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Viet Nam Technology Catalogue for Power Generation and Storage

Background report to Viet Nam Energy Outlook Report 2021

2021

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FOREWORD

Today, innovations and technology improvements within energy generation and storage are taking place at a very rapid pace, making long-term energy planning a central key to unlocking the potential of the new, green technologies. The long-term planning of energy systems is very dependent on cost and performance of future energy producing technologies. Thus, 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 providing a key input to solid long-term 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 Electricity and Renewable Energy Authority (EREA) and agencies under 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 long-term energy/power modelling in Vietnam and support government institutions, private energy companies, think tanks and others through a common and broadly recognized set of data for future electricity producing technologies in Vietnam.

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

Context

This publication is developed under the Danish-Vietnamese Energy Partnership. The first Viet Nam Technology Catalogue was published in 2019. This new version includes all the technologies from the 2019 version that have been reviewed and updated where necessary. A main focus of the update has been to add new subcategories of technologies (roof-top solar PV, floating offshore wind, low wind speed turbines, improved flexibility of coal fired plants and pollution prevention technologies for coal power) as well as completely new technology descriptions and data sheets (tidal power, wave power, carbon capture and storage, coal CFB boilers and industrial cogeneration).

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INTRODUCTION

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 and 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 on research and development indicating their technological progress, their future development perspectives and the uncertainty related to the projection of cost and performance data.

The technologies in the catalogue includes the power production unit and the connection to the grid. This means that 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 text and data have been edited based on Vietnamese cases to represent local conditions. For the mid- and long-term future (2030 and 2050) international references have been relied upon for most technologies since Vietnamese data is 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 the 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, or domestic coal quality can affect efficiency and variable cost of coal-fired plants as well.

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.

1. PULVERIZED COAL FIRED POWER

Brief technology description

In a coal fired power plant, pulverized coal is burned to generate steam used to generate electricity. Coal-fired plants run on a steam-based Rankine cycle. In the first step the operating fluid (water) is compressed to high pressure using a pump. In the next step, the boiler heats the compressed fluid to its boiling point converting it to steam, still at a high pressure. In the third step the steam is allowed to expand in the turbine, thus rotating it. This in turn rotates the generator and mechanical energy is converted to electromagnetic energy which is then converted to electrical energy and electricity is produced. The final step in the cycle involves condensation of the steam in the condenser. See Figure 1 below.

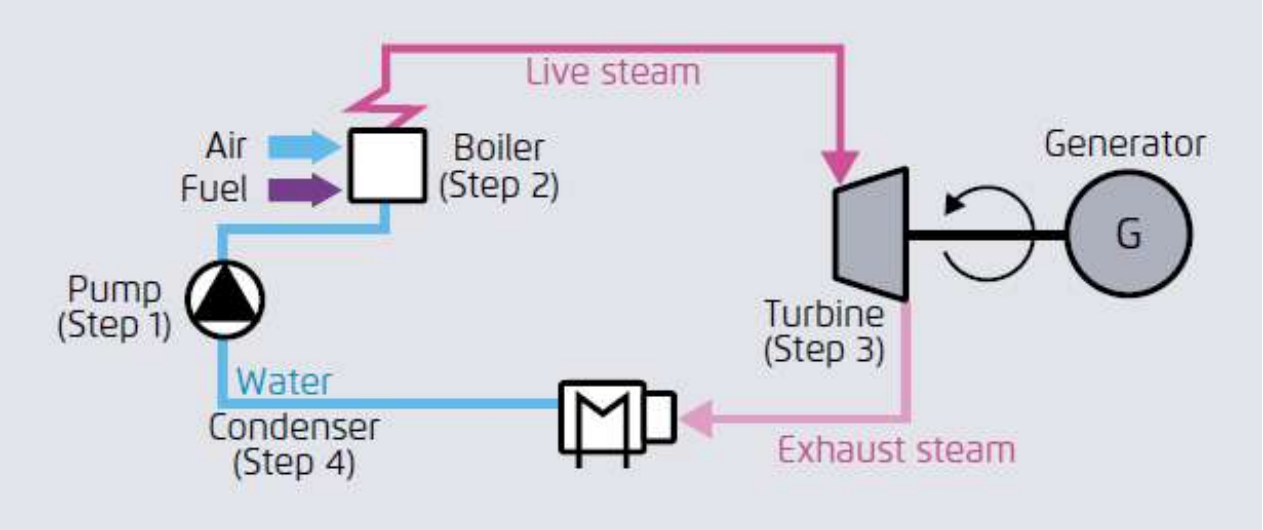


Figure 1: Schematic representation of operational flow of steam-based Rankine cycle in coal plants (ref. 3).

Generally, one distinguishes between three main types of coal fired power plants: subcritical, supercritical and ultra-supercritical. Besides these three, there is also advanced ultra-supercritical coal fired power plants. 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 Fig. 2. In Vietnam, a number of subcritical plants are operating but this catalogue focuses on supercritical and ultra-supercritical as no new subcritical plants are planned in Vietnam in the future in according to the orientation indicated in Power Master Plan VIII (chapter IV).

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). This is shown in Figure 2 below. Advanced ultra-supercritical power plants operate at 700-725°C and at 250-350 bars. Advanced ultra-supercritical power plants need more advanced materials (ref. 16).

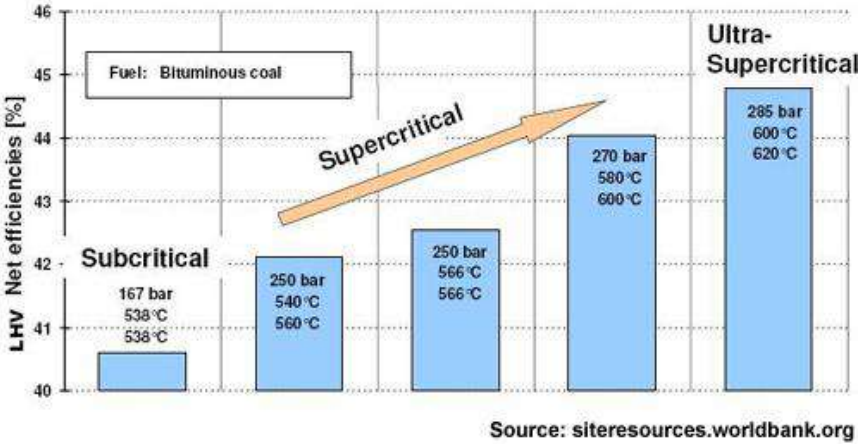


Figure 2: Definitions of sub-, super-, and ultra-supercritical plant (ref. 6).

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.

Coal fired power plants typically use pulverized coal. Coal is pulverized into small pieces such that the surface area is increased, and it burns more easily. Existing coal fired plants could potentially be converted to use natural gas or LNG. Natural gas or LNG could improve flexibility of the plant, lower CO2 emissions and potentially reduce costs. For instance, in the US, more than 2 percent of the existing coal fired power plant have been converted from coal to natural gas since 2010.

The extent of the conversion of the plant depends primarily on the design of the boiler. Moreover, the environmental legislation could also cause more significant design changes in order to meet needed emissions requirements.

In some cases, the coal burner can simply be modified to use natural gas instead while in other cases, the coal burner needs to be completely replaced. This depends on the age of the equipment and the environmental requirements. Conversion of fuels can be associated with a loss of efficiency since the heat transfer with the new or modified burning of fuel varies from what the boiler was originally designed for. The impact depends on the physical geometry of the boiler, materials of construction, remaining component life, desired operating capacity and how sensitive the steam turbine-generator set is to changes in temperature. Moreover, the moisture content of natural gas could also impact the heat transfer. (ref. 15)

Output

Power. The auxiliary power need for a 500 MW plant is typically 40-45 MW, and the net electricity efficiency[1] 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- 9 percent.

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 primary load support (frequency control) and secondary load support. Advanced units are in general able to deliver 1.5÷5 percent of their rated (maximum) capacity as frequency control within 30 seconds at loads between 50 and 90 percent.

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 percent 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.

[1] For a power plant, the gross efficiency is defined as the electric capacity divided by the fuel consumption while the net efficiency is defined by the electric capacity minus the auxiliary power need divided by the fuel consumption. See Appendix 1 for definitions of efficiencies.

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.

Typical Danish coal-based power plants have minimum generation of 15-30 percent and ramping speeds of roughly 4 percent 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. (Ref. 5 and ref. 6).

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

<table>
<tr><th>General operational flexibility improvements</th><th colspan="2">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="3">Lower minimum load</td></tr>
<tr><td colspan="3">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="3">Improving ramping speed and fast output regulation</td></tr>
<tr><td colspan="3">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. According to several studies including Bascom et al., 1996 and Kelsall et al., 1997 (see ref. 14 for a more comprehensive review) air pollution from coal fired power plants is responsible for thousands of premature deaths each year globally.
- Coal firing results in a relatively high CO_2 emission
- 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.
- Using water from rivers or seas for cooling can change the local aquatic environment.

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. Technologies and costs for reducing pollution is described a section below ("Technologies to reduce pollution").

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 needs 2,000-2,500 employees on average during construction and afterwards 600-900 employees continuously for operation and maintenance (not including coal mining workers).

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 per year (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 a 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 do not exceed 400 and 150 mg/Nm^3 respectively. According to actual measurement, the NO_x, SO_2 and $PM_{2.5}$ emission of Quang Ninh thermal plant are 700 mg/Nm^3, 394 mg/Nm^3 and136 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 1.47 billion $ (converted to $2019, the administration, consultancy, project management, site preparation cost, the taxes and interest during construction are not included) equal to a nominal investment of 1.22 M/MW_e$. The total capital cost (including these components) was 1.61 billion $, corresponding to 1.34 M/MW_e$. The fixed O&M cost is 41.55 $\$/kW_e$/year and the variable O&M cost is 1.06 $/MWh.

Subcritical Hai Phong coal-fired power plant: (ref 10)

Hai Phong coal-fired plant located in Thuy Nguyen district, Hai Phong city with a total capacity of 1,200 MW,

including 4 units of 300 MW. Hai Phong 1 plant (2x300 MW) started operation in 2009/2010, Hai Phong 2 plant (2x300 MW) started operation in 2013/2014. The plant uses pulverized coal combustion with a sub-critical boiler (superheated parameter of 175 kg/cm^3 and 541^{0}C). The self-consumption rate of the 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 the 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 1.37 billion $ (converted to $2019, the administration, consultancy, project management, site preparation cost, the taxes and interest during construction are not included), equal the nominal investment was 1.14 M$/ MW_e. The total capital cost (including these components) was 1.59 billion $, corresponding to 1.32 M$/MW. The fixed O&M cost was 47.3 $/ kW_e/year and the variable O&M cost is 1.14 $/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. The construction started in March 2014, and the first unit was completed and came into commercial operation in December 2017 and the second one in March 2018.

Vinh Tan 4 thermal plant combusts pulverised coal and was the first Vietnamese coal-fired power plant applying a super-critical (SC), including redrying, with the main steam parameter: steam capacity of 1,730.3 t/h; main steam pressure of 251.04 bar; superheated steam temperature of 569.8 $^\circ$C; redrying steam temperature of 594.4 $^\circ$C. The net electricity efficiency of the plant (name plate) is 39.8% (LHV). The main fuel of Vinh Tan 4 thermal plant is Sub-Bitumen (70%) and Bitumen (30%) imported from Indonesia and Australia. Fuel consumption is approximately 3.36 million tons per year. Diesel oil is used as auxiliary fuel for starting the furnace and burning in low load. Following the automatic monitoring data of the first 6 months in 2020, the NO_x emission value is 249 mg per Nm^3, the SO_2 is 181 mg per Nm^3 and the $PM_{2.5}$ emission is 27 mg per Nm^3. However, performance test of the operation is not representative for the emission levels. Operating characteristics of Vinh Tan 4 thermal plant are: Ramping 2÷3% per minute, minimum load is 40% of full load (minimum level without burning oil), warm start-up time and cold start-up time are ≤ 6.33 hours and ≤ 9.17 hours, respectively.

The total investment of Vinh Tan 4 thermal plant was 1.66 billion $ (converted to $2019, the administration, consultancy, project management, site preparation cost, the taxes and interest during construction are not included), corresponding to a nominal investment of 1.38 M$/$MW_e$. The total capital cost (including these components) was 1.79 billion $, corresponding to 1.49 M$/MW. The fixed O&M cost was 39.47 $/$kW_e$/year and the variable O&M cost was 1.01 $/MWh.

Updated project: Super-critical: Vinh Tan 4 Extend (ref. 12)
Vinh Tan 4 Ext coal-fired power plant is in the Vinh Tan Power Center, in the Tuy Phong district, Binh Thuan province. The plant includes 1 unit of 600 MW and started construction in April 2016 and completed and came into commercial operation in October 2019.

Vinh Tan 4 Ext thermal plant uses pulverised coal combustion technology with a super-critical boiler. Main steam parameters are as follow: Main steam pressure is 251,0 bar; superheated steam temperature is 569.8^{0}C, redrying steam temperature is 594.4^{0}C. The net electricity efficiency of the plant (name plate) is 39.8% (LHV).
The main fuel of Vinh Tan 4 Ext thermal plant is Sub-Bitumen (70%) and Bitumen (30%) imported from Indonesia and Australia. Fuel consumption is approximately 1.68 million tons per year according to the designed capacity. Diesel oil is used as auxiliary fuel for starting the furnace and burning in low load. Following the automatic monitoring data of the first 6 months of 2020, the NO_x emission value is 103 mg per Nm^3, the SO_2 is 93 mg per Nm^3 and the $PM_{2.5}$ emission is 11 mg per Nm^3.

The total investment of Vinh Tan 4 thermal plant was 921 million $ (converted to $2019, the administration, consultancy, project management, site preparation cost, the taxes and interest during construction are not included), corresponding to a nominal investment of 1.54 M$/$MW_e$. The total capital cost (including these components) was 1035 million $, corresponding to 1.73 M$/MW.

Updated project: Super-critical: Vinh Tan 1 (ref. 11)
General: Vinh Tan I coal-fired power plant is in the Vinh Tan Power Center, in the Tuy Phong district, Binh Thuan province. The installed capacity of the plant is 1200 MW, including 2 units of 600 MW. Construction was started in July 2015 and it was in commercial operation from November 2018.

Vinh Tan 1 thermal plant combusts pulverised coal and applies a super-critical boiler, with superheated steam parameters: pressure of 24.2 MPa (~ 242 bar) and temperature of 566°C. The net electricity efficiency of the plant (name plate) is 39.2% (LHV). Vinh Tan 1 is the first coal-fired thermal power plant in Vietnam to apply the supercritical W-shaped flame boiler technology, using domestic Anthracite coal. Diesel oil is used as auxiliary fuel for starting the furnace and burning in low load. According to data provided from power plant, the NO_x emission value is 235 mg per Nm^3, the SO_2 is 29 mg per Nm^3 and the $PM_{2.5}$ emission is 21 mg per Nm^3. Operating characteristics of Vinh Tan 1 thermal plant are: Ramping 1% per minute, minimum load is 60% of full load (minimum level without burning oil), warm start-up time and cold start-up time are 2.25 hours and 12.75 hours respectively.

The total investment of Vinh Tan 1 thermal plant was 1.88 billion $ (converted to $2019, the administration, consultancy, project management, site preparation cost, the taxes and interest during construction are not included), corresponding to a nominal investment of 1.52 M$/$MW_e$. The total capital cost (include these components) was 2.03 billion $, corresponding to 1.66 M$/MW. The fixed O&M cost was 35 $/$kW_e$/year and the variable O&M cost was 1.20 $/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.

To estimate a central case for 2020, data from four Vietnamese supercritical plants have been collected. However, for some cases only selected data has been available. Therefore, data from the Indonesian TC has given further inputs to make a more realistic estimate. Several reports indicate that the lower minimum generation and higher ramp rates can be achieved without additional large investments. In the TC current minimum loads and ramp rates are assumed in 2020 whereas 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. See Table 2.

Table 2: Coal super-critical plant. 2020 data. ($2019) (Ref. 17)

Key parameter	Local case 1: Vinh Tan 4[2]	Local case 2: Vinh Tan 4 Ext	Local case 3: Vinh Tan 1	Local case 4: Duyen Hai 3 Ext	Indonesian TC (2020)	Vietnamese TC (2021)
					Central	
Generating capacity for one unit (MW_e)	600	600	620	688	600	600
Generating capacity for total power plant (MW_e)	1,200	600	1240	688	600	1,200
Electricity efficiency, net (%), name plate	39.8	39.8	39.2	39.5	38	38
Electricity efficiency, net (%), annual average	37	37	36.5	36.7	37	37
Ramping (% per minute)	2÷3	2÷3	1	-	4	2
Minimum load (% of full load)	40	40	60	-	30	50
Warm start-up time (hours)	≤6.33	≤6.33	2.25	-	4	6
Cold start-up time (hours)	≤9.17	≤9.17	12.75	-	12	10
Emission $PM_{2.5}$ (mg/Nm^3)	27	11	21	-	150	70
SO_2 (degree of desulphuring, %)	86[3]	91	97	-	73	86
NO_X (g per GJ fuel)	81	36	82	-	263	115
Nominal investment (M/MW_e$)	1.38	1.53	1.35	1.37	1.46	1.46
Fixed O&M ($/MW_e$/year)	39,500	-	36,400	-	42,800	39,600
Variable O&M ($/MWh)	1.01	-	1.20	-	0.12	0.78
Start-up costs ($/MW_e$/start-up)	260	-	256	-	52	187

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.

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

[3] 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 %.

Table 3: Investment costs in international studies, coal-based plants. All numbers are in unit M$$_{2019}$/MW$_e$

IEA WEO 2016[4]	**All year: 2015-2040**						
	China			India			
Super-critical	0.73			1.25			
Ultra-supercritical	0.83			1.46			
IEA Southeast Asia 2015	**Southeast Asia / 2030**						
Super-critical[5]	1.60						
Indonesian TC	**2020**			**2030**	**2050**		
	Central	Lower	Upper		Central	Lower	Upper
Super-critical (600 MW)[6]	1.46	1.09	1.82	1.41	1.37	1.03	1.72
Ultra-supercritical	1.58	1.19	1.99	1.54	1.49	1.11	1.86
Vietnamese TC	**2020**			**2030**	**2050**		
	Central	Lower	Upper		Central	Lower	Upper
Super-critical	1.43	0.73	1.82	1.45	1.42	0.73	1.72
Ultra-supercritical	1.57	0.83	1.99	1.55	1.54	0.83	1.86

Table 3 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 such that prices and plant sizes relate for better comparison with other coal technologies. For the calculations, a proportionality factor of 0.8 is used. The proportionality factor expresses the connection between costs and size. The method is further described in Annex 1.

There are large variations between the estimates. The estimates for Chinese plants in IEA WEO 2016 are very low which might be based on high volume production of coal-fired power plants. Furthermore, it is noted that IEA WEO 2016 assumes no reduction in investment costs from 2015 to 2040, while a small reduction is expected in the Indonesian TC. (Ref. 16).

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 cases are also included in the average (average of 1.2, 1.6, 1.4 and1.33) for 2020, (average of 1.2, 1.6 and 1.36) for 2030 and (average of 1.2, 1.6 and 1.32) for 2050).

For ultra-supercritical an average among the available data for the technology are also used, incl. the same exception for the estimates for China but with inclusion of IEA Southeast Asia super-critical plants. The reason for including IEA Southeast Asia super-critical plants in the average is that ultra-supercritical plants are expected to have at least as high investment costs as super-critical and including the number for Southeast Asia super-critical power plants increases the estimate (average of 1.4, 1.6 and 1.52) for 2020, (average of 1.4, 1.6 and 1.48) for 2030 and (average of 1.4, 1.6 and 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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2. DEA, "Technology data for energy plants – Generation of electricity and district heating, energy storage and energy carrier generation and conversion", 2018.
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[4] International Energy Agency, World Energy Outlook, 2016 (Ref. 16)

[5] Including interest during construction, engineering

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

6. Thermal Power Plant Flexibility, a publication under the Clean Energy. Ministerial campaign, 2018. http://www.ea-energianalyse.dk/reports/thermal_power_plant_flexibility_2018_19052018.pdf, Assessed 9 September 2018.
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8. Flexibility in thermal power plants. With a focus on existing coal-fired power plants. Angora Energiewende, Prognos and Fichtner, 2017.
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11. EVNPECC2, "Vinh Tan 4 coal-fired power plant- 1200 MW feasibility study report", 2013
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15. IEA Clean Coal Centre, "Status of advanced ultra-supercritical pulverised technology", 2013
16. International Energy Agency, World Energy Outlook, 2016
17. Technical, operational and cost data are collected from power plants, basic design/engineering design report, project website, power system dispatching agency. Emission data are taken from emission measurement reports, automatic monitoring data, and basic design/engineering design report.

