LIBs from 2016 and 2018 [2,14].
B. Power output are set to 3 times the energy capacity as it is the standard grid-connected LIBs designed for power purposes [2,14].
C. The average DC roundtrip efficiency is expected to increase slightly as the storage cost in $/kWh decreases since this promotes operation at lower C-rates. 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. The C-rate is 0.5 during charge and up to 6 during discharge for the Samsung SDI batteries [2]. The presented conversion efficiencies assume average discharge C-rates in 2015-2020 around 2.5 and charge C-rates around 0.5.
E. Lithium-ion battery daily discharge loss. The central estimates for self-discharge of Li-ion batteries range between 0.05% and 0.20% a day in 2016 and are expected to stay flat to 2030.
F. 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.
G. Current state-of-the-art NMC LIB has 20 years lifetime. The NMC lifetime is expected to reach LTO lifetime by 2020 and 30 years lifetime for grid-connected LIBs in 2040 and 2050 as photovoltaic power systems have today [3,5,8,14].
H. The response time is obtained from simulated response time experiments with hardware in the loop [53].
I. The forecast of the system specific investment cost is estimated as 2.5 times the battery forecast. The forecast is exclusive power cables to the site and entrepreneur work for installation of the containers [44,48].
J. The battery pack cost forecast is provided in Figure 8 and the related text [44].
K. Power conversion cost is strongly dependent on scalability and application. The PCS cost is based on references [54–56] and reflects the necessity for high power performance and compliance to grid codes to provide ancillary services, bidirectional electricity flow and two-stage conversion, as well as the early stage of development and the fact that few manufacturers can guarantee turnkey systems.
L. Other costs include construction costs and entrepreneur work. These costs heavily dependent on location, substrate and site access. Estimates are aggregated from the literature [22,40,54]
M. Inverter replacement is expected every 10 years [22].
N. No variable O&M is assumed since the LIB storage system is stand-alone.
O. Since multi-MWh LIB systems are scalar, the energy storage expansion cost equals the Specific investment cost [44,48].
P. Since multi-MW LIB systems are scalar, the capacity expansion cost equals the capacity component cost [54–56].
Q. The alternative investment cost in M€2015/MW is specified for a 4C, 0.25 h system as for the Laurel Mountain, West Virginia, USA grid-scale LIB storage system [41]. I.e. the alternative investment cost is 25% of the energy storage expansion cost plus the PCS cost [41,44,48,54–56].
R. 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].
S. Specific power, power density, Specific energy and energy density is provided for discharge mode, starting with the values provided in the section "Typical characteristics and capacities". A charge/discharge conversion factor of 12 can be derived from this section. The expected development depends on the successive R&D progress as indicated in the section "Research and development perspectives" [2,24].

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APPENDIX 1: 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 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 just below 70%).

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 concisely as possible. The following paragraphs are included if found relevant for the technology.

Technology description
Brief description for non-engineers 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. If relevant, other output such as process heat are mentioned here.

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

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.

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.

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

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 is 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 is 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).

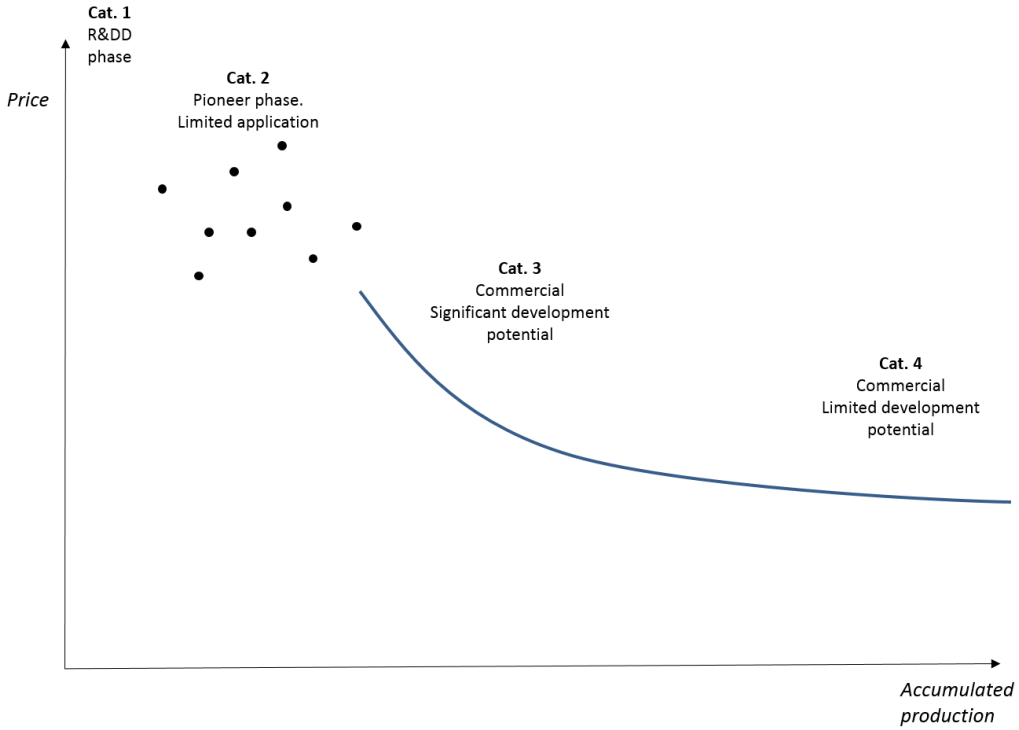

Figure 47: Technological development phases. Correlation between accumulated production volume (MW) and price.