Data sheets

The following tables contain the data sheets of the technology. All costs are stated in U.S. dollars ($), price year 2019. For explanation and definition of the parameters given in the table, see appendix 1. Uncertainty represents the variation in parameters.

Technology	**Supercritical coal power plant**								
$2019	**2020**	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data				**Lower**	**Upper**	**Lower**	**Upper**		
Generating capacity for one unit (MWe)	600	600	600	300	800	300	800		1
Generating capacity for total power plant (MWe)	1,200	1,200	1,200	300	1,800	300	1,800		1
Electricity efficiency. net (%). name plate	38	39	40	33	40	35	42		1;3;6;7
Electricity efficiency. net (%). annual average	37	38	39	33	40	35	42		1;3
Forced outage (%)	7	6	3	5	15	2	7	A	1
Planned outage (weeks per year)	7	5	3	3	8	2	4	A	1
Technical lifetime (years)	30	30	30	25	40	25	40		1
Construction time (years)	4	3	3	3	5	2	4	A	1
Space requirement (1000 m^2/MWe)	-	-	-	-	-	-	-		
Additional data for non-thermal plants									
Capacity factor (%). theoretical	-	-	-	-	-	-	-		
Capacity factor (%). incl, outages	-	-	-	-	-	-	-		
Ramping configuration									
Ramping (% per minute)	2	4	4	1	4	3	4	B	1
Minimum load (% of full load)	50	25	20	25	75	10	30	A	1
Warm start-up time (hours)	6	4	4	2	8.5	2	5	B	1
Cold start-up time (hours)	10	12	12	6	15	6	12	B	1
Environment									
PM 2,5 (mg per Nm^3)	70	70	70	50	150	20	100	E	2;4
SO_2 (degree of desulphuring. %)	86	86	95	73	95	73	95		2;4
NO_X (g per GJ fuel)	115	113	38	152	263	38	263	C	2;4
Financial data									
Nominal investment (M$/MWe)	1.46	1.45	1.42	0.73	1.82	0.73	1.71	D;F;G	1;3;6;7
- of which equipment (%)									
- of which installation (%)									
Fixed O&M ($/MWe/year)	39,600	38,500	37,200	32,100	53,500	30,100	50,300	F	1;3;6;7
Variable O&M ($/MWh)	0.78	0.12	0.12	0.09	1.01	0.09	0.15	F	1;3
Start-up costs ($/MWe/start-up)	187	52	52	42	104	42	104		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/Nm^3 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 cost include the engineering, procurement and construction (EPC) cost. See description under Methodology.

Technology	Ultra-supercritical coal power plant								
$2019	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	1,000	1,000	1,000	700	1,200	700	1,200		1
Generating capacity for total power plant (MWe)	1,000	1,000	1,000	700	1,200	700	1,200		1
Electricity efficiency. net (%). name plate	43	44	45	40	45	42	47		1;3;6;7
Electricity efficiency. net (%). annual average	42	43	44	40	45	42	47		1;3
Forced outage (%)	7	6	3	5	15	2	7	A	1
Planned outage (weeks per year)	7	5	3	3	8	2	4	A	1
Technical lifetime (years)	30	30	30	25	40	25	40		1
Construction time (years)	4	3	3	3	5	2	4	A	1
Space requirement (1000 m^2/MWe)	-	-	-	-	-	-	-		
Additional data for non-thermal plants									
Capacity factor (%). theoretical	-	-	-	-	-	-	-		
Capacity factor (%). incl, outages	-	-	-	-	-	-	-		
Ramping configuration									
Ramping (% per minute)	5	5	5	4	5	4	5	B	1
Minimum load (% of full load)	30	25	20	25	50	10	30	A	1
Warm start-up time (hours)	4	4	4	2	5	2	5	B	1
Cold start-up time (hours)	12	12	12	6	15	6	12	B	1
Environment									
PM 2,5 (mg per Nm^3)	70	70	70	50	150	20	100	E	2;4
SO_2 (degree of desulphuring. %)	86	86	95	73	95	73	95		2;4
NO_X (g per GJ fuel)	115	113	38	115	263	38	263	C	2;4
Financial data									
Nominal investment (M$/MWe)	1.63	1.61	1.60	0.86	2.06	0.86	1.94	D;F;G	1;3;6;7
- of which equipment (%)									
- of which installation (%)									
Fixed O&M ($/MWe/year)	61,100	59,400	57,500	46,000	76,500	43,100	71,800	F	1;3;6;7
Variable O&M ($/MWh)	0.12	0.12	0.11	0.09	0.15	0.08	0.14	F	1;3
Start-up costs ($/MWe/start-up)	54	54	54	43	108	43	108		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 cost include the engineering, procurement and construction (EPC) cost. See description under Methodology.

Flexibility of coal power plants

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

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

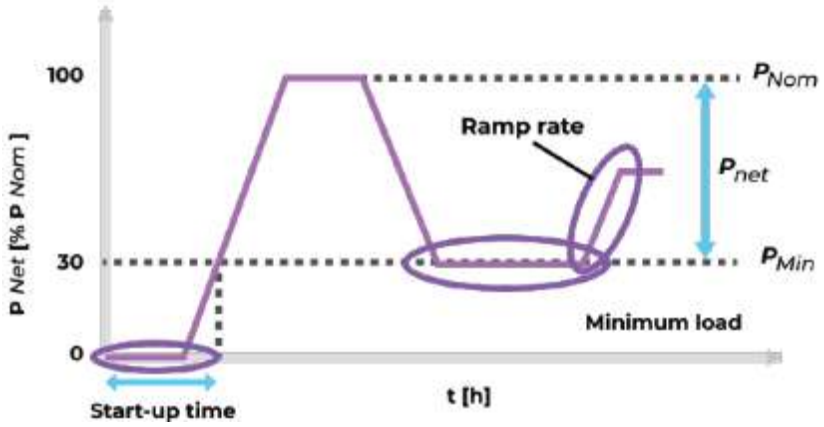


Figure 3: Key flexibility parameters of a power plant [3].

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

Table 4: Solutions for increasing the flexibility of coal-fired power plants [2], [4], [5].

Solutions	Objective	Description	Impact	Limitation
Indirect Firing	Lower minimum load, increased ramp rate and better part load efficiency	Milling is decoupled from load dynamics. Involves setting up a dust bunker between the coal mill and the burner to store pulverized coal. During periods of low load, auxiliary power can be used for coal milling, thereby reducing total power injected into the grid. Plus, this reduces the minimum load in high load periods as the required coal is already stored in the bunker and can be used flexibly.	Indirect firing can decrease the minimum stable firing rate. Firing rate and net power are proportional. A reduction of the firing rate therefore leads to a similar reduction of minimum load. Another advantage of reaching a low stable fire is that the need for ignition fuels, such as oil or gas, can be reduced by 95 %.	Fire stability

Switching from two-mill to single-mill operation	Lower minimum load	Switching to a single mill operation results in boiler operation with fewer burning stages. In this operation, heat is released only at the highest burner stage, ensuring operational stability.	Switching to a single mill operation has resulted in reducing minimum load to 12.5% P_{nom} in experiments conducted in hard coal-fired thermal plants at Bexbach and Heilbronn in Germany.	Water-steam circuit
Control system optimization and plant engineering upgrade	Lower minimum load, higher ramp rate, shorter start-up time	Upgrading control systems can improve plant reliability and help operate different components of the plant close to their design limits.	Control system and engineering upgrades resulted in the reduction of minimum load from nearly 67% P_{nom} to 48% P_{nom} at two units in the Weisweiler lignite-fired plant in Germany.	Fire stability/thermal stress
		Software systems that enable dynamic optimization of key components such as boilers can reduce the start-up time and increase ramp rate.	Boiler control system software have been developed that allow plant operators to choose between different start-up options based on market requirements.	
Auxiliary firing for stabilizing fire in boiler	Lower minimum load, higher ramp rate	This involves using auxiliary fuel such as heavy oil or gas to stabilize fire in the boiler. This ensures a lower stable firing rate in the boiler. Auxiliary firing can also be used for rapid increases to the firing rate, thereby enabling a higher ramp rate.	Since fire stability in the boiler usually limits the minimum load, auxiliary firing can support the minimum load reduction. As part of Jänschwalde research project, ignition burners were used for auxiliary firing using dried lignite, which reduced the minimum load from 36% P_{nom} to 26% P_{nom}.	Fire stability and boiler design
"New" turbine start	Shorter start-up time	This option involves starting up the steam turbine as the boiler ramps up by allowing "cold" steam to enter the turbine quickly after shutdown.	The start-up time can be reduced by 15 minutes using this approach.	Turbine design
Thin-walled components/special turbine design	Shorter start-up time, higher ramp rate	Using high-grade steel, thinner-walled components can be built to ensure quicker start-up and higher ramp rates compared to traditional thick-walled components.	Unknown	Mechanical and thermal stresses
Thermal energy storage for feed water preheating	Lower minimum load	Heat from the steam turbine can be absorbed by feed water, thereby reducing net power. Thermal energy stored in the feed water can be discharged to increase net power during periods of high demand.	Using a hot water storage system that can operate for 2–8 hours can reduce minimum load by 5–10%, and during discharge the hot water system can be used to increase net power by 5% without increasing the firing rate.	-

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

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

Table 5: Comparison of flexibility parameters before and after flexibilisation initiatives in a hard coal power plant [2], [4].

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

The estimation of cost for flexibility improvement solutions can vary on a case by case basis. A rough estimate suggests costs between 120,000 and 600,000 USD/MW [2], [4]. Furthermore, a study conducted by COWI and Ea Energy Analyses, investigated the cost of various flexibility improvements for coal plants. The investment cost estimates from this study are summarized below[7].

Table 6: Investment cost (in USD) estimated for specific flexibility improvement solutions based on a study for 600 MW hard coal power plant [6].

Solution	Investment estimate (in USD for a 600 MW hard coal power plant)
Lower minimum load *(from 40% to 25%)* (Includes: boiler circulation pump, connecting pipe work, control and stop valves, standby heating, electrical, instrumentation and programming of the DCS system)	1,898,101
Increased ramping speed *(from 1% to 2% per min.)* Upgrade of DCS-system Refurbishment of pulverizes	 156,314 424,281

Technologies to reduce pollution

Pollution from coal fired combustion can cause environmental problems including health problems for humans, deterioration of the atmospheric visibility, acid rain and more. Therefore, there is an increasing focus on limiting airborne pollution from the coal power plants. The most important emission control relates to NOx emissions, emissions of fine particles and sulphur emissions. Here follows a brief description on control measures for each of these.

NOx emission control

Nitrogen oxides (NOx) can cause a variety of environmental issues including ozone formation at ground level, acid rain, acidification of aquatic systems, forest damage, degradation of visibility, and formation of fine particles in the atmosphere. Therefore, there is a need to reduce the emissions of NOx.

During combustion, NOx is formed from three main chemical mechanisms:

1) "thermal" NOx resulting from oxidation of molecular nitrogen in the combustion air
2) "fuel" NOx resulting from oxidation of chemically bound nitrogen in the fuel

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

3) "prompt" NOx resulting from reaction between molecular nitrogen and hydrocarbon radicals. *(Ref. 1)*

For pulverized coal combustion, roughly 20% of NOx formation comes from thermal reactions. Thermal NOx formation could be lowered by reducing the oxygen concentrations in the furnace or by creating combustion zone temperatures and reducing the residence time of the flue gas in the high-temperature areas in the boiler.

Mechanisms for reducing the NOx emissions could include both mechanisms to reduce formation of NOx during the combustion process (so called primary control technologies) and mechanisms to convert NOx to less harmful compounds (so called secondary control technologies), for instance reducing NOx back to N_2.

Formation of NOx can in practice be reduced by

- increasing the size of the combustion zone for a given thermal input
- reducing the rate of combustion and, consequently, peak flame temperatures with specially designed burners *(ref.2)*

To obtain this, the following technologies could be applied *(ref. 2)*:

Low NOx burners (LNB)	A LNB limits NOx formation by controlling the stoichiometric and temperature profiles of the combustion process. This control is achieved by design features that regulate the aerodynamic distribution and mixing of the fuel and air, thereby yielding one or more of the following conditions: (1) reduced oxygen in the primary flame zone, which limits both thermal and fuel NOx formation; (2) reduced flame temperature, which limits thermal NOx formation; and (3) reduced residence time at peak temperature, which limits thermal NOx formation. LNBs can reduce NOx emissions by 50% or more at power plants without other control measures. With more facilitating design features, the reduction can be higher.
Overfire air (OFA)	OFA, also referred to as air staging, is a combustion control technology in which a fraction, 5–20%, of the total combustion air is diverted from the burners and injected through ports located downstream of the top burner level. OFA is used in conjunction with operating the burners at a lower-than-normal air-to-fuel ratio, which reduces NOx formation. OFA reduction rates range from 20% to >60% depending on the initial NOx levels of a boiler, fuel combustion equipment design, and fuel type. OFA can also be used in conjunction with LNBs. The addition of OFA to LNB on wall-fired boilers may increase the reductions by an additional 10 –25%

The reduction of NOx formation could in many cases not be enough to meet emission restriction from legal terms. (QCVN 22: 2009/BTNMT, QCVN 05:2013/BTNMT, QCVN 19: 2009/BTNMT). Moreover, for existing power plants it could be more relevant to look at post-combustion options where the boiler does not have to be changed significantly. Hence, technologies to reduce NOx in the flue gas by converting NOx have gained increased interest.

The three main technologies include:

1) Reburning
2) Selective noncatalytic reduction (SNCR) and
3) Selective catalytic reduction (SCR)

Reburning	Up to 25% of the heat can be reburned by injecting a secondary fuel above the main combustion zone. Here, a fuel rich reburn zone is created with a high amount of air. In the fuel rich zone hydrocarbons are formed that can react with NOx to form hydrogen cyanide (HCN), isocyanic acid (HNCO), isocyanate (NCO), and other nitrogen-containing species. These species are ultimately reduced to N2. The reburn technology has shown >50% NOx reduction on various coal-fired boiler types.
SNCR	SNCR is a proven, commercially available technology. In SNCR, ammonia (or urea) is injected into the furnace above the combustion zone. Ammonia reacts with NOx and reduces it to N_2. The reaction is very temperature dependent and the ammonia needs to be injected at the right zone in the furnace – typically at the top part of the furnace. The SNCR reaction works well at 980-1150 °C. At higher temperatures, another reaction will start to proceed where NOx is actually formed. Therefore, the optimal amount for ammonia added can be quite complex to estimate. The removal can be up to 65% of NOx.
SCR	In SCR, ammonia is also added and afterwards, the flue gas is passed through layers of catalyst. Ammonia and NOx react at the surface of the catalyst and NOx is reduced to N_2. SCR can remove up to 80%-90% of NOx and operates typically at low temperatures: 350-400 °C.

Particles
Combustion of coal leads to the emission of airborne particles matter (PM). Particles can cause severe deterioration of the atmospheric visibility and can harm human health when exposed to ambient PM, including respiratory problems and heart attacks. There is often a distinction between fine particles, $PM_{2,5}$, that is particles with an aerodynamic diameter less than or equal to 2.5 µm and coarse particles larger than that. Fine particles typically have a higher risk to cause health problems due to the fact that they can remain suspended for longer time periods and they can penetrate more deeply into the lungs after being inhaled, causing respiratory problems *(ref. 3).*

Ambient PM can be divided into primary and secondary PM. Primary PM are emitted from combustion, while secondary PM are formed in the atmosphere from gaseous emissions. Emissions from coal fired power plants are therefore primary PM and account for about half of the PM emissions. Several countries have adopted emission control legislation to limit the harmful effects of PM pollution. In the combustion process, PM are formed by a series of mechanisms. In the furnace where the temperature is high, all substances of the coal including the inorganic minerals start to vaporize. After the flame region, the vaporized minerals are cooled. In a supersaturated condition, minerals start to condensate and are made into particles of only a few nanometers, which can be further coagulated into larger ones. Later, particles are enlarged when other compounds condense on the surface of the particles. As such, fine PM enriched by numerous mineral elements are formed.

In order to avoid PM pollution, there are several measures to control the emission that can be taken. Here, it is possible to distinct between pre-combustion control measures and post-combustion control measures.

The precombustion control entails

- **Selection of coal type.** Coal can vary greatly in properties including pore sizes, constituents of inorganic minerals, the form of specific elements and more. Selecting coal based on the properties can therefore impact the formation of fine particles in the combustion process. The optimal type of coal depends on the combustion process. The general method to determine the applicable coal type is a coal combustion test on a specific furnace.
- **Coal preparation.** The size of the coal particles has great impact on the formation of PM. Less fine particles increase the number of fine particles formed during the combustion process. Preparing the coal to the right level of fineness can reduce the emission of PM.
- **Adjustments of the combustion conditions.** Combustion temperature, burning time, and boiler load all influence the formation of fine particles. Increasing combustion temperatures can lead to an increase in the volatilization of refractory minerals such as aluminium, iron and calcium. These minerals will typically be precipitated in the ashes, however under increased volatilization, these condense and coagulate and become fine PM. *(ref. 3).*

The post-combustion control measures can be retrofitted to existing coal fired power plants. The post-combustion control can reduce the PM emissions significantly. These can include:

- Electrostatic precipitators (ESPs)
- Baghouses or fabric filters
- Cyclones
- Wet scrubbers

Electrostatic precipitators and baghouse filters are the most dominant technologies and therefore only these are covered here.

Electrostatic precipitators:
An electrostatic precipitator is a type of filter or a dry scrubber that uses static electricity to remove particles from the flue gas. In the electrostatic precipitator, fine particles are agglomerated typically through three stages. First, coarse ash particles and fine particles are collected in submicrometer size, secondly the particles are agglomerated by adding a charged electrode with alternating or direct current voltage. Finally, the larger particles are collected. The electrostatic precipitator leaves clean, hot air to escape the smokestacks *[4].*

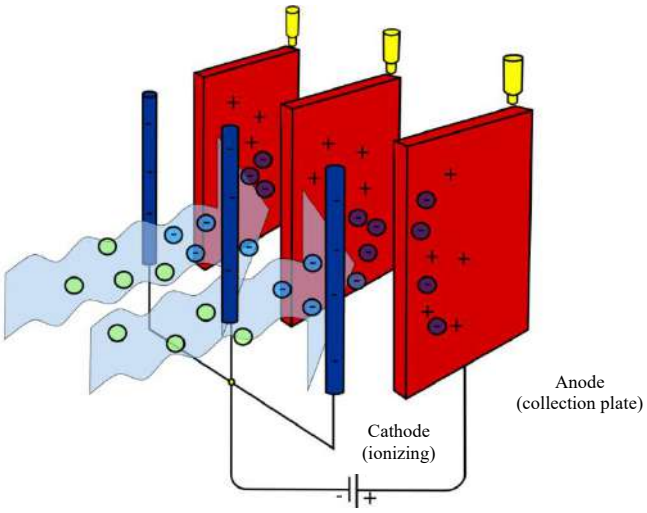


Figure 4: Principle behind electrostatic precipitator (ref.4).

Baghouse filters:
Fabric filters (called baghouse filters) is a very efficient way of removing suspended particles. Baghouse filters can remove almost 100 % of all particles of 1 µm or larger and a large share of smaller particles down to 0.01 µm. Baghouse filters typically consist of a long narrow bag about 25 cm in diameter suspended upside down. Fans blow the flue gas from combustion through the fabric from the bottom and the particles are then caught by the filter bag while the clean air passes through the filter. The drawback of using baghouse filters is that it implies relatively high airflow resistance which causes a significant energy consumption for the fans. Moreover, the baghouse filters need a cooled temperature of the airflow if the lifetime of the fabric filters should be prolonged. This adds energy usage for cooling *(ref.5)*.

Desulphurization

Coal contains a small amount of sulphur in both organic and inorganic forms typically in the range 0.5-10 wt%. When coal is combusted, the majority of the sulphur is converted to SO_2 and a minor fraction is converted to SO_3 which are emitted to the air if no control measures are implemented. SO_2 emissions is one of the main causes of acid rain which leads to the acidification of soils, forests, and surface waters. In desulphurization, the content of SO_2 is reduced in the flue gas from combustion.

There are mainly three technologies to remove coal sulphur:

- Coal cleaning
- Wet scrubbing
- Dry scrubbing

Coal cleaning
Coal cleaning is an option for removing sulphur from the coal prior to utilization. It also removes mercury. If there is a high concentration of sulphur in the coal, physical coal cleaning is effective in reducing the content, especially if they are present in the coal in relatively high concentrations. The degree of reduction achieved depends on the coal as the composition of the coal can vary greatly. Coal cleaning processes are categorized as either physical cleaning or chemical cleaning where the physical cleaning is typically more deployed. The physical cleaning can be divided into four phases:

- initial preparation,
- fine coal processing,
- coarse coal processing,
- final preparation.

First, in the initial phase, the coal is crushed and classified by screening. Secondly, in the fine and coarse phase, a fluid (normally water) is flushed through coal. The lighter coal particles rise and are removed from the top of the bed. The heavier impurities are removed from the bottom. Finally, the coal must be dried (ref.8).

Wet scrubbing
In wet scrubbing systems, the SO_2 is removed after combustion. Flue gases are brought in contact with an absorbent,

that can be either a liquid or a slurry of solid material where the SO_2 dissolves or reacts with the absorbent. The most normal absorbent is limestone (calcium carbonate) since it is cheap and widely available in large amounts. Other sorbents could be lime, magnesium oxide, ammonia, and sodium carbonate. The removal degree of wet limestone scrubbers is 95%-99% for SO_2 and~60% for SO3. Besides removal of sulphur compounds, wet scrubbers also remove other unwanted species in the flue gas like oxidized mercury and particles. Below is a figure showing an example of a wet scrubber system.

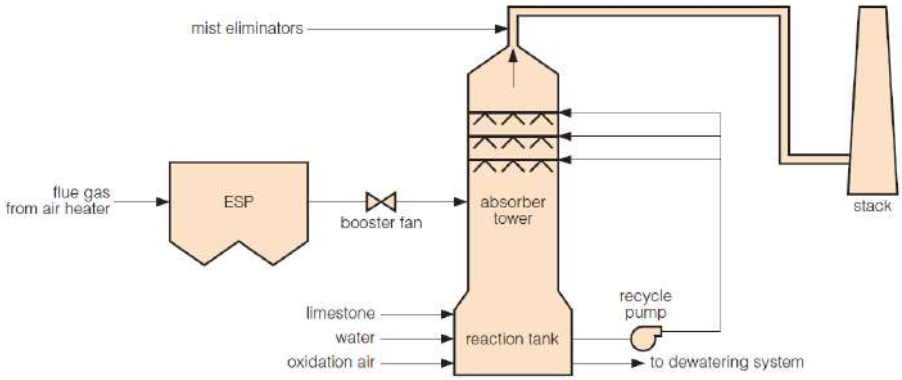


Figure 5. Wet scrubbing system (ref. 6)

The wet scrubbing system in Figure 5 shows a typical system, where the absorber is a spray tower in counter flow. The limestone slurry is pumped and sprayed though the nozzles. The droplets of limestone get in contact with the flue gas, and the sulphur is absorbed and reacts with the limestone. Through the spray tower, the gas is cooled due to the evaporation of water droplets. The flue gas continues its path through the tower and enters the mist eliminator where the rest of the limestone droplets are removed, and the flue gas is emitted to the air. A by-product of the wet scrubber is gypsum that can be collected and sold. (Ref. 6)

In Vietnam, many thermal power plants are located near the sea and here it is normal to use seawater as sorbent to remove SO_2. Sea water is a cheap and available resource and is considered a viable solution for desulphurization However, it also has several drawbacks:

- Compared to limestone, seawater has lower vapor loading capacity since the solubility of sulphur oxides (SOx) in seawater is lower than that of limestone
- High seawater flowrate
- Large equipment size
- Corrosive absorbent, affecting the ocean ecosystem

(Ref. 9)

The efficiency rate of using seawater depends on the flow rate of the seawater. A higher flowrate gives a higher removal of SO_2. However, higher flow rates increase costs and therefore there will be a trade-off between cost and efficiency. For realistic flow rates the efficiency is between 56%-66%. (Ref. 10)

Dry scrubbing

Dry scrubbing includes a dry sorbent, typically dry pulverized limestone. The sorbent needs to grinded to fine parts (20-50 micrometer in diameter). The SO_2 is absorbed and caught by a baghouse filter. The gaseous uptake takes place both as the dry sorbent is injected to the air and at the cakes of sorbent inside the filter. Dry desulphurization systems typically work with low sulphur coal since it requires a high chemical consumption. The removal rate for dry systems is typically somewhat lower than that of wet systems reaching a reduction rates of 50-60% (ref. 6)

Cost estimates

Below are indicative, main economic and performance data summarized. The costs can be added to cost data for pulverized power plants, where these systems are not included. It should be mentioned here, that besides each of these technologies, there also exists combination technologies that simultaneously can remove pollution. These are not described here.

	De-NOx system	**Particles control**	**Desulphurization**
Type of system	SCR	Electrostatic precipitator	Wet limestone scrubbing
Investment costs (M$/MW-e)	0.04-0.05	0.045-0.05	0.28-0.40
Added fixed costs ($/MW-e)	6,300-7,700	5,000-6,000	20,000

Degree of cleaning (%)	85%-92%	98%-99%	95%-99%
Electricity consumption (MWh/MW-e)		2%-4%	1.2%-1.5% for low sulphur coal 1.5%-2.0% for high sulphur coal
Reference	[1]	[4], [7]	[6]

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2. CFB COAL FIRED POWER

Technology Description
A Circulating Fluidized Bed (CFB) boiler is a steam generating plant that burns fuels under special hydrodynamic conditions known as fast fluidized bed. CFB boilers are known for the ability to use a wide range of fuels, having low NO_x emissions and reduced costs for SO_2 removal (Ref. 1).

The typical CFB boiler configuration can be divided in a circulating loop and a convective section:

In the circulating loop, a tall vessel acts as the furnace, where the combustion takes place. Non-combustible solids such as sand, fuel ash or sorbents are placed in the bottom of the furnace to form a hot bed. The fuel particles are introduced near the bottom and they burn in a flameless combustion process at 800-900°C. In order to keep the temperature of the gas that is exiting the furnace at 800-900°C, part of the combustion heat must be extracted. Therefore, heat absorbing surfaces (evaporators) are placed in the furnace, which end up in a steam drum. Inside the furnace, the non-combustible solid particles are lifted and entrained by the primary air input in the bottom and the combustion gas, which provides a condition where solid particles are fluidized. These solids form slender particle agglomerates that are continuously in a circulating loop. When they leave the chamber, they are captured by a gas-solid separator and recirculated through the cyclone back to the bottom of the furnace at a rate sufficient not to cause temperature gradients.

Once the solids are separated, the clean flue gas enters the convective section or back pass. In the top part, the superheater raises the temperature of the steam coming from the steam drum from its saturation temperature to the designed steam temperature for the high-pressure turbine. There is also an economizer, which utilizes low level energy of the flue gas to heat the feed water that is taken to the steam drum. Sometimes the lower part below the economizer is also used as an air preheater.

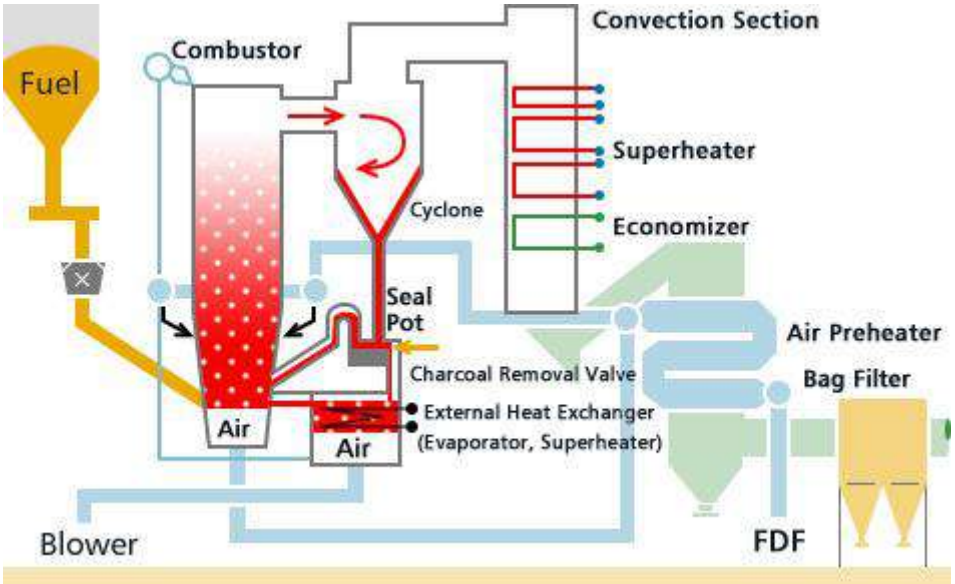


Figure 6: CFB boiler scheme (Ref. 2)

Input
One of the attractive characteristics of CFB boilers is that they can fire a wide range of solid fuels. From low grade coal to biomass or waste fuels. However, fuel particles only compose 1-3% of the solid weight, the rest are non-combustible solids like sand for the fluidized bed, fuel ash or desulphurization sorbents.

Air is also an input for the combustion and there is a primary input at the bottom of the vessel and a secondary air input between the lower and upper zones of the furnace, both previously pre-heated.

Feed water is also used and converted to steam as the means of heat transport (Ref. 3).

Output
The boiler generates steam that can be used for power generation or as a heat output.

Typical Capacities
The capacity typically depends on the type of steam cycle. 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. 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. 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. For a description of steam cycles see the chapter about pulverized coal fired power plants.

The subcritical boilers are normally 300 MW. Supercritical boilers range from 300-600 MW and ultra-supercritical capacity is slightly over 600 MW. (Ref. 4)

Auxiliary consumption is on average 9-10% of the generating capacity (Ref. 5).

Ramping Configurations
CFB boilers are able to quickly respond to varying loads due to the high fluidizing velocity. This makes them able to vary 4% of the Maximum Continuous Rating (MCR) per minute. (Ref. 1).

Advantages
- CFB allows a wide range of fuels, including low-grade fuels and the option of cofiring.
- It is possible to perform a low-cost emission control. The low temperature reduces the formation of nitrogen oxides and allows using limestone for acid gas capture.
- Conventional fossil fuels require the fuel to be grinded and dried before entering the furnace, but this is not necessary with a CFB boiler.
- The higher combustion temperatures found in pulverized fired plants results in more costly materials than for CFB.
- Maintenance is low. The main cause for maintenance is due to the operation of the CFB boiler below ash melting point, the fuel cannot melt, which results in corrosion and fouling (Ref. 6 & 7).

Disadvantages
- The auxiliary power consumption is higher than for pulverized plants due to the high fan power necessary for fluidization (Ref. 5).
- The ability to adjust the load is slightly lower compared to pulverized plants due to the considerable thermal inertia of the large mass of the bed.
- Pulverized coal fired power plants can constitute of units of 1000 MWe and above., CFB plants are generally smaller and as of today, plants over 600 MWe are only under initial operation (Ref. 8)

Environment
As a result of the low combustion temperature and the amount of injected air, NO_2 levels are lower than with PC. On the one hand, nitrogen is not normally oxidized at the low temperatures that CFB boilers operate. On the other hand, by injecting a sub-stoichiometric amount of air, the nitrogen released from the fuel cannot find oxygen in the immediate surroundings.

However, the low combustion temperature forms N_2O. The conversion of coal nitrogen in N_2O depends on the devolatilization process. But when it is heated at a moderate rate up to 900°C, only a small part of the coal converts to HCN, the major source of N_2O.

The formation of Sulfur Dioxide mainly depends on gas residence time, temperature and excess air, but it is favored by high temperature and high pressure. Thanks to the low combustion temperature, it is possible to use limestone to capture SO_2, thus there is no need for back-end scrubbing as wet flue gas desulphurization (FGD).

CFB has lower primary emissions of SOx and NOx than PC boilers. If any slag was to form, the circulating solids can clean the surfaces thanks to the circulation. Nonetheless, compared to a PC boiler with no sulfur capture, CFB boilers with sorbents emit higher amount of CO_2.

The CO emissions for CFB boilers are normally below the regulatory limit, but they increase when the combustion temperature is reduced, especially below 800°C. (Ref. 3)

Employment
For a plant around 500 MW, 1500-2000 people are necessary for the design, construction and commissioning. Such a plant employs 300-350 people with 60 operating the CFB unit. (Ref. 9)

Research & Development
The main research efforts are focused on capacity scale-up, auxiliary power reduction and improvements in SO_2 capture (Ref. 10).

In addition, attaining higher and flexibility is also under research (Ref. 11).

Despite the possibility to use a wide range of fuels in CFB boilers, research is trying to deal with waste biomass as fuels, which can be problematic due to glues and plastics that can agglomerate between the material in the fluidized bed (Ref. 12).

Examples of Existing Projects
CFB boilers have been used in Vietnam for years:

Na Duong power plant.
This coal power plant produces 110 MW (2x55MW) and is owned by Vinacomin. It was completed in 2005 and it is a mine-to-mouth plant. (Ref. 13)

Cao Ngan power plant
This plant also has 2 units of 58 MW and was completed in 2007 with an investment cost of $124 million. It uses Anthracite coal, and the boilers were provided by Alstom (Ref. 14).

Cam Pha power plant
This plant was constructed in two phases: The first one had capacity of 340 MW (configuration of 2 boilers – 1 turbine) that costed $349 million, completed in 2009 and the second phase with capacity 330 MW (configuration of 2 boilers – 1 turbine) was completed in 2010. This plant burns fuel coal or slurry coal (Ref. 15).

The following projects are some of the most recent CFB boilers in Vietnam:

Thang Long power station.
This is a 600 MW coal power plant in northern Vietnam, Quảng Ninh province. It has two units of 300 MW supplied by Alstom and entered commercial operation in May and July of 2018. The plant operates on Anthracite coal from a domestic source. The cost was $645 million (Ref. 16).

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 653 M$ (converted to $2019, the administration, consultancy, project management, site preparation cost, the taxes and interest during construction are not included), equally the nominal investment was 1.49 M$/MW$_e$. The total capital (include these components) was 765 M$, corresponding to 1.74 M$/MW. The fixed O&M cost was 45.7 $/kW$_e$/year and the variable O&M cost was 1.34 $/MWh.

Updated project: CFB: Mong Duong 1
Mong Duong 1 coal-fired power plant located in the Mong Duong Ward, Cam Pha city, Quang Ninh province. The plant includes 2 units of 540 MW and started construction from October 2011 and official operation in January 2016.

Mong Duong 1 thermal plant uses circulating fluidized bed (CFB) combustion and subcritical boiler with superheated steam parameter: main steam pressure is 17.2 Mpa (~ 241 bar), main steam temperature is 541°C. The net electricity efficiency of the plant (name plate) is 35% (LHV).

The plant uses the main fuel of 6a.1 coal dust according to the TCVN 8910: 2015 standard, the average ash and slag content is about 37.5%. Each year it consumes about 3.5 million tons of coal, emits about 1.3 million tons of ash and slag, of which the volume of bottom slag is about 525,000 tons (accounting for 40%) and fly ash is about 787,500 tons (accounting for 60%). Follow the automatic monitoring data of first 6 months 2019, the NO_x emission value is 8.3 mg per Nm^3, the SO_2 is 78 mg per Nm^3 and the $PM_{2.5}$ emission is 102 mg per Nm^3.

The total investment of Mong Duong 1 thermal plant was 1.45 billion $ (converted to $2019, the administration, consultancy, project management, site preparation cost, the taxes and interest during construction are not included), corresponding to a nominal investment of 1.34 M$/$MW_e$. The total capital (include these components) was 1.57 billion $, corresponding to 1.46 M$/MW. Other financial data: fixed O&M cost was 39.16 $/$kW_e$/year, variable O&M cost was 0.97 $/MWh and warm start-up cost was 299 $/MW.

Future developments of CFB boilers in Vietnam:

An Khanh Bac Giang power plant.
It is a 650 MW coal-fired power plant, located in Luc Nam District, Bac Giang province and expect to commission in 2024. It will cost $1 billion. It will use domestic anthracite coal.

Data estimates
To estimate a central case for 2020, international sources on CFB have been collected and used as a basis. For comparison to Vietnamese conditions, data from five Vietnamese CFB plants have been collected. However, the Vietnamese cases are based on subcritical and supercritical technology, while the data sheet represents ultra-supercritical. The ultra-supercritical has been used in the data sheet since this technology is expected to be more deployed in the future compared to subcritical and supercritical. For the projection, a learning curve approach have been used to project financial data. Details on this can be found in the appendix. See Table 7 for local cases.

Table 7. Data for selected CFB power plants in Vietnam. 2020 data. ($2019) (Ref. 20)

Key parameter	Local case 1: Mao Khe 2012	Local case 2: Mong Duong 1	Local case 3: An Khanh	Local case 4: Nong Son 2014	Local case 5: Thang Long 2018
Generating capacity for one unit (MW_e)	220	540	60	30	300
Generating capacity for total power plant (MW_e)	440	1080	120	30	600
Electricity efficiency, net (%), name plate	37.6	35	33	32	35.2
Electricity efficiency, net (%), annual average	31.0	28	27	26	31
Ramping (% per minute)	0.5	0.6	0.5	1.0	1.0
Minimum load (% of full load)	85	70	75	67	65
Warm start-up time (hours)	10	8	6	6	5
Cold start-up time (hours)	12	14	11.2	8	9
Emission $PM_{2.5}$ (mg/Nm^3)	118	102	-	-	-
SO_2 (mg/Nm^3)	472	78	-	-	-
NO_X (g per GJ fuel)	315	8.3	-	-	-
Nominal investment (M/MW_e$)	1.49	1.34	1.78	1.33	1.43
Fixed O&M ($/MW_e/year)	45,700	39,200	45,300	-	-
Variable O&M ($/MWh)	1.34	0.97	1.12	-	-
Start-up costs ($/MW_e/start-up)	240	299	309	262	-

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Data sheet

Technology	CFB boiler power plant ultra-supercritical								
US$2019	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref.
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	600	600	600	300	660	300	800		1;2
Generating capacity for total power plant (MWe)	1,200	1,200	1,200	300	1,200	300	1,800		1
Electricity efficiency, net (%), name plate	41	42	43	37	43	39	45		1;2;3
Electricity efficiency, net (%), annual average	40	41	42	37	43	39	45		1;2;3
Forced outage (%)	7	6	3	5	15	2	7	A	1
Planned outage (weeks per year)	7	5	3	3	8	2	4	A	1
Technical lifetime (years)	30	30	30	25	40	25	40		1
Construction time (years)	4	3	3	3	5	2	4	A	1
Space requirement (1000 m^2/MWe)	-	-	-	-	-	-	-		
Additional data for non-thermal plants									
Capacity factor (%), theoretical	-	-	-	-	-	-	-		
Capacity factor (%), incl. outages	-	-	-	-	-	-	-		
Ramping configuration									
Ramping (% per minute)	4	4	4	2	4	3	4	B	1,4
Minimum load (% of full load)	40	25	20	25	50	10	30	A	1,5
Warm start-up time (hours)	8	4	4	2	8.5	2	5	B	1
Cold start-up time (hours)	10	12	12	6	15	6	12	B	1
Environment									
PM 2.5 (mg per Nm^3)	70	70	70	50	150	20	100	E	3;6;7
SO_2 (degree of desulphuring, %)	90	90	95	90	95	90	99		3;6;7
NO_X (g per GJ fuel)	108	105	38	152	263	38	263	C	6;7;8
Financial data									
Nominal investment (M$/MWe)	1.53	1.52	1.50	0.73	1.82	0.73	1.71	D;F;G	1;7;9;10
- of which equipment (%)									
- of which installation (%)									
Fixed O&M ($/MWe/year)	40,900	39,800	38,500	32,100	53,500	30,100	50,300	F	1;7;9;10
Variable O&M ($/MWh)	0.12	0.12	0.12	0.09	1.01	0.09	0.15	F	1;7
Start-up costs ($/MWe/start-up)	52	52	52	42	104	42	104		12

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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.

3. GAS TURBINES

Brief technology description
A gas turbine is a combustion turbine and uses air as a working fluid to generate electricity.

Simple cycle
The major components of a simple-cycle (or open-cycle) gas turbine power unit are: A gas turbine, a gear (when needed), a generator, a compressor and a burner. In Figure 7 a simple-cycle gas turbine is shown. At 1 there is an air inlet which is compressed (stream 2). In the combustion chamber (C.C.) air is added to the combustion. The heated air and gas (stream 3) are sent to the gas turbine where it is expanded. This makes the shaft and hence the generator rotate. The exhaust gas is released in stream 4.

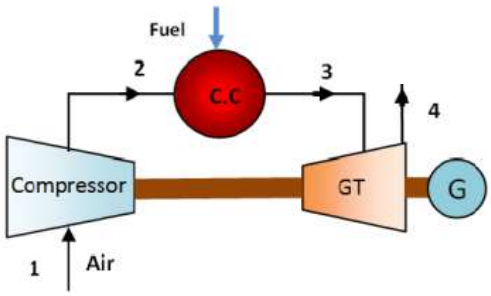


Figure 7: Process diagram of a SCGT (ref. 1)

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%). In the following, small gas turbines are not handled any further.