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

Quantitative description

To enable comparative analyses between different technologies it is imperative that data is 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 Vietnamese society. In this context taxes do not represent an actual cost but rather a transfer of capital between Vietnamese 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 ($), price year 2016. When converting costs from a year X to $2016 the following approach is recommended:

1. If the cost is stated in VDN, convert to $ using the exchange rate for year X (first table below).
2. Then convert from $ in year X to $ in 2016 using the relationship between the US Producer Price Index for "Engine, Turbine, and Power Transmission Equipment Manufacturing" of year X and 2016 (second table below).

Table 23: The yearly average exchange rate between VND and $.

Year	VND to $
2007	16,069
2008	16,842
2009	17,773
2010	19,080
2011	20,585
2012	20,905
2013	21,205
2014	21,330
2015	21,840
2016	22,322
2017	22,725
2018	22,960

Table 24: US Producer Price Index for "Engine, Turbine, and Power Transmission Equipment Manufacturing". US Bureau of Labor Statistics, Series Id: PCU333611333611). www.bls.gov
2018 value has data including November. August to November is preliminary.

Year	Producer Price Index
2007	169.0
2008	188.6
2009	209.9
2010	210.4
2011	212.5
2012	211.1
2013	215.0
2014	220.6
2015	221.1
2016	220,7
2017	213.5
2018	(210.4)

The construction time, which is also specified in the data sheet, represents the time between the financial closure,

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

Before using the data, please note that essential information may be found in the notes below the table.

Energy/technical data

The data tables hold information about 2020, 2030 and 2050. The year is the first year of operation.

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. The sizes of units and the total power plant should 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 delivered to the grid.

The unit MW is used for electric generation capacity, 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 Vietnam, 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 operation 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. 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 8,760 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:

- Ramping (% per minute) i.e. the ability to ramp up and down when the technology is already in operation.
- Minimum load (per cent of full load): The minimum load from which the boiler can operate
- Warm start up time, (hours): The warm start-up time, used for boiler technologies, is defined as the time for starting, from a starting point where the water temperature in the evaporator is above 100°C, which means that the boiler is pressurized.
- Cold, start-up time, (hours). The cold start-up time used for boiler technologies is defined as the time it takes to reach operating temperature and pressure and start production from a state were the boiler is at ambient temperature and pressure.

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

on/off-mode.

Environment

The plants should be designed to comply with the regulation that is currently in place in Vietnam and planned to be implemented within the 2020-time horizon.

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

Emissions of particulate matter are expressed as $PM_{2.5}$ in gram per 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 difference 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 represent emissions of NO_2 and NO, where NO is converted to NO_2 in weight-equivalents. NO_x emissions are also stated in grams per GJ fuel.

Emissions of methane (CH_4) and Nitrous oxide (N_2O), are not included in the catalogue. However, these are both potent greenhouse gas, and for certain technologies, for example for gas turbines, the emissions can be relevant to include. In further development of the catalogue these emissions could also be included.

Financial data

Financial data are all in $ fixed prices, price-level 2016 and exclude value added taxes (VAT) or other taxes.

For projection of future financial costs there are three overall approaches; Engineering bottom-up, Delphi-survey, and Learning curves. This catalogue uses the learning curve approach. The reason is, that this method has proved historically robust and that it is possible to estimate learning rates for most technologies. Please refer to appendix 2 in the Indonesian TC for a separate note, “Forecasting cost of electricity production technologies”, on the approach used in this catalogue.

Investment costs

The investment cost or initial cost is often 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, the intention is that investment cost 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, do 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 costs of grid connection is included, however possible costs of grid expansion from adding a new electricity generator to the grid are not included in the presented data.

Business cycles
Costs of energy equipment surged dramatically in 2007-2008. The trend was general and global. One example is combined cycle gas turbines (CCGT): "*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.*" (Global CCS Institute). Such unprecedented variations obviously make it difficult to benchmark data from the recent years, but a catalogue as the present cannot be produced without using a number of different sources from different years. 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 are usually less than that of smaller plants. This is called the 'economy of scale'. The proportionality was examined in some detail in the article "Economy of Scale in Power Plants" in the August 1977 issue of Power Engineering Magazine (p. 51). The basic equation 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-scale plants, like large coal power plants, we may have reached a practical limit, since very few investors are willing to add increments of 1000 MW or above. Instead, by building multiple units at the same spot can provide sufficient savings through allowing sharing of 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 are 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 and insurance. Any necessary reinvestments to keep the plant operating within the technical lifetime are also included, whereas reinvestments to extend the life beyond the technical life time 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.

O&M costs often develop over time. The stated O&M costs are therefore average costs during the entire lifetime.

Uncertainty
The *uncertainty* indicated in the data tables 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.

References
IEA, 2016, Energy Technology Perspectives 2016. IEA/OECD.

Edward S. Rubin, Inês M.L. Azevedo, Paulina Jaramillo, Sonia Yeh. Review article. A review of learning rates for electricity supply technologies. Elsevier 2015.