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 in Figure 8 below.

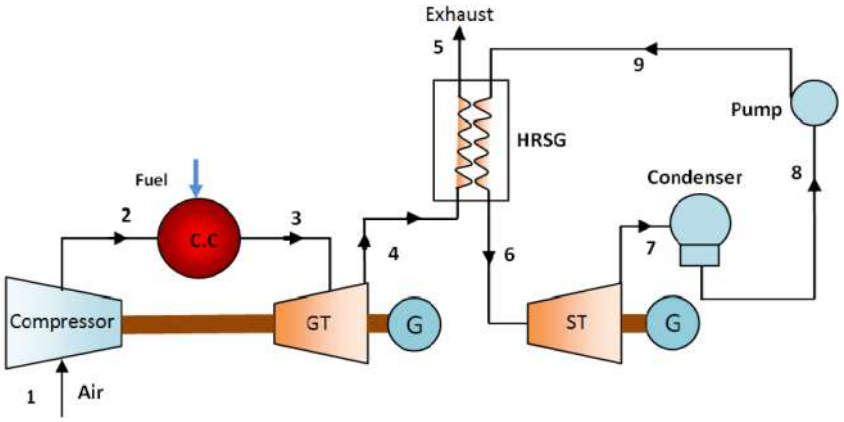


Figure 8: Process diagram of a CCGT (ref. 1)

The gas turbine and the steam turbine might drive separate generators (as shown called multi-shaft) or drive a shared generator (called single shaft). Where the single-shaft configuration (shared) contributes with higher reliability, the multi-shaft (separate) has a slightly better overall performance (higher efficiency). Moreover, using a single-shaft generator reduces the need for individual components and can use the same balance of plant (bop). This has a financial and operational advantages over the multi-shaft generator. On the other hand, the multi-shaft generator has an advantage when it comes to maintenance. The system can drive the two systems independently and use one generator when the other is maintained. It also gives more flexibility in the construction phase and more layout option. (Ref. 6). 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 (lower cooling water temperature can increase the efficiency). The power generated by the gas turbine is typically two to three times the power generated by the steam turbine. A combined cycle gas turbine has an efficiency of 50-60% whereas a single cycle gas turbine has an efficiency of 30-35%.

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. The efficiency of single cycle gas turbines is significantly lower than combined cycles, however they are also much cheaper and therefore 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 (ref. 4).

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 domestic projects
Nhon 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.

Nhon 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 around 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 641 M$ (converted to $2019, the administration, consultancy, project management, site preparation cost, the taxes and interest during construction are not included), corresponding to a nominal investment of 0.85 M$/$MW_e$. The total capital (include these components) was 764 M$, corresponding to 1.02 M$/$MW_e$. The fixed O&M cost was 33.4 $/$MW_e$/year and the variable O&M cost was 0.59 $/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. This includes: 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) (ref. 5). For the unit and plant size the most common size was chosen. See Table 8. 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 gas of 0.027 from Pollution Prevention and Abatement Handbook, 1998.

Table 8: Combined cycle gas turbine, 2020 data from existing local cases, the Indonesian TC and the central estimates for the Vietnamese TC. ($2019)

Key parameter	Local cases data average		Indonesian TC (2020)			Vietnamese TC (2021)
	(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$)	0.80	4	0.78	0.68	0.83	0.80
Fixed O&M ($/MW_e$/year)	30,500	4	24,100	18,100	30,100	30,500
Variable O&M ($/MWh)	0.47	6	0.14	0.10	0.17	0.47
Start-up costs ($/MW_e$/start-up)	73	4	83	62	104	73

In Table 9 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 according to IEA WEO 2016[10]. 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
[10] International Energy Agency, World Energy Outlook, 2016

Table 9: Investment costs of gas turbines in international studies. (Converted to $2019). 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 (2019$/W) All year: 2015-2040**						
	China			India			
SCGT	0.36			0.42			
CCGT	0.57			0.73			
IEA Southeast Asia 2015	**Southeast Asia / 2030 (2019$/W)**						
CCGT	0.70						
Indonesian TC[11]	**2020**			**2030**	**2050**		
	Central	Lower	Upper		Central	Lower	Upper
SCGT	0.80	0.68	1.25	0.76	0.71	0.57	0.83
CCGT	0.75	0.64	0.80	0.71	0.65	0.55	0.70
Vietnamese TC	**2020**			**2030**	**2050**		
	Central	Lower	Upper		Central	Lower	Upper
SCGT	0.61	0.36	1.25	0.59	0.56	0.36	0.83
CCGT	0.80	0.57	0.80	0.72	0.71	0.57	0.80

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).
6. POWER, "Benefits of Single-Shaft Combined Cycle Power Plants", News and Technology for the Global Energy Industries, 2018

[11] Investment costs have been adjusted to $\$_{2019}$ 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

Data sheets

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

Technology	Simple Cycle Gas Turbine - large system								
US$2019	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	50	50	50	35	65	35	65		3
Generating capacity for total power plant (MWe)	100	100	100	35	150	35	150		3
Electricity efficiency, net (%), name plate	34	36	40						1;2
Electricity efficiency, net (%), annual average	33	35	39						1;2
Forced outage (%)	2	2	2						
Planned outage (weeks per year)	3	3	3						
Technical lifetime (years)	25	25	25						
Construction time (years)	1.5	1.5	1.5	1.1	1.9	1.1	1.9	B	3
Space requirement (1000 m^2/MWe)	0.02	0.02	0.02	0.015	0.025	0.015	0.025	B	3
Additional data for non-thermal plants									
Capacity factor (%), theoretical	-	-	-	-	-	-	-		
Capacity factor (%), incl. outages	-	-	-	-	-	-	-		
Ramping configurations									
Ramping (% per minute)	20	20	20	10	30	10	30	C	3;8
Minimum load (% of full load)	20	30	15	30	50	10	40	A	6
Warm start-up time (hours)	0.25	0.23	0.20						3
Cold start-up time (hours)	0.5	0.5	0.5						3
Environment									
PM 2.5 (mg per Nm^3)	30	30	30	30	30	30	30		7
SO_2 (degree of desulphuring, %)	-	-	-	-	-	-	-	E	
NO_X (g per GJ fuel)	86	60	20	20	86	20	86	A;D	3;7
Financial data									
Nominal investment (M$/MWe)	0.61	0.59	0.56	0.36	1.25	0.36	0.83	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 ($/MWe/year)	24,100	23,400	22,700	18,100	30,100	17,000	28,400	B	1-5
Variable O&M ($/MWh)									
Start-up costs ($/MWe/start-up)	25	25	25	19	31	19	31	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/Nm^3 to g/GJ (conversion factor 0.27 from Pollution Prevention and Abatement Handbook, 1998)

E Commercialized natural gas is practically sulphur free and produces virtually no sulphur dioxide

F The investment cost of an aero-derivative gas turbine will be in the higher end than an industrial gas turbine (ref. 5). Roughly 50% higher.

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

Technology	**Combined Cycle Gas Turbine**								
$2019	**2020**	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data				**Lower**	**Upper**	**Lower**	**Upper**		
Generating capacity for one unit (MWe)	750	750	750	200	800	200	800		1
Generating capacity for total power plant (MWe)	1,500	1,500	1,500	200	1,600	200	1,600		1
Electricity efficiency. net (%). name plate	56	60	61	45	62	55	65		1;3;5;10
Electricity efficiency. net (%). annual average	52	59	60	39	61	54	64		
Forced outage (%)	5	5	5	3	10	3	10		1
Planned outage (weeks per year)	5	5	5	3	8	3	8		1
Technical lifetime (years)	25	25	25	20	30	20	30		1
Construction time (years)	2.5	2.5	2.5	2	3	2	3		1
Space requirement (1000 m^2/MWe)	-	-	-	-	-	-	-		
Additional data for non-thermal plants									
Capacity factor (%). theoretical	-	-	-	-	-	-	-		
Capacity factor (%). incl, outages	-	-	-	-	-	-	-		
Ramping configurations									
Ramping (% per minute)	7	20	20	10	30	10	30	C	1;2
Minimum load (% of full load)	56	30	15	30	50	10	40	A	5
Warm start-up time (hours)	2	1	1	1	3	0.5	2	A	1;5
Cold start-up time (hours)	3	2	2	2	5	2	5		1;5
Environment									
PM 2,5 (mg per Nm^3)	30	30	30						
SO_2 (degree of desulphuring. %)	-	-	-	-	-	-	-	E	
NO_X (g per GJ fuel)	78	60	20	20	86	20	86	A;D	7;8
Financial data									
Nominal investment (M$/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

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

3 IEA, World Energy Outlook, 2015.

4 Learning curve approach for the development of financial parameters.

5 Siemens, 2010, "Flexible future for combined cycle".

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

7 Maximum emission from Minister of Environment Regulation 21/2008

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

9 Soares, 2008, "Gas Turbines: A Handbook of Air, Land and Sea Applications".

10 IEA, Projected Costs of Generating Electricity, 2015.

Notes:

A Assumed 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/Nm^3 to g/GJ (conversion factor 0.27 from Pollution Prevention and Abatement Handbook, 1998)

E Commercialized natural gas is practically sulphur free and produces virtually no sulphur dioxide

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

4. CO_2 CAPTURE AND STORAGE (CCS)

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

CO_2 Capture
The CO_2 volume of fossil fired power plants ranges from 3-15% of the flue gas volume. The carbon capture process can take place prior to combustion, after combustion or via oxy-fuel combustion (Ref. 1).

1. **Post-Combustion Capture**

   In post-combustion capture, the CO_2 is separated from the flue gas. The dominant post-combustion technology is absorption or scrubbing of CO_2 in chemical solvents like amine solutions, which are commercially available for industrial purposes, but not for power plants yet. The CO_2 is stripped from the solvent by raising the temperature (Ref. 2).

2. **Pre-Combustion Capture**

   In pre-combustion capture, the CO_2 is captured prior to combustion as in coal gasification or natural gas decarbonization, where hydrogen and carbon dioxide are produced. The hydrogen is used as a fuel and the CO_2 is removed (Ref. 1). The most common separation technology are solvents, which scrub the CO_2 out of the syngas and then release it at high temperature or low pressure. This requires additional thermal power that can add-up to 15% of the net power output for both, pre- and post-combustion. Amine-based solvents are the most widespread (Ref. 3).

3. **Oxy-Fuel Combustion Capture**

   In Oxy-fuel combustion the nitrogen in the air is removed by an Air Separation Unit (ASU), so the fuel is combusted in an atmosphere of oxygen and recycled CO_2. As an alternative to the ASU, surplus oxygen from electrolysis plants can be used to feed the combustion. This results in a flue gas that only contains water vapor and CO_2, where the water vapor can be condensed easily, giving a highly concentrated CO_2 steam (Ref. 4).

In all three methods, once the CO_2 is captured, it later needs to be compressed and transported to storage.

CO_2 compression and liquefaction
The major barrier for extensive use of CO_2 removal technology are the high costs of separating and compressing the CO_2. The additional energy required for this process typically reduces the efficiency by 10%. To transport the CO_2 by pipeline, a suitable pressure for transport is 10 to 20 MPa, whereas to be transported by ship, it needs to be liquified.

CO_2 transportation
It is necessary to transport the captured CO_2 from the power plant to a suitable reservoir, where it can be injected and permanently stored. This is believed to be feasible by using pipelines. The pipeline costs are proportional to distance, but they may increase in congested and heavily populated areas by 50 to 100% compared to pipelines crossing remote areas like mountains, natural reserves or roads. Offshore pipelines are 40-70% more expensive to similar pipelines on land. Alternatively, ships like LPG tankers, can be used, where the cost is less dependent on distance. However, there are step-in costs which include a stand-alone liquefaction unit, potentially remote from the power plant. Therefore, for short to medium distances and large volumes, pipelines are the most cost-effective solution.

CO_2 storage
Relevant storage concepts are using the CO_2 for Enhanced Oil Recovery (EOR) or geological storage in deep saline formations, both onshore and offshore. The former consists in injecting CO_2 in declining oil reserves so that pressure

favors oil displacement and extra oil is extracted (Ref. 5). The latter is the most widespread storage method for long term CO_2 storage, and saline aquifers have a large potential volume and are common (Ref. 4).

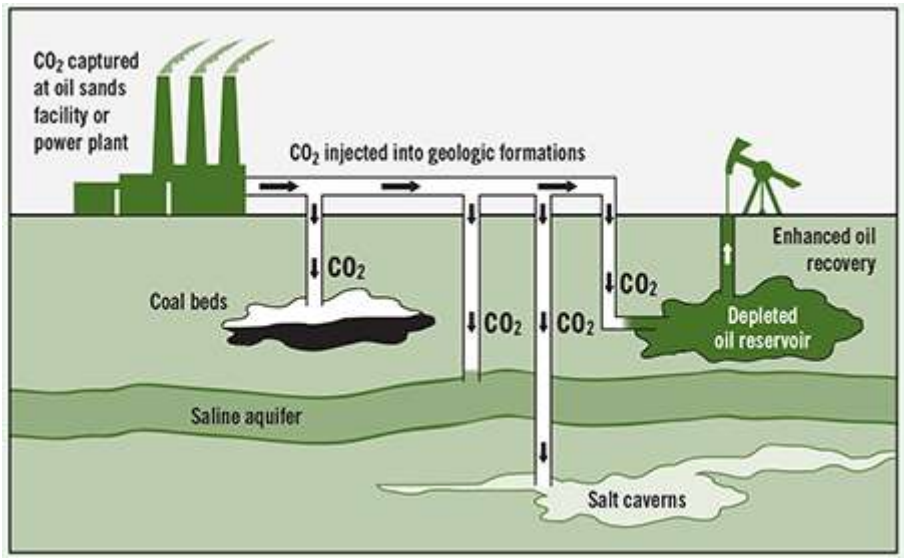


Figure 9. Post-capture treatment of CO_2. Source: Energywatch

Vietnam is one of the few countries in Southeast Asia that has promising CO_2 storage potential. A study of the location of depleted oil and gas reservoirs, saline aquifers and coal formations was done in a collaboration between the French and Vietnamese geology and mineral research offices. Figure 10 shows the results from the study. CO_2 sources in red dots, and the storage sites need to comply with the following characteristics to be considered suitable:

- The sediment formations are deeper than 1000 meters.
- They should be 20 km away from major faults or oil fields.
- No further than 100 km from the emitting source (when it emits over 2.5 $MtCO_2$/year)

It can be seen that there are offshore storage opportunities near most of the CO_2 sources (Ref. 6).

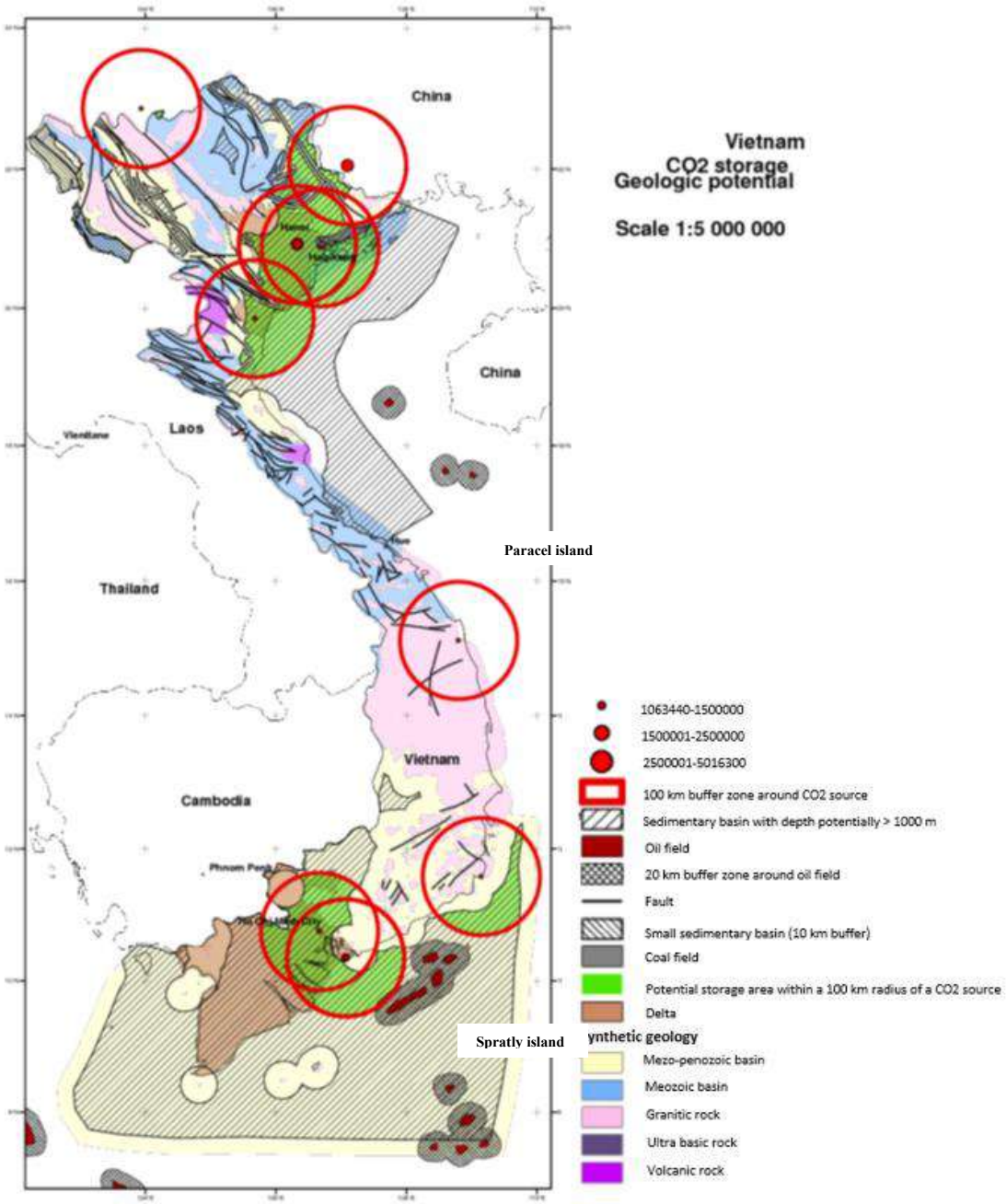


Figure 10: CO_2 storage potential in Vietnam. The Paracel and Spratly Islands of Vietnam are not shown in the map (Ref. 6)

Input

- In pre-combustion capture, syngas (predominantly H_2, CO and CO_2).
- In post-combustion capture, CO_2 in flue gas from power plant combustion.
- In the oxy-fuel combustion, a stream of CO_2 and H_2O where CO_2 is found at relatively high concentrations.

Output

The main outputs are stored CO_2 and CO_2-lean flue gas, but if it is not stored, CO_2 can be converted into value-added products for the food and drink industry or for manufacturing chemical products (Ref. 4).

Ramping

The ability to regulate a power plant is not influenced by adding post-combustion capture. However, the CO_2 content of the flue gas decreases at part load, consequently, the capture costs per tonne increase. For this reason, it may be preferred to operate CCS plants at base load.

Advantages

- **Post-combustion capture**. It can be applied to most of the existing coal-fired or thermal power plants.

- **Pre-combustion capture**. Syngas is concentrated in CO_2 and at high partial pressure, which extends the range of technologies available for separation and allows a reduction of the compression costs. This results in a lower operational cost than post-combustion capture.
- **Oxy-fuel combustion**. Very high CO_2 concentrations in the flue gas, so complex post-combustion separation can be avoided; CO_2 is obtained by getting rid of the water through simple condensation. Power plants can also be retrofitted in order to include oxy-fuel combustion (Ref. 7).

Disadvantages

- **Post-combustion capture**. The CO_2 is diluted in the flue gas and at ambient pressure, which makes it harder to sequester the CO_2. The technology needs large amounts of thermal power for the regeneration of the carbon capturing substance.
- **Pre-combustion capture**. The cost of equipment is high, and it requires supporting systems as an air separation unit and a shift converter. Suitable for IGCC plants; natural gas plants need an *auto-thermal reforming* process before fuel utilization.
- **Oxy-fuel combustion**. Cryogenic O_2 production is expensive. Recycling the cooled CO_2 is necessary to maintain temperature within combustor materials, which decreases efficiency and adds auxiliary load (Ref. 7).

More generally, leakage during transportation or storage can lead to disastrous issues like ocean and soil acidification. It can occur due to fractures and faults on the earth crust (Ref. 8). Cost of CCS and lack of a CO_2 economy have been identified as the major challenges preventing the widespread adoption of this technology (Ref. 9).

Environment

CCS has an overall positive effect on air pollution, however, it requires 15-20 % of the energy produced by a power plant, depending on the technology that is being used. This corresponds to an efficiency drop of 7-8%-points. This means that the emissions of some pollutants will increase not only in the facilities, but also in the emissions caused by extraction and transport of the additional fuel.

- **Sulphur dioxide** (SO_2). SO_2 emissions in coal fired plants fall when CO_2 is captured, plants with CCS are normally equipped with improved Flue Gas Desulfurization (FGD). IGCC plants already have low SO_2 emissions regardless of CCS due to the Acid Gas Removal section.
- **Particulate matter (PM) & nitrogen oxide** (NO_x). They are expected to rise proportionally with the increase in primary energy use due to the reduction in efficiency caused by CCS. NOx and PM are not caught by the amine system, and therefore emissions grow pr. output when fuel consumption pr. output increases. However, the emission level is the same pr. GJ fuel (Ref. 10).
- **Ammonia** (NH_3). It is the only pollutant for which a significant increase in emissions is expected, due to the degradation of amine-based solvents (Ref. 8).

Research and Development

Despite governmental efforts to boost renewables and natural gas, the country's coal usage is on the rise since 2012, showing a growing reliance on coal (Ref. 11), which is the main source of CO_2 emissions (Ref. 12).

Even with an energy sector reliant on coal, there are no research initiatives that target Carbon Capture and Storage in Vietnam. CCS is not a priority for Southeast Asia, and the governmental efforts are focused on renewable energies and natural gas to transition towards a low-carbon economy rather than CCS.

Nonetheless, the policy framework supports retrofitting CCS, which is a key factor for its future, in order to avoid carbon emission lock-in and future inability to operate (Ref. 6). An advantage for implementing CCS is that the country does not need to change the structure of its energy system. The Asian Development Bank argued that mitigation through CCS could become economically feasible in Southeast Asia as carbon prices rise towards 2050.

All the studies in Vietnam have been internationally sponsored (Ref. 6). However, more studies are necessary concerning CCS potential in Vietnam, and they should not only focus on storage potential, but also on technical and economic aspects.

Existing Installations
The existing CCS projects are one-off in Southeast Asia, and more so in Vietnam. Only two projects have been implemented:

The White Tiger project
This is the first commercial CCS project in Asia; therefore, it has a high demonstration value. The project is a collaboration between Mitsubishi Heavy Industry, Marubei and Vietsovpetro. It captures CO_2 from a combined cycle natural gas power plant and injects it in the white tiger field with Enhanced Oil Recovery purposes. The CO_2 is transported through 144 km of undersea pipelines and it is stored at a depth of 4km. The carbon capture is 4.6 Mtpa (Ref. 13).

The Rang Dong project
A small CO_2-EOR pilot was conducted between 2011-2014 and the results demonstrated the technical feasibility of the project. However, HGC (Hydrocarbon Gas) EOR was more cost-effective due to inconvenient offshore location and it has been operating as a commercial HGC-EOR since 2014 (Ref. 14).

Petra Nova Carbon Capture
This power plant located in Texas has the world's largest post-combustion CO_2 capture system. It has been operating since 2017, when it was retrofitted with a 1.4 Mtpa (Mega-ton-per-annum) CO_2 capture facility (Ref. 15). CO_2 is sent to an off-site oil field. In Summer 2020, the Petra Nova carbon capture power project went offline due to low oil prices following on the Covid-19 pandemic.

Tuticorin CCU Project
This project is a carbon capture and utilization system in Chennai, India, started operating in 2016 for a power plant with 5 coal-fired units of 210 MW each (Ref. 16). It can capture 60.000 CO_2 tonnes/year from the flue gas, which is utilized for baking soda and ash. The technology is running without subsidy due to a new CO_2 stripping chemical, which is slightly more efficient than amine (Ref. 17).

Shanghai Shidongkou 2nd Power Plant Carbon Capture Demonstration Project
It is a coal-fired 600 MW demonstration plant for post-combustion carbon capture in China The project started in 2009 and started operation in 2011, with a cost of $24 million. The Carbon Capture technology used is post-combustion capture using an amine mix. After capture, the CO_2 is sold for commercial use (Ref. 18).

Boundary Dam Unit#3
The coal-fired station is located in Canada. It produces 115 MW of power and post-combustion CCS was installed in 2014. The capture rate is up to 90% and the plant sequesters around 1 million tonnes a year with amine technology. The project had a cost of $1.24 billion, of which half went for CCS installation and the other half for plant modernization. CO_2 is sold for EOR purposes (Ref. 19).

Data estimates
Cost figures are given as an additional cost with respect to the same technology without CCS. Data is shown for a retrofit with post-combustion technology. Efficiency and energy data are shown as differences compared to the technology without CCS since CCS technology cannot stand alone. Data estimates for 2020 is based on a number of international sources and the Danish technology catalogue since the experiences from Vietnam on CCS are limited. The projections follow a learning curve approach relative to the learning rates used for coal and gas fired power plants. See appendix 1 for a description of the learning curves. The data estimates only include the carbon capture, not the sequestration part. Therefore, compression, transport and storage etc. is not included in the data.

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Technology	Supercritical coal power plant with CCS - Retrofit post-combustion								
US$2019	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	-60	-60	-60					A	1
Generating capacity for total power plant (MWe)	-60	-60	-60					A	1
Electricity efficiency, net (%-point), name plate	-7	-7	-7						1
Electricity efficiency, net (%-point), annual average	-8	-8	-8						1
Forced outage (%-point)	+7	+7	+7						
Planned outage (weeks per year)									
Technical lifetime (years)									
Construction time (years)									
CO_2 emission reduction (%)	-89	-90	-90			-90	-99	B	1
Space requirement (1000 m^2/MWe)									
Ramping configuration									
Ramping (% per minute)	4	4	4					C	7
Minimum load (% of full load)	30	30	30					D	7
Warm start-up time (hours)	4	4	4					E	8
Cold start-up time (hours)	12	12	12					E	8
Environment									
PM 2.5 (mg per Nm3)	81	81	81						3,7
SO_2 (degree of desulphuring, %)	97	97	97						3,7
NO_X (g per GJ fuel)	152	150	38						3,7
CH_4 (g per GJ fuel)									
N_2O (g per GJ fuel)									
Financial data									
Nominal investment (M$/MWe)	+2.03	+1.86	+1.48	+1.66	+2.38	+1.22	+1.74	F	2,5,9,10
- of which equipment (%)	30	30	30	25	50	25	50		1
- of which installation (%)	70	70	70	50	75	50	75		1
Fixed O&M ($/MWe/year)	+43500	+42100	+40900	+13500	+52000	+13500	+52000	F	1,7,9
Variable O&M ($/MWh)	+3.22	+3.13	+3.03	+2.60	+8.52	+2.44	+8.02	F	1,5,9

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8 IEAGHG, Operating Flexibility of Power Plants with CCS

9 NREL ATB 2020

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

Notes:

A The difference in output power represents the additional power required by the auxiliary equipment (with CCS, ~15% of the net output).

B This figure represents the efficiency of the capture process. New technologies might remove CO_2 more efficiently in the future. CO_2 can be already captured at higher rates, but costs to marginally increase capture rates beyond the reported values are relatively high.

C In principle, ramping is not affected by the presence/absence of CCS.

D Minimum load is not affected by CCS. However, the CO_2 compressor requires higher loads for smooth operability.

E The regeneration in the post-combustion unit has a start-up time comparable to that of the power plant.

F Compression, transport and storage are not included in the figures.

Technology	Natural Gas Combined Cycle with CCS - Retrofit post-combustion								
US$2019	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	-40	-40	-40					A	1
Generating capacity for total power plant (MWe)	-40	-40	-40					A	1
Electricity efficiency, net (%), name plate	-7	-7	-7						1
Electricity efficiency, net (%), annual average	-8	-8	-8						1
Forced outage (%)	+5	+5	+5						
Planned outage (weeks per year)									
Technical lifetime (years)	-								
Construction time (years)									
CO_2 emission reduction (%)	-87	-90	-90			-90	-99	B	1
Space requirement (1000 m^2/MWe)									
Ramping configurations									
Ramping (% per minute)	20	20	20					C	6
Minimum load (% of full load)	45	45	45					D	6
Warm start-up time (hours)	2.0	2.0	2.0					E	4
Cold start-up time (hours)	4.0	4.0	4.0					E	4
Environment									
PM 2.5 (mg per Nm3)	30	30	30						3,6
SO_2 (degree of desulphuring, %)	99	99	99						3,6
NO_X (g per GJ fuel)	78	60	20						3,6
CH_4 (g per GJ fuel)	-	-	-						
N_2O (g per GJ fuel)	-	-	-						
Financial data									
Nominal investment (M$/MWe)	+1.20	+1.01	+0.78	+0.88	+1.62	+0.62	+1.06	F	1,7,8
- of which equipment (%)	40	40	40	30	60	30	60		1
- of which installation (%)	60	60	60	40	70	40	70		1
Fixed O&M ($/MWe/year)	+9400	9,000	8,800	7,300	14,600	6,900	14,600	F	1,7,8
Variable O&M ($/MWh)	+1.25	+1.21	+1.17	+0.62	+4.16	+0.62	+4.16	F	1,7,8

References:

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

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

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

4 IEAGHG, Operating Flexibility of Power Plants with CCS

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

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

7 NREL ATB 2020

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

Notes:

A The difference in output power represents the additional power required by the auxiliary equipment (with CCS, ~10-15% of the net output).

B This figure represents the efficiency of the capture process. New technologies might remove CO_2 more efficiently in the future. CO_2 can be already captured at higher rates, but costs to marginally increase capture rates beyond the reported values are relatively high.

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D Minimum load is not affected by CCS. However, the CO_2 compressor requires higher loads for smooth operability.

E The regeneration in the post-combustion unit has a start-up time comparable to that of the power plant.

F Compression, transport and storage are not included in the figures

5. INDUSTRIAL CO-GENERATION

Introduction to industrial cogeneration

Cogeneration is the use of a power production plant to generate electricity and useful heat at the same time. In industrial cogeneration, it is typically waste heat from various industrial processes, that are used to heat a boiler, that in turns drives a turbine connected to a generator, which generates electricity. This sort of setup can be used in many industries such as chemical plants, steel and cement manufactories, pulp and paper mills etc. that all have high temperature processes as part of the manufacturing chain, though some processes are more suited for the utilization of waste heat than others. This waste heat is not always utilized and can therefore represent a source of efficiency gains for the industrial process if utilized for cogeneration, as well as an opportunity to improve the operations profitability, if fuel costs are a substantial part of the expenses.

Cogeneration can also be used in connection to domestic heating purposes and is then more typically known as Combined Heat and Power (CHP) plants that provide both electricity and heat for normal consumers. The industrial cogeneration differs from CHP not in the general principle of the generation process, but rather in the application of the heat to the industrial process itself. While heat recovery is not strictly speaking cogeneration, it has some similarities and uses in an industrial setting, especially in lower temperature processes, where heat is used for e.g. drying such as is seen in the textile industry and other industries, and the temperatures are too low to be used effectively for electricity generation. In these situations, heat recovery can reduce the production costs, and increase the overall efficiency of the process.

The particulars of a given industry and its processes, and the factory or plant that would be using cogeneration, is very important for how a solution should be implemented, the efficiency of the electricity generation that might be realized and the profitability of doing so. This chapter cannot cover all the different industries and applications and the focus will therefore instead be on two general approaches to cogeneration and discuss the application of them to two particular industries. The principles behind these cogeneration approaches will however be relevant for other similar industries. Estimates of costs and efficiencies will be given in the form of datasheets, but it is important to stress, that these could vary dramatically depending on the specific context of any given factory or manufacturing plant where it would be implemented.

The two general approaches will be one in which the industrial process leaves an organic by-product, that can be incinerated for the release of energy, and one where excess process or “waste” heat can be utilized or power production. In both cases the heat would be transferred to a boiler where water is made into steam that drives a turbine which produces electricity. Depending on the industrial process and the temperatures employed, the excess heat from this process could be used either for process heat further down the production line, in some cases in district heating or simply be cooled away.

Incineration of an organic by-product of the production to heat a boiler connected to a turbine, is in principle very similar to biomass-fired CHP plant. A fuel is loaded into an incinerator and burnt, and the heat energy is transferred to a water boiler which produces steam. The steam is then led through a turbine and electricity is generated. The process generally performs the same regardless of the material being burned, though the chemical properties of the organic material that is incinerated and its residues can vary a lot from process to process, and the boiler and incinerator needs to be built to handle it.

The other approach that will be examined in this chapter is where the heat source is indirect and doesn’t come from a boiler, but rather from the industrial process itself. This can for example be from the clinker in a cement line or the smelters in the steel industry, where high temperatures are used in the process and the excess heat can be directed towards heating a boiler, that produces steam which can be led through a turbine. The principle of generating electricity is therefore the same in both cases, but the practicalities of implementation, the costs and efficiencies of the processes can vary substantially depending on the particulars.

Industry in Vietnam

Industry in Vietnam is diverse and consists of several different sectors. The largest single sector is the cement industry, that accounts for a final energy consumption of 211.8 PJ. Other notable sectors, where industrial co-generation is viable, are paper, pulp and printing sectors that account for 98.3 PJ, food and tobacco processing at 73.1 PJ, textile and leather at 58.2 PJ and iron and steel at 55.9 PJ. These sectors are also identified in the Vietnam Energy Outlook 2019 report as being the most significant ones for further energy efficiency initiatives (EREA & DEA, 2019). Total industrial energy consumption is 935.1 PJ.

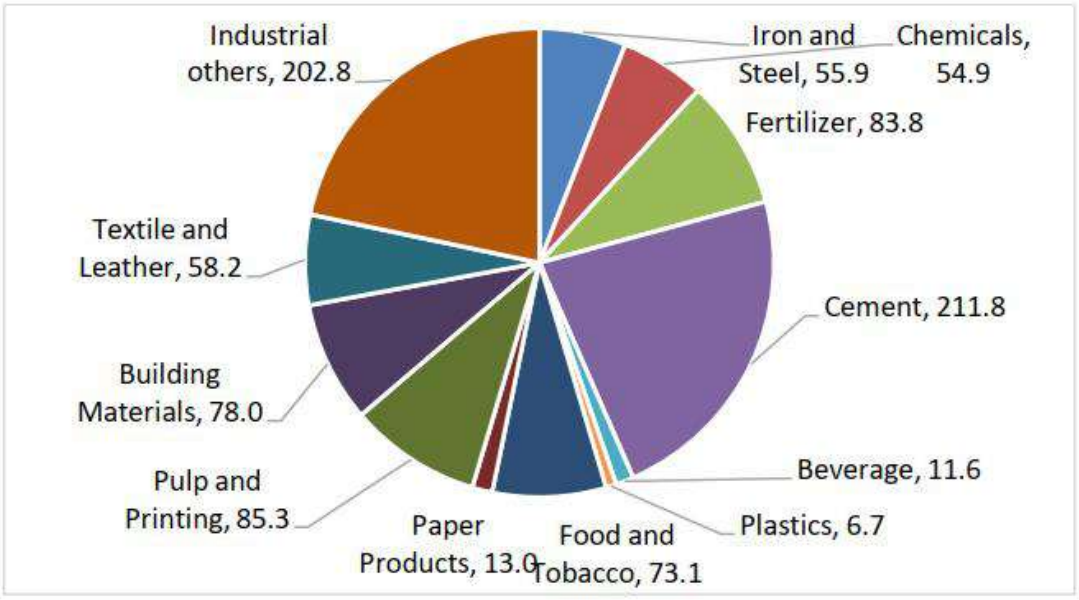


Figure 11: Breakdown of energy consumption in PJ by industry sector in Vietnam 2014 (Institute of Energy, 2019)

As can be seen from the Figure 11 above, Vietnam has a large and diverse industrial sector. Many of these industries use high temperature process heat in their production. Not all those with high temperatures, however, are necessarily suitable for cogeneration, if the heat energy is too dissipated and therefore difficult to utilize in heating a boiler.

A good example of an industry with potential for using an organic by-product in cogeneration, is the sugar industry in Vietnam, that has already adopted the use of cogeneration in most of their sugar mills. Most of these produce heat and electricity for self-use only, however, and only a select few produce electricity that is sold on the national grid. Sugar mills use the discarded husks of sugar cane, the bagasse, as fuel for biomass fired boilers where the steam drives a turbine connected to a generator. This means that most of the sugar-mills do not produce electricity outside of the sugar-season, meaning that there remains a potential for utilizing many of the cogeneration facilities at sugar plants more by using other forms of available biomass such as e.g. rice husks.

The paper, -pulp, and -printing industries likewise have the possibility of using CHP biomass boiler, as the production of paper leaves a tar-like energy rich by-product popularly called “black liquor”, that can be burned in biomass boiler and used to generate heat and power.

While the sugar industry and paper industry are very different, cogeneration in them can be handled with a similar system of biomass CHP boiler system. Such a system can be used in many similar industrial processes with relatively high heat process temperatures and organic materials being used. As such, this is one of the cogeneration technologies, that will be described in this technology catalogue section.

The cement industry is one of the more energy intensive industries in Vietnam, and even with improvements in technology that has been applied to the production of cement in later years (Xim Ang, 2020), there is inherently a lot of wasted heat in the cement production process that could be used with co-generation to increase efficiency of the process. Vietnam power demand is forecasted to continue develop at a high rate, and so reducing power demand by using excess heat to generate electricity would benefit not only heavy industry producers but also the broader power system. According to calculations from an article from the Vietnamese Cement Association, one ton of exhaust gas can generate between 3 and 4 kWh of electricity. Cement factories typically use two main forms of energy: thermal energy from coal, which is used mainly for clinker and calciner kilns in the actual cement production process., and electricity that is used to power machinery and equipment, auxiliary systems (such as air pumps, water pumps etc.) and lighting, offices and similar. With coal and electricity being the main energy sources for cement production, utilizing excess heat can help decreasing costs and greenhouse gas emissions.

Heavy industries with high temperature processes like steel and cement production, are candidates for the other type of cogeneration practice, where waste heat from high temperature processes is directed towards heating a boiler connected to a turbine. There are some examples of this method being applied in the cement industry in Vietnam already, which is the largest single industrial sector going by energy consumption, and the use of cogeneration of

this kind in the cement industry will be the other approach studied in this chapter.

Brief technology description
As mentioned above, two CHP technologies that are useable for industrial cogeneration will be discussed here. These two technologies are biomass-fired CHP boiler-system and CHP systems heated with process heat. The focus will be on the principles underlying these technologies and their structures, as they can be fitted to many different processes and be built for very different specifications depending on the specific needs of any given industrial process.

Biomass-fired CHP boiler:
The biomass-fired CHP boilers can come in many different varieties that are able to handle different types of fuel, that have different chemical compositions and incineration characteristics. The general concept of a biomass-fired CHP boilers is biomass being fed into a combustion chamber connected to a boiler. While the concept of biomass-fired CHP plants is very similar to a more conventional oil- or gas fired plant, the operation of the biomass-fired power plant is in some ways more complex and can require more staff-hours to operate. This is partly due to the relatively low heating value and bulk density of biomass compared to fossil fuels, which means it requires more storage space and more time handling and feeding into the boiler. The machinery will require more maintenance to ensure continued high performance of the equipment.

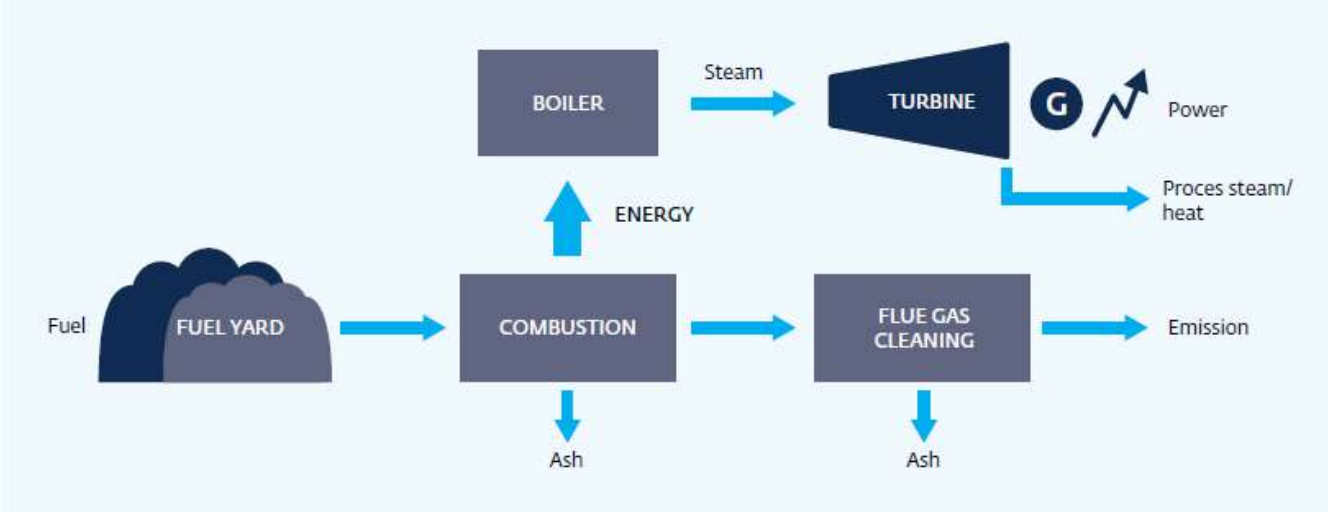


Figure 12: A schematic of a biomass fired co-generation plant (International Finance Corporation, 2017).

The Figure 12 above sketches the structure of a biomass fired CHP plant. The figure shows the feeding of biomass into the furnace beneath the boiler. This requires an area for fuel storage and handling and a conveyor belt or similar to feed the biomass into the furnace. The furnace is connected to a boiler, where water is heated, which is connected to a steam turbine process where steam is heated and run through a turbine connected to a generator (International Finance Corporation, 2017).

One of the challenges with biomass-fired CHP, is the issue of deposits of ash and slag in the furnace. Fuels with a high alkaline content, such as e.g. straw, can create slags in the bottom and the sides of the furnace, which can corrode the furnace and boiler and reduce efficiency (Ministry of Energy and Mining, 2011).

Process-heated CHP:
In cement-plants and other higher temperature industrial processes that do not produce organic by-products, that can be burned as was the case with the biomass-fired CHP boiler, the alternative is to use the process heat as a source for heating water in a boiler. For this to work the heat, that is often dissipated in the process, needs to be focussed and harnessed. This should ideally happen as close to the highest temperature point in the process, in order to maximize the heating potential of the process energy. One way to do this is to connect a heat recovery boiler with either a closed loop of steam heated near the burning of coal for cement production, or by utilizing hot exhaust gas from the process, as depicted in the Figure 13 below. The schematic is a representation of the Organic Rankine Cycle cogeneration operation in a Portland cement factory, due to the process ability to convert heat to electricity at relatively low temperatures. The hot exhaust gas can reach temperatures of 330 °C, which is relatively low in comparison to the temperatures reached with the biomass-fired CHP. The circuit operates with a minimum of 250 °C for the exhaust gas.

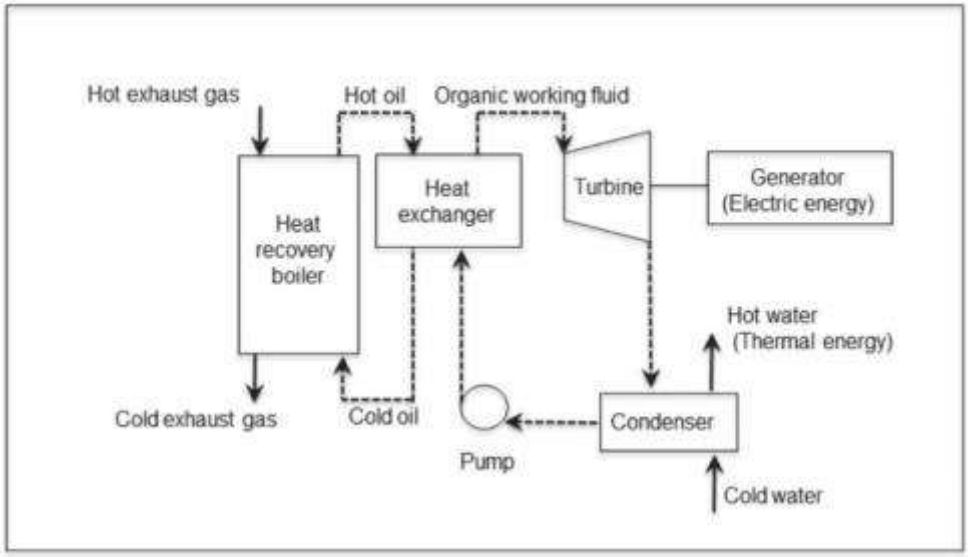


Figure 13: Schematic of cogeneration scheme in a Portland cement factory (Paredes-Sánchez, 2015).

In the cogeneration cycle represented above, hot exhaust gas from the coal burning, that is transferred in a heat recovery boiler to the medium of oil. It is also possible to use steam for this heat transfer, but this typically requires higher temperatures to work, but can achieve higher efficiencies than with oil. The hot oil then heats water through the heat exchanger to steam that is then run through a turbine collected to a generator producing electricity.

Input

Biomass can be of many different types, and their characteristics in terms of chemical composition, calorific value and incineration process and waste. The fuel can be materials like sugar bagasse, rice husks, residues from wood industries, wood chips, straw, paper pulp or similar.

The input to process-heated CHP cogeneration systems is either high temperature exhaust gas or superheated and pressurized steam heated by e.g. coal-fired furnaces used in cement or steel factories.

Output

Biomass fired CHP boilers produce both electricity and heat in the form of steam, or hot (> 110 °C) or warm (< 110 °C) water that can be used for process heat.

In the example of the Portland cement factory, 19,2% of the energy in the preheater exhaust gas could be recovered and used in the production of electricity, allowing that plant to produce 5.5 GWh/year of electricity and 23.7 GWh/year of thermal energy (Paredes-Sánchez, 2015).

The total available thermal energy (Q_T) from the preheater exhaust gas mass flow (m_2) can be calculated as follows:

$$Q_T = m_2 * \left(h_{Hot\ exhaust\ gas\ (330\ °C)} - h_{cold\ exhaust\ gas\ (250\ °C)}\right)$$

$$Q_T = 57.11 \frac{kg}{s} * (610.4 - 527.0) \frac{kJ}{kg} = 4{,}763\ kW$$

An overall efficiency (η) of 85% is estimated for the recovery of heat in the cogeneration Organic Rankine Cycle (ORC) process.

$$Q_{ORC} = \eta * Q_T = 4{,}049\ kW$$

Since 18% of the recovered energy can be transformed into electricity, it's possible to achieve a power output of 729 kW. With 7,500 operating hours per year at the plant, this comes to an electricity production of 5.5 GWh/year for a cement plant with a production of cement of 1.7 kt/day.

Typical capacities

The larger the boiler, the higher the capacity of the electricity generation can be, and the larger part of total production electricity can become. The typical thermal and electrical output for biomass CHP system is described below:

Table 10: Typical capacities of biomass CHP boiler systems (Energinet, 2020).

Typical capacities	Thermal input	Electrical output
Large scale CHP	>100 MW_{th}	~ >25 MW_e
Medium scale CHP	25 – 100 MW_{th}	6 – 25 MW_e
Small scale CHP	1 – 25 MW_{th}	0.1 – 6 MW_e

Cogeneration in cement plants can in principle scale in the same way that biomass-fired CHP plants can, as expressed in the Table 10 above. The size is directly dependent on the size of the cement production, however, as the heat used in the process derives directly from the production of cement, and the efficiencies are likely to be lower than for biomass-fired CHP, as the operative temperatures are relatively low, usually not being higher than 3-400 °C (Irungu & Muchiri, 2017).

Ramping configurations

Advantages/disadvantages

Advantages:

Utilising cogeneration in various industries can help significantly increase the total energy efficiency of the process, by utilising energy in the process heat, that would otherwise have been cooled away. In cement factories, as much as 35% of input energy is typically being lost in waste heat streams (Khurana, Banerjee, & Gaitonde, 2006).

Disadvantages:

Given the relatively low efficiencies of many of the cogeneration processes, it might not always be the most profitable investment of capital in industries.

Environment

The example of the Portland cement factory calculated that the energy recovered through cogeneration was equivalent to 3,000 t coal/year, which at a cost of 100$/ton represents about 0.31 million dollars per year. The CO_2-equivalent greenhouse-gas emissions of this thermal energy assuming coal as the input is around 8,000 tons per year (Paredes-Sánchez, 2015).

Employment

The staff required to operate a biomass-fired plant varies substantially by the size of the operation. A smaller plant in the 1 to 5 MWe range can typically be operated and maintained by a staff of between 3 and 5 people, whereas larger plants of the size 20 to 40 MWe, can need as many as 20 to 40 people to properly maintain. The size of the on-site operation and maintenance staff depends on the size of the plant, the type of fuel being used, the design of the plant, the degree of automation and the operation and maintenance strategy being used (International Finance Corporation, 2017).

While process-heat driven CHP is similar to biomass-fired CHP in the general structure of the setup, there is less work to maintain and operate the system, as the problems with storing and feeding in the biomass fuel are avoided. It is therefore expected that a fairly low number of people are required to operate and maintain process heat driven CHP compared to biomass-fired CHP.

Research and development

The cogeneration technologies are very well understood and are composed of a relatively simple number of elements that are all well understood from other similar applications. These include heat exchangers, boilers, heat recovery systems, turbines and condensers. The individual parts of the machinery are all mature and well developed, and the use of them in industrial cogeneration has been applied in many industries in many different countries. While there are likely to be particularities that need to be accounted for when using the technology in any particular cement factory or similar industrial setting, the general application and system is well developed and understood, and it seems unlikely, that new breakthroughs will come in use and application of these technologies (technology development phase 4).

Investment cost estimation

The investment cost of cogeneration projects will depend heavily on size and ease of fitting them to existing machinery. It is likely to be far cheaper to include cogeneration into industrial plants from the beginning, rather than retrofit them later on.

An estimation of retrofitting an existing cement plant with cogeneration capacity, is given at $2.5 million USD per

MW (Institute for Industrial Productivity, 2014).

Examples of current projects

Biomass-fired CHP boiler:
An Khe Factory is invested by Quang Ngai Sugar Joint Stock Company, located in An Khe sugar factory in Thanh An commune, An Khe town, Gia Lai province to utilize bagasse byproducts in the sugar production process. In addition, it also takes advantage of other biomass fuel sources in the Central Highlands such as shell, coffee grounds, rice husks, sawdust, sorghum.

An Khe factory has a scale of 2 units (40 + 55) MW, officially operated from 1/2018. The plant uses stoker fired boiler technology and the steam condensate turbine (unit 55 MW has steam extraction valve fed to the degassing process). Boiler parameters: 100 bar superheated steam pressure and 540^0C superheated steam temperature. Fuel for the plant is about 600,000 tons of biomass / year, of which bagasse accounts for about 90% and other fuels account for about 10%. The electricity supplied to the power system in 2018 is 172 million kWh and in 2019 it is 147 million kWh. The total land area of the project is about 5 ha. The plant uses an electrostatic dust removal system (ESP) to reduce dust emissions.

The total investment of An Khe biomass plant was 102.8 million $ (converted to $2019, the administration, consultancy, project management, site preparation cost, the taxes and interest during construction are not included), corresponding to a nominal investment of 1.08 M$/$MW_e$. The total capital (include these components) was 103 million $, corresponding to 1.09 M$/MW. Fixed and variable O&M cost of plant is 29,000 $/MW/year and 2.9 &/MWh respectively.

Lam Son Sugar Factory address at Tho Xuan district, Thanh Hoa province, operated from 1999 which has more than 10,000 ha area of sugarcane plantation with more than 1,000 staff and workers. It has a CHP plant to make use of bagasse to generate power and with three boilers: Boiler 1&2: Q: 2x65=130 T/h, P: 32 Bar, TºC: 380; Boiler 3: Q2: 80T/h, P = 67bar, TºC: 505. Three turbines and generators: G1&G2: 2x3= 6 MW, G3=12.5 MW. Total capacity of Lam Son CHP plants is 18.5 MW with annual power production of about 50 million kWh, in which two-third generate on grid.

Process-heated CHP:
Song Lam process-heated CHP plants is a part of Song Lam Cement Factory, including 2 generator units, each with a capacity of 7MW and 4 boilers with a total steam generating capacity of 80 m^3 of steam per hour. The operation of the 4 boilers is to use exhaust fans and excess air fans to suck the excess hot air in the clinker production process through the boiler tubes to heat water, turning the water in the boiler from water into superheated steam.

The superheated steam with a pressure of about 1.3 MPa and a temperature of about 340^0 C was directed back to spin the steam turbine, the turbine will pull generators and generate electricity. The amount of hot gas carries dust when entering the boiler, the dust particles will be pressure changed and collide with the steam generating tubes, resulting in loss of kinetic energy and falling into the collection hopper, dust from the collection hopper will be returned into the production process. Thus, the waste gas and excess air after going through the residual gas power generation system will be clean of dust and cooled before being discharged into the environment. Each year this system produces about 100 million kWh, providing up to 40% of the electricity consumed by the Cement Factory.

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Data sheets

Biomass-fired co-generation in a sugar mill

Technology	**Biomass-fired cogeneration**								
US$2019	**2020**	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data				**Lower**	**Upper**	**Lower**	**Upper**		
Generating capacity for one unit (MWe)	25	25	25	4	200	4	200		1;5;12
Generating capacity for total power plant (MWe)	25	25	25	1	50	1	50		1;5
Electricity efficiency, net (%), name plate	27	27	27	20	30	20	30		1;3;7
Electricity efficiency, net (%), annual average	26	26	26	20	30	20	30	D	1;3;7
Total efficiency, net (%), name plate	85	85	85	80	90	80	90		11
Total efficiency, net (%), annual average	84	84	84	80	90	80	90		11
Forced outage (%)	7	7	7	5	9	5	9	A	1
Planned outage (weeks per year)	26	26	26	24	28	24	28	C	1
Technical lifetime (years)	25	25	25	19	31	19	31	A	8;7
Construction time (years)	2	2	2	2	3	2	3	A	7
Space requirement (1000 m^2/MWe)	35	35	35	26	44	26	44	A	1;9
Additional data for non-thermal plants									
Capacity factor (%), theoretical	-	-	-	-	-	-	-		
Capacity factor (%), incl. outages	-	-	-	-	-	-	-		
Ramping configurations									
Ramping (% per minute)	10	10	10						3
Minimum load (% of full load)	30	30	30						3
Warm start-up time (hours)	0.5	0.5	0.5						3
Cold start-up time (hours)	10	10	10						3
Environment									
PM 2.5 (mg per Nm^3)	12.5	12.5	12.5						3
SO_2 (degree of desulphuring, %)	0.0	0.0	0.0						3
NO_X (g per GJ fuel)	125	125	125						3
Financial data									
Nominal investment (M$/MWe)	1.8	1.6	1.4	1.3	2.2	1.1	1.8	B	4-8;10
- 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 ($/MWe/year)	49,500	45,500	39,600	37,100	61,900	29,700	49,500	A	4;5;8;10
Variable O&M ($/MWh)	3.2	2.9	2.5	2.4	4.0	1.9	3.2	A	5;10
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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7 IEA-ETSAP and IRENA, 2015, "Biomass for Heat and Power, Technology Brief".

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

9 India Central Electricity Authority, 2007, "Report on the Land Requirement of Thermal Power Stations".

10 Learning curve approach for the development of financial parameters.

11 Siemens, 2018: "The powerful potential of sugarcane"

Notes:

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

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

C Sugar production season is approximately half a year.

D Power efficiency is reduced by 5 %-points compared to condensing operation to reflect steam extraction at higher temperature for process heat.

CHP in a cement factory

Technology	**CHP in a cement factory**								
US$2019	**2020**	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data				**Lower**	**Upper**	**Lower**	**Upper**		
Generating capacity for one unit (MWe)	8	8	8	2	20	2	20		1,2,3
Generating capacity for total power plant (MWe)									
Electricity efficiency, net (%), name plate	18	18	18	15	25	15	25		3
Electricity efficiency, net (%), annual average									
Forced outage (%)									
Planned outage (weeks per year)									
Technical lifetime (years)									
Construction time (years)									
Space requirement (1000 m^2/MWe)									
Additional data for non-thermal plants									
Capacity factor (%), theoretical									
Capacity factor (%), incl. outages									
Ramping configuration									
Ramping (% per minute)									
Minimum load (% of full load)									
Warm start-up time (hours)									
Cold start-up time (hours)									
Environment									
PM 2.5 (mg per Nm^3)									
SO_2 (degree of desulphuring, %)									
NO_X (g per GJ fuel)									
Financial data									
Nominal investment (M$/MWe)	2.50	2.50	2.50	2.50	2.50	2.50	2.50		4
- of which equipment (%)	85	85	85	85	85	85	85	A	
- of which installation (%)	15	15	15	15	15	15	15	A	
Fixed O&M ($/MWe/year)									
Variable O&M ($/MWh)	12.50	12.50	12.50	5.00	20.00	5.00	20.00		2
Start-up costs ($/MWe/start-up)									

References:

1 Khurana, S., Banerjee, J., & Gaitonde, U. (2006). Energy balance and cogeneration for a cement plant. Appl. Therm. Eng., 2479-2489.

2 Irungu, S. N., & Muchiri, P. &. (2017). The generation of power from a cement kiln waste gases: a case study of a plant in Kenya. Energy Science & Engineering, 90-99

3 Paredes-Sánchez, J. P. (2015). Using waste energy from the Organic Rankine Cycle cogeneration in the Portland cement industry. DYNA, 15-20.

4 Institute for Industrial Productivity. (2014). Waste Heat Recovery for the Cement Sector: Market and Supplier Analysis.

Notes:

A Own estimate.

6. HYDRO POWER

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. Typically, 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.

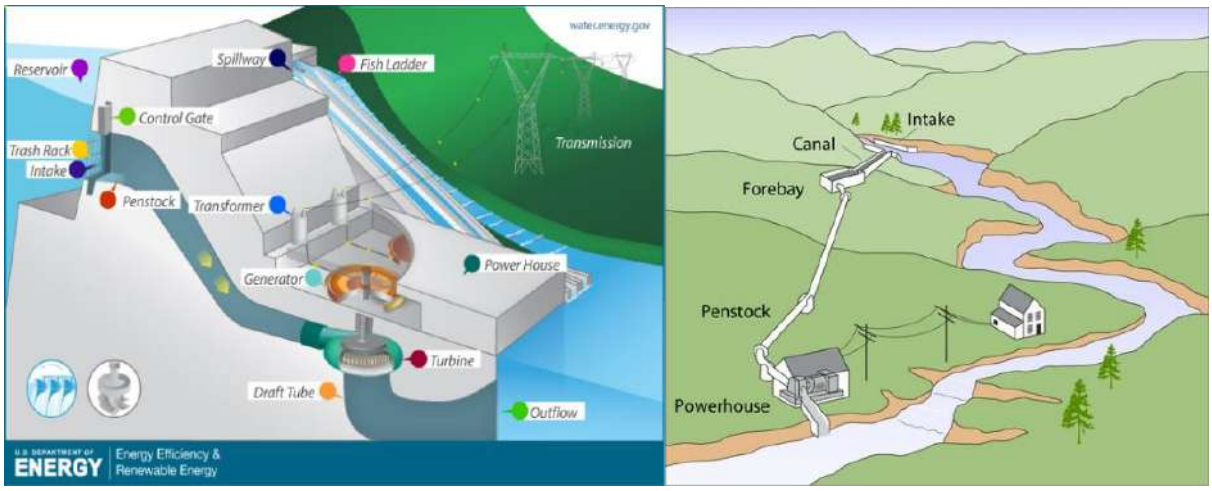


Figure 14: Reservoir and run-of-river hydropower plants (ref. 14)

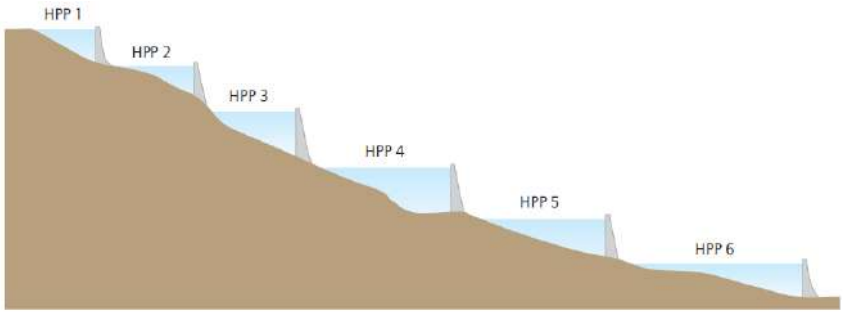


Figure 15: Cascading Systems (ref. 1)

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

Hydropower systems can have a wide range of sizes. A classification based on the size of hydropower plants is presented in table below.

Table 11: 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. Head is the change in water levels between the hydro intake and the hydro discharge point.

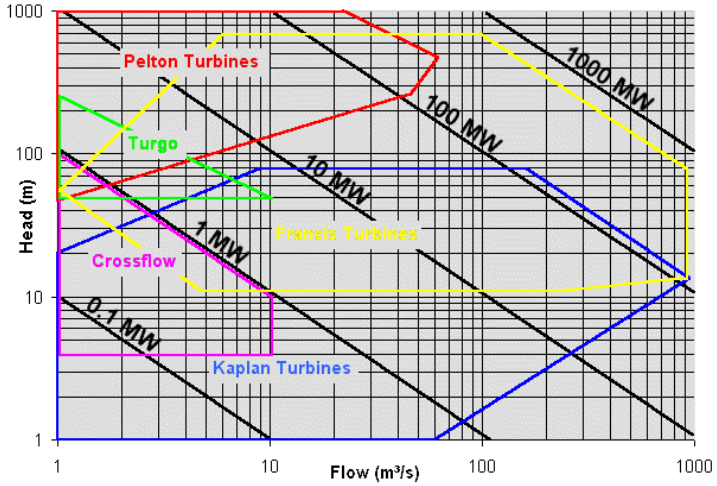


Figure 16: Hydropower turbine application chart (ref. 2)

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.

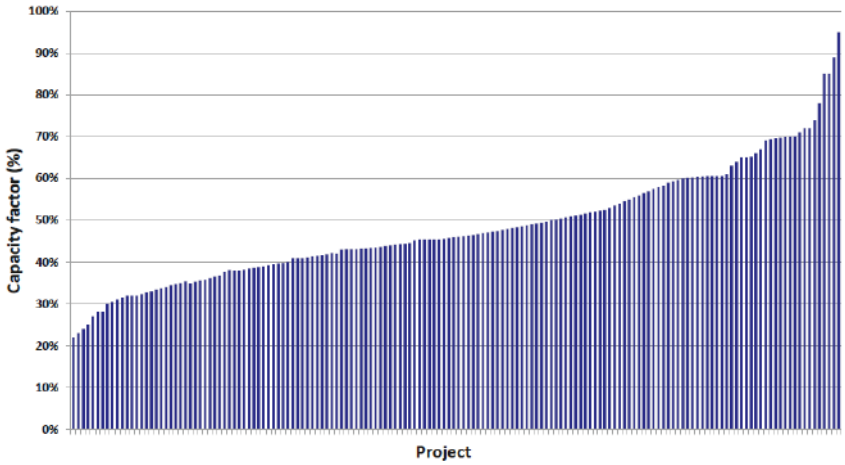


Figure 17: Capacity factors for 142 hydropower projects around the world (ref. 4)

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

Output
Electricity

Typical capacities
Hydropower systems have wide range of capacities, predominantly dependent on location and need to be assessed on a case-by-case basis. Currently a general value up to 900 MW per unit can be considered (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 its operation does not pollute or cause any emissions.
- 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 constraints.

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.
- Deforestation, resulting in more flood consequences.

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).

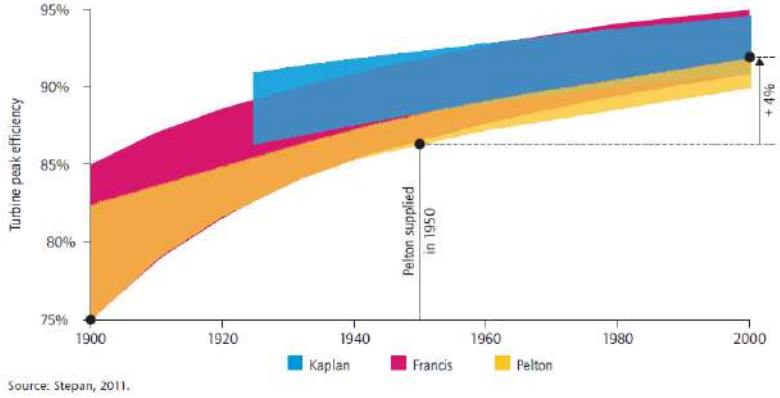


Figure 18: Improvement of hydraulic performance over time (ref. 7)

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.

Investment cost estimation

The overnight capital cost of hydropower plants strongly depends on the site where the plant is located. While hydropower benefits from economy of scale as most generation technologies, the best and most accessible sites for large hydro might be already exploited; in some cases, run of river (small size) hydro is built at a lower cost. For large hydro, data is scarce and so is the standard deviation from the average cost. Project data from IRENA shows that – on average – overnight costs for hydropower plants tend to be rather stable over the years. In fact, the technology is well-established, and the limited technological advancements might be offset by higher development costs (e.g. stricter environmental assessments). Furthermore, the capital cost for some of the existing projects like Lai Chau (large hydro) and Song Bung (small hydro) in Vietnam are much lower than international data. The new catalogue prices adjust for these factors and accounts for some inflation in costs from 2016 and 2018 as well. Also, the estimated learning rate is also considered in arriving at the final values for 2030 and 2050. The final values presented here are considering a conservative balance between international data and local data. However, it is highly recommended to take local conditions into account when estimating investment costs for hydro plants in energy planning.

Examples of current projects

Ref. 19 indicates an economic 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 an 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 1.105 billion $ ($2019, administration, consultancy, project management, site preparation cost, the taxes and interest during construction are not included), and the nominal investment was 0.93 M$/$MW_e$. The total capital (include these components) was 1.74 billion $, corresponding to 1.45 M$/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 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 38 M$ ($2019) which is equal to a nominal investment of 1.33 M$/ MW_e.

Expansion existing plant: Hoa Binh HPP expansion (ref 21)
Hoa Binh hydropower plant expansion project includes 2 units with a total capacity of 480 MW. The water intake is in Thai Thinh commune, the water tunnel and the expansion plant are 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 303 million $ ($2019, administration, consultancy, project management, site preparation cost, the taxes and interest during construction are not included), and the nominal investment was 0.63 M$/ MW_e. The total capital (include these components) was 374 million $, corresponding to 0.78 M$/MW.

Norwegian example
Many current hydro projects 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 12: 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_{2019}$/MW]	1.33	2.29	1.46	5.4

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). Because of the limited data on local cases, the investment cost estimate is somewhat uncertain. In addition, as hydro power investment costs are very dependent on the specific site, the investment will most likely vary from project to project.

Table 13: 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_{2019}$/MW]	0.93	2.08	0.62	8.32

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 14: Investment costs in international studies

IRENA (2018) (M$$_{2019}$/MW)	2017	
All sizes	1.6	
ASEAN (2016) (M$$_{2019}$/MW)	Historical	
Small hydro (23 projects, average capacity: 8.5 MW)	0.88	
TC (2017) (M$$_{2019}$/MW)	2030	2050
Indonesian (small)	2.28	2.28
Indonesian (large)	2.08	2.08

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 into 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 2019.

Technology	Hydro power plant - Small system								
US$2019	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$19/MWe)	1.75	1.75	1.75	0.8	4.0	0.8	4.0	C;D	4;5;6;7
- of which equipment (%)	30	30	30	20	50	20	50		7
- of which installation (%)	70	70	70	50	80	50	80		7
Fixed O&M ($/MWe/year)	41,900	39,800	37,300	22,000	41,900	22,000	41,900		4;5;7
Variable O&M ($19/MWh)	0.50	0.48	0.45	0.38	0.63	0.33	0.56	B	1
Start-up costs ($19/MWe/start-up)	-	-	-	-	-	-	-		
Technology specific data									
Size of reservoir (MWh)									

References:

1 Stepan, 2011, Workshop on Rehabilitation of Hydropower, “The 3-Phase Approach”.

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

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Notes:

A This is the efficiency of the utilization of the water’s potential energy. This cannot be compared with a thermal power plant that have to pay for its fuel.

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

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

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

Technology	Hydro power plant - large system								
US$2019	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$19/MWe)	1.5	1.5	1.5	0.6	8.0	0.6	8.0	D;E	1;4;5;6;9
- of which equipment (%)	30	30	30	20	50	20	50		11
- of which installation (%)	70	70	70	50	80	50	80		11
Fixed O&M ($/MWe/year)	37,700	35,800	33,600	28,300	47,100	25,200	42,000	C	1;4;5;6
Variable O&M ($19/MWh)	0.65	0.62	0.58	0.49	0.81	0.43	0.72	C	1;5
Start-up costs ($19/MWe/start-up)	-	-	-	-	-	-	-		

References:

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5 Learning curve approach for the development of financial parameters.

6 IEA, Projected Costs of Generating Electricity, 2015.

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

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

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

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

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

Notes:

A This is the efficiency of the utilization of the water’s potential energy. This cannot be compared with a thermal power plant that have to pay for its fuel.

B Hydro power plants can have a very long lifetime is operated and maintained properly. Hoover 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 be equalized because the best locations will be utilized first. The investment largely depends on civil work.

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

7. SOLAR PHOTOVOLTAICS

Brief technology description

Solar energy converts energy from sunlight to electricity with the help of photovoltaic panels consisting of solar cells. A solar cell is a semiconductor component that generates electricity when exposed to solar irradiation. For practical reasons, several solar cells are typically interconnected and laminated to (or deposited on) a glass pane in order to obtain a mechanical ridged and weathering protected solar module. The photovoltaic (PV) modules are typically 1-2.5 m^2 in size and have a power density in the range 160-500 Watt-peak pr. m^2 (Wp/m^2). They are sold with a product warranty of typically ten to twelve years, a power warranty of minimum 25 years and an expected lifetime of more than 30-35 years depending on the type of cells and encapsulation method.

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

- Crystalline silicon (c-Si); the most widely used substrate material is made from purified solar grade silicon and comes in the form of mono- or multi-crystalline silicon wafers. Currently more than 95 pct. of all PV modules are wafer-based divided between multi- and mono-crystalline. This technology platform is expected to dominate the world market for decades due to significant cost and performance advantages (ref. 1).
- Passivated Emitter and Rear Cell (PERC); this a more recent advancement in solar cell technology where monocrystalline silicon cell architecture is modified to have a passivation layer at the back of the cells. The additional layer allows for the solar radiation, that has not been absorbed, to reflect and allow for a second attempt for absorption by the cell. This layer improves the cell efficiency and reduces cell heating. (ref. 18)
- Tandem/hybrid cells; Tandem solar cells are stacks of individual cells, one on top of the other, that each selectively convert a specific band of light into electrical energy, leaving the remaining light to be absorbed and converted to electricity in the cell below. (ref. 18)
- Thin film solar cells; where the absorber can be an amorphous/microcrystalline layer of silicon (a-Si/µc-Si), Cadmium telluride (CdTe) or Copper Indium Gallium (di)Selenide (CIGS). These semiconductor materials are deposited on the top cover glass of the solar module in a micrometre thin layer. Tandem junction and triple junction thin film modules are commercially available. In these modules several layers are deposited on top of each other to increase the efficiency (ref. 1).
- Monolithic III-V solar cells; that are made from compounds of group III and group V elements (Ga, As, In and P), often deposited on a Ge substrate. These materials can be used to manufacture highly efficient multi-junction solar cells that are mainly used for space applications or in Concentrated Photovoltaic (CPV) systems (ref. 1).
- Perovskite material PV cells; Perovskite solar cells are in principle a Dye Sensitized solar cell with an organo-metal salt applied as the absorber material. Perovskites can also be used as an absorber in modified (hybrid) organic/polymer solar cells. The potential to apply perovskite solar cells in a multi-stacked cell on e.g. a traditional c-Si device provides interesting opportunities (ref. 1).

One of the emerging trends in the solar PV space is innovative advancements of PV module technologies (ref.18):

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

In addition to PV modules, a grid connected PV system also includes Balance of System (BOS) consisting of a mounting system, dc-to-ac inverter(s), cables, combiner boxes, optimizers, monitoring/surveillance equipment and for larger PV power plants also transformer(-s). The PV module itself accounts for less than 50% of the total system costs (and this share is dropping fast), inverters around 5-10%.

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

share of distributed and off-grid PV (rooftop and industrial PV) is rising.

Rooftop PV
A rooftop photovoltaic power station, or rooftop PV system, is a photovoltaic system that has its electricity-generating solar panels mounted on the rooftop of a residential or commercial building or structure. Rooftop-mounted systems are small compared to ground-mounted photovoltaic power stations (utility-scale PV) with capacities in the kilowatt range.

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

Off-grid systems must be equipped with energy storage system like battery since the system is not connected to the grid. When the power generated by the rooftop is not used, the excess power will charge the battery until full. The battery power will be used later on when there is no sun or when the electricity supply from the rooftop is intermittent due to an external factor like cloud cover or the like.

Vietnam had mechanism to encourage the development of solar power in Vietnam: Decision No. 11/2017/QD-TTg dated April 11, 2017 and Decision No. 13/2020/QD-TTg dated April 6, 2020 of the Prime Minister. According to statistics of Vietnam Electricity, up to July 2020 there were more than 42,000 rooftop solar projects with the total installed capacity of 926 MWp coming into operation. By the end of 2020, the total capacity of rooftop PV power plants coming into operation has reached nearly 9700 MWp.

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

The average annual solar energy received on a horizontal surface (Global Horizontal Irradiance, GHI) in Vietnam varies between approx. 1200 kWh and 2000 kWh per m^2. See figure below.

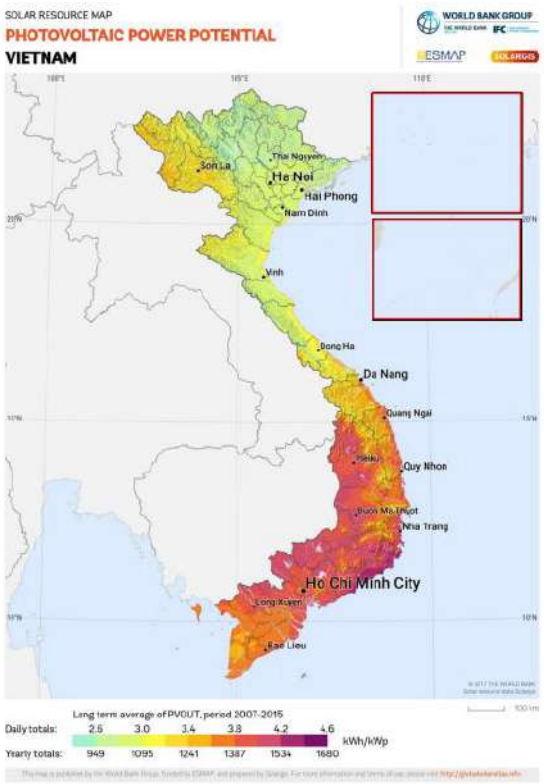


Figure 19: Full load hours (kWh/kW_p) for PV in Vietnam.[12] Ref 7.

[12] Paracel and Spratly islands represented in the red boxes in the figure.

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 19%. 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 needs to be around 11° in average. Since land cost among others also plays a role in the total business case of a solar plant, the optimal tilt angle (and its effect on shadow casting and corresponding dependency for row spacing) may vary slightly depending on the project.

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 cell 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. Actual patterns may vary from the below example and depending on the season.

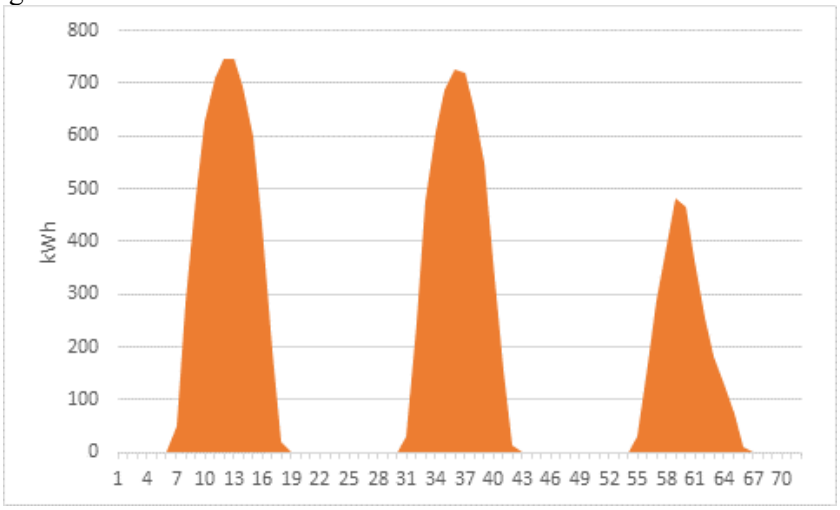


Figure 20: Generation for three days in Central Vietnam. From: www.renewables.ninja

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.

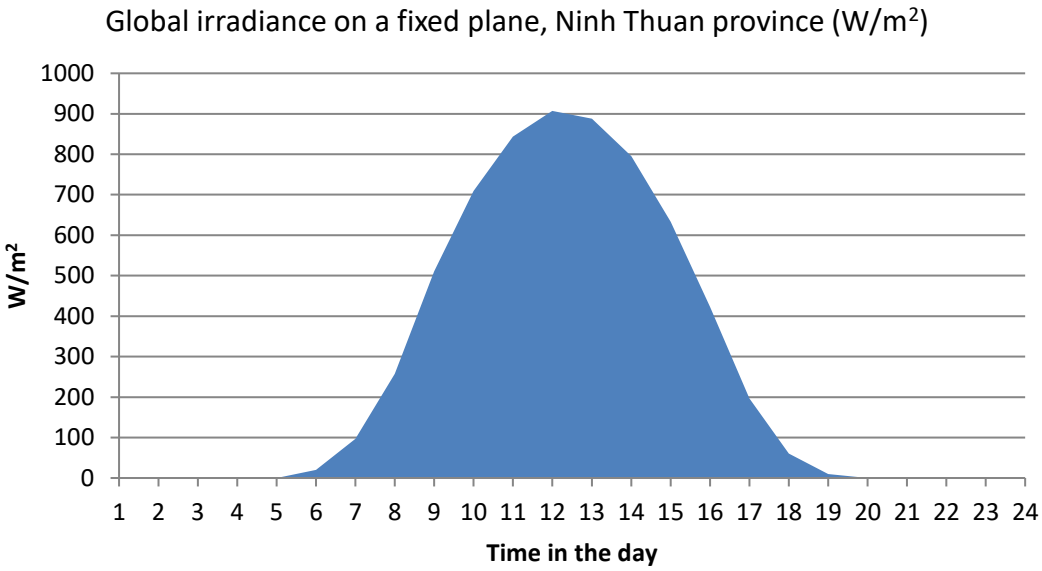


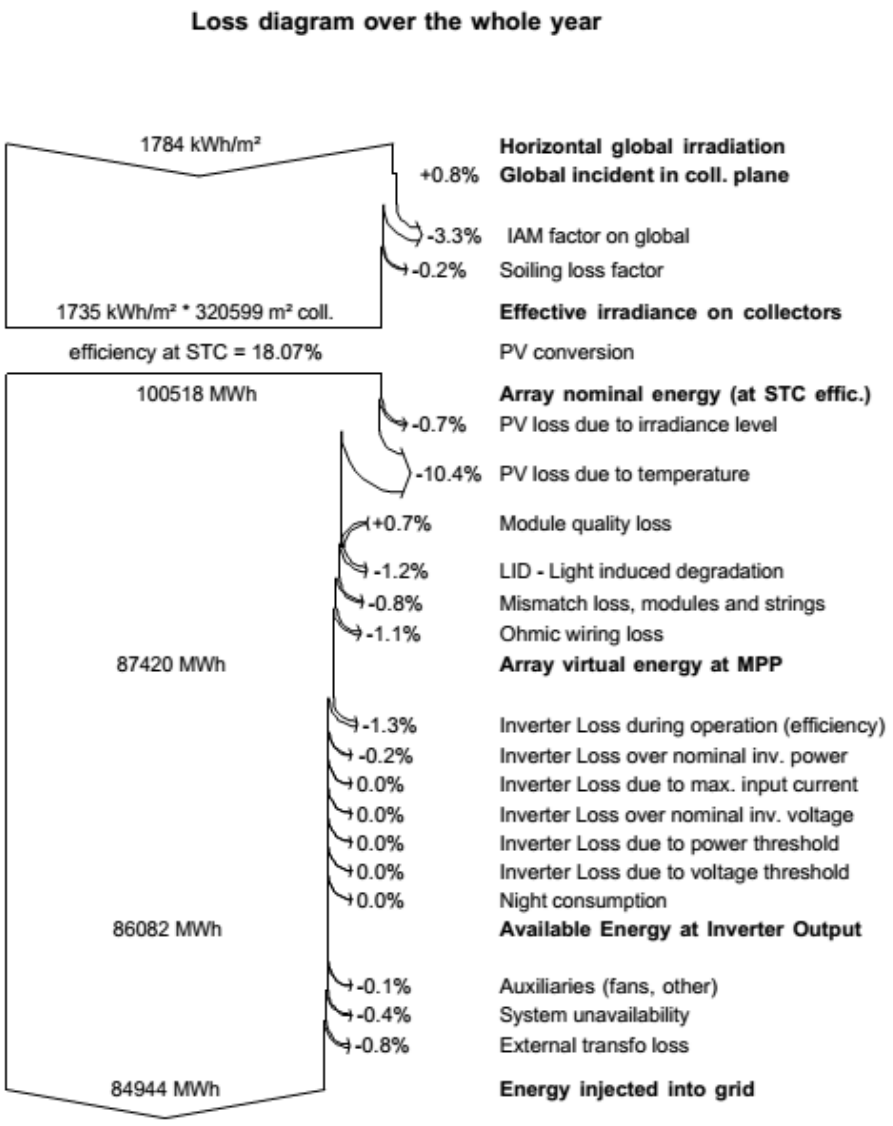
Figure 21: Global irradiance on a fixed plane (W/m^2) during the course of the day in the Ninh Thuan; average daily profile for September, the month with the best solar conditions. Source: Pvsyst Meteo data.

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 E_{PV} [kWh] from a PV installation can be calculated as follows: with a peak capacity P_p and surface area A can be calculated as follows:

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

Where:
A [m^2] is the modules area
GHI [kWh/m^2] is the Global Horizontal Irradiation at the location
η_{pre} [%] represents pre-conversion losses (for shading, dirt etc.)
η_{nom} [%] is the module nominal efficiency as specified by the manufacturer, in standard operating conditions
η_{rel} [%] is the module relative efficiency, corrected for the ambient temperature
η_{sys} [%] is the system efficiency, i.e. all losses incurred in cables, electronic components and plant layout.



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

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

Wear and degradation

In general, a PV installation is very robust and only requires a minimum of maintenance and component replacement over the course of its lifetime. The inverter typically needs to be replaced every 10-15 years. For the PV module, only limited physical degradation of a c-Si solar cell will occur. It is common to assign a constant yearly degradation rate of 0.25-0.5% per year to the overall production output of the installation. This degradation rate does not represent an actual physical mechanism. It rather reflects general failure rates following ordinary reliability theory with an initial high (compared to later) but rapidly decreasing "infant mortality", followed by a low rate of constant failures and with an increasing failure rate towards the end-of-life of the various products (ref. 13). Failures in the PV system is typical relate to soldering, cell crack or hot spots, yellowing or delamination of the encapsulant foil, junction box failures, loose cables, hailstorm and lightning (ref. 13).

Efficiency and area requirements

The efficiency of a solar module, η_{mod}, expresses the fraction of the power in the received solar irradiation that can be converted to useful electricity. A typical value for commercially available PV modules today is 15 – 20%, when measured at standard test conditions. The module area needed to deliver 1 kWp of peak generation capacity can be calculated as $1 / \eta_{mod}$ on a first approximation and equals 6.25 m^2 by today's standard PV modules.

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 area 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) indicates 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 in Vietnam 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).*

Typical capacities

Typical capacities for PV systems are available from watt 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 200-500 Wp. The inverter sizing is dependent on the sizing factor i.e. DC/AC ratio. Based on the local case data available this ratio is 1.2÷1.25 for Vietnam.

Rooftop solar PV installations are usually <100 kW capacity. Commercial or Industrial PV systems are typically installed on industries, offices or public buildings, and range typically from 50 to 500 kW in size. Such systems are often designed to the available roof area and for a high self-consumption. Utility scale systems or grid-connected PV power plants will normally be ground mounted and typically range in size from 1 MW to more than 100 MW. They are often operated by independent power producers that by use of transformers deliver electricity to the medium or high voltage grid depending on the capacity size. The figure below shows the distribution of rooftop solar installed capacity by customer group in Vietnam. (ref. 19)

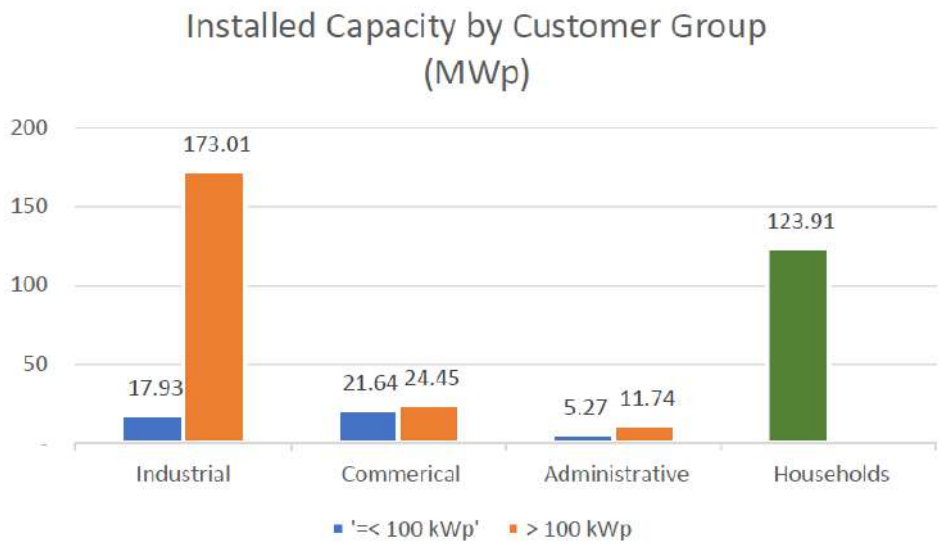


Figure 22: *Rooftop solar installed capacity by customer group in Vietnam (ref. 19)*

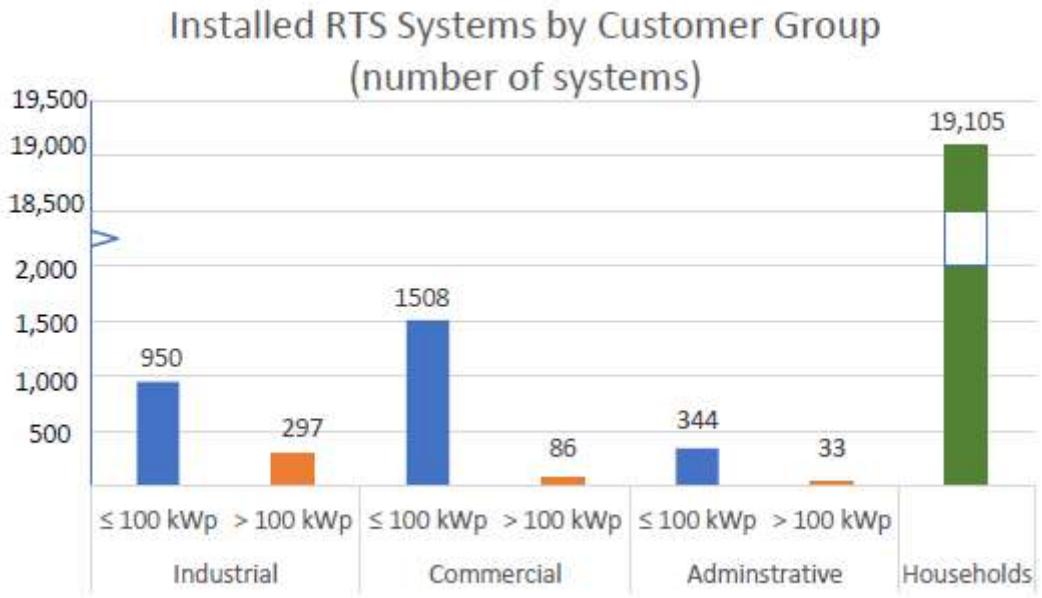


Figure 23: Rooftop solar number of projects by customer group in Vietnam (ref. 19)

Ramping configurations and other power system services

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

Advantages/disadvantages

Advantages:

- PV does not use any fuel or other consumable.
- PV is noiseless (except for fan-noise from inverters and transformers).
- 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 modules have a long lifetime of more than 30 years and PV modules can be recycled.
- PV systems are modular and easy to install.
- Operation & Maintenance (O&M) of PV plants is simple and limited as there are no moving parts and no wear and tear, with the exception of tracker systems. Inverters only need be replaced once or twice during the operational life of the installation in average.
- 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, making financing cost more decisive, and a low-capacity factor compared to other generation technologies.
- Mono- and poly-crystalline panels (most used) only produce power when there is direct sunlight. Moreover, this creates a requirement for storage to support power regulation.
- 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 (since production capacity is not held back during generation).

- Materials abundancy (In, Ga, Te) is of concern for large-scale deployment of some thin-film technologies (CIGS, CdTe), which have a minor share of the total market.
- Some thin-film technologies do contain small amounts of cadmium and arsenic.
- The best perovskite absorbers contain soluble organic lead compounds, which are toxic and environmentally hazardous at a level that calls for extraordinary precautions.

Environment

The energy payback time of a typical crystalline silicon PV system in Southern Europe is 1.25 years. Energy payback is the period of time for which a solar PV plant needs to be in operation before it has generated as much electricity as it consumes in its lifecycle.

The environmental impacts from manufacturing, installing and operating PV systems are limited. The main materials used to produce PV panels include glass, plastic, aluminium, silicon and various metals in small quantities. The breakdown of the main materials in the two most common types of modules (crystalline silicon and thin film) can be visualised in the image below. Furthermore, the modules may contain small amounts of lead and thin film modules especially, may contain small amounts of cadmium and arsenic.

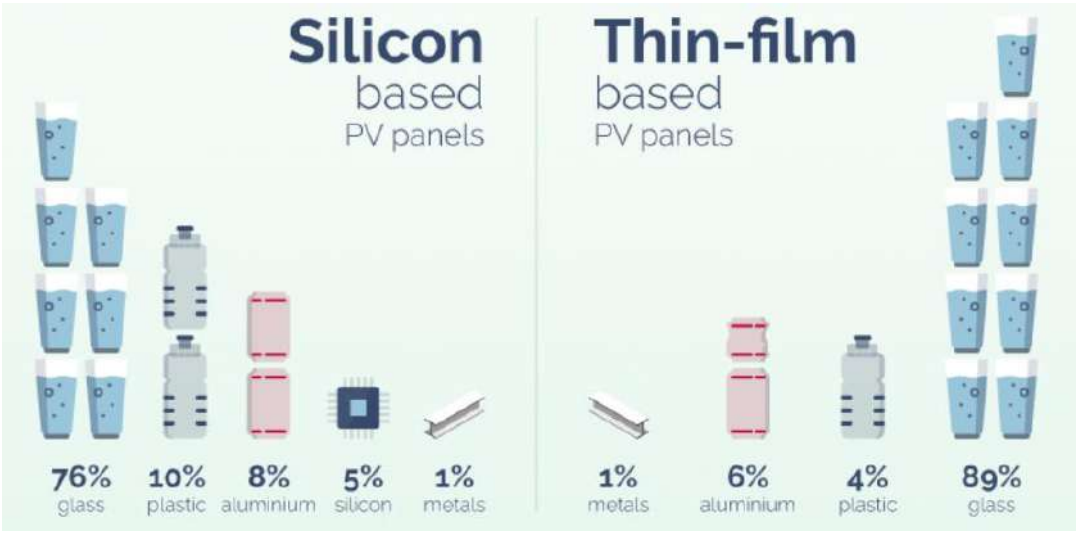


Figure 24: Main materials in a silicon based and thin film solar PV panel. (ref. 22)

With the increasing installations of PV panels, their end-of-life treatment and waste management are increasingly important topics of discussion. According to a study by IRENA, reduction of wastes can begin at the manufacturing stage itself, where it is shown that, driven by research on the PV components, material savings and panel efficiencies will drive a reduction in materials use per unit of power and the use of potentially hazardous substances (see Figure 25 below) (ref. 23). Additionally, improved panel quality would also lead to a reduction of failures and therefore creation of waste during the lifetime.

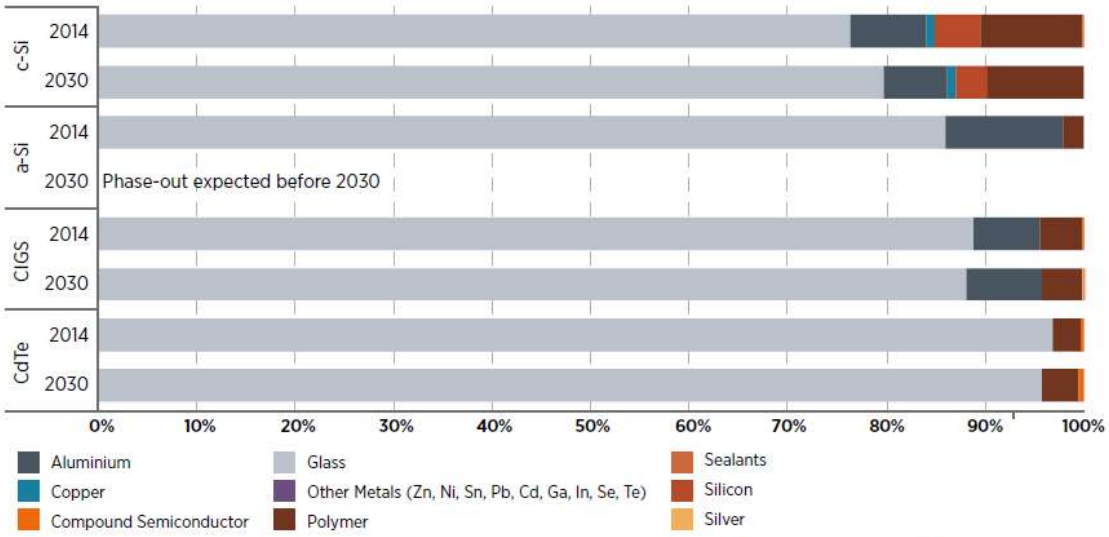


Figure 25: Evolution to 2030 of materials used for different PV panel technologies as a percentage of total panel mass (ref. 23)

As for the end of life of the panels, it is estimated that ~96% of the materials can either be reused or recycled with proper treatment. (ref. 22) The different types of processes are represented in the flow chart shown in Figure 26. Furthermore, a study estimated that using the "Full Recovery End of Life Photovoltaic project" (FRELP) method, the private cost of end-of-life management of the crystalline silicon PV module is USD 6.7/m2 and much of this cost is from transporting (USD 3.3/m2), while the actual recycling process (the cost of consumed materials, electricity or the investment for the recycling facilities) is very small (USD 0.3/m2). Further, it was found that the external cost of PV end of life management is very similar to the private cost (USD 5.2/m2). It estimated that the total economic value of the recycled materials from c-Si PV waste is USD 13.6/m2. This means that when externality costs are not considered, the net benefit of recycling is USD 6.7; when the externality cost of recycling is considered, there is still a net benefit of USD 1.19 per m2. (ref. 25) While this are just estimated costs, they give a representative indication as to the feasibility of reuse and recycle of materials from PV panels. Moreover, the revenues from second-life or reused products also needs to be considered.

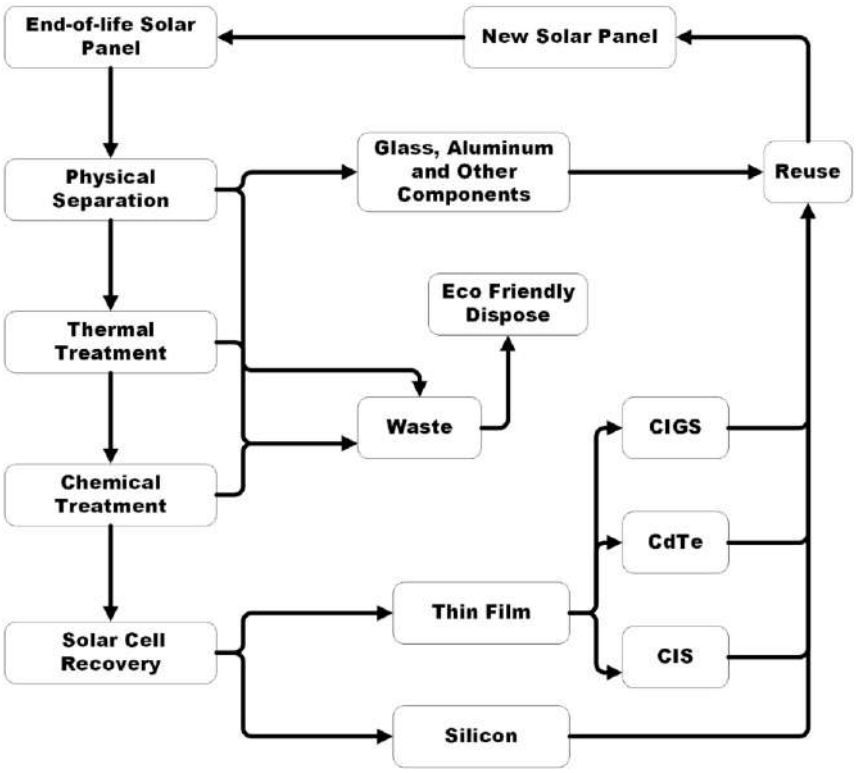


Figure 26: Different types of solar PV recycling processes. (ref. 24)

While there is continuous research ongoing in this area, and an increasing need for deployment of end-of-life management solutions, a major catalyst to the process would be to establish strong regulatory requirements. As of now, despite a significant discussion among organisations across the globe, about waste management from solar plants, only the European Union's WEEE directive, provides a regulatory framework whereby appropriate treatment of the waste streams is promoted. According to the WEEE directives all electrical or electronic product manufacturers are legally accountable for proper waste management of the product no matter where the manufacturing facility is located. The WEEE directive has detailed guidelines that includes collection, recovery, recycling along with environment and public health safety. (ref. 26) While other countries may have some regulations regarding e-waste in general, what makes the WEEE significant is inclusion of PV module waste streams as part of this framework. Considering the recent boom of the solar PV instalments, going forward it is of critical importance that countries, like Vietnam, promote the setting up end of life management infrastructure for solar PV waste, and support it through a regulatory framework.

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. Vietnam and Thailand are market leaders in solar panel manufacturing in SE Asia.

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

Investment cost estimation
The cost of solar PV projects has decreased significantly. The reported investment cost of the Vietnamese solar PV power plants ranges from 0.87 to 0.97 million USD/MW. The investment cost of rooftop solar PV in Vietnam is a little higher than ground mounted PV and this ranges from 0.82 to 1.13 million USD/MW. Ground-mounted utility scale solar plants usually are cheaper than rooftop plants primarily due to economies of scale, and better possibilities for optimizing the plant design.

Module prices can be observed at the PV Insights website. By September 2020, the average price of poly silicon solar modules, that are slightly less efficient than mono silicon modules, was 0.167 USD/Watt, with prices as low as 0.15 USD/Watt. The price of PV module in Vietnam ranges from ~0.2 to 0.3 USD/Watt. (ref. 20)

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

For this assessment it is proposed applying a learning rate of 20% for approx. two-thirds of the solar PV system price, which relates to the module and the inverter. This is slightly lower than the historical observed values, but still a high learning rate compared to other technologies. Using a learning rate of 20% for the module and a future deployment of solar PV capacity as projected by the IEA, we expect PV module costs to drop by around 20-30% between 2020 and 2030 and between 40 and 50% between 2020 and 2050 (ref. 21). An explanation of the learning rate approach is provided in the appendix, if needed.

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

The investment cost of a solar PV project is subject to uncertainty, especially because the technology is capital intensive. The size of the project also contributes to the specific cost, as small projects tend to require higher specific investments per capacity installed. The table below summarizes investment cost figures from relevant sources,

along with the recommended values (ground-mounted PV). The solar PV industry has notched up the competitiveness of manufacturing processes in recent years, driven by a considerable R&D spending on cell materials and modules design. Future costs for solar PV in Vietnam will depend on local content rules, import duties and the rise of a competitive manufacturing industry in the country; cost reductions will also be achieved through more solid experience in the project development and installation stages. As of 2020, there is a cost gap between local and international prices. This catalogue expects this gap to narrow with time, leading to a convergence with international prices in the long run.

The investment costs of other types of PV plants (industrial, rooftop, floating – not reported here) tend to be higher than those of ground-mounted PV due to economy of scale.

Investment costs [MUSD$_{2019}$/MW]		**2018-19**	**2020**	**2030**	**2050**
Catalogues	**New Catalogue (2021)**		**0.93**	**0.66**	**0.48**
	Existing Catalogue (2019)		1.10	0.84	0.65
Vietnamese data	Project: Xuan Thien Thuan Bac		0.97		
	Project: Phuoc Ninh		0.94		
	Project: Solar Farm Nhon Hai		0.92		
	Project: Trung Nam		0.90		
	Project: Se San 4		0.92		
	Project: Thien Tan 1.2		0.87		
International data	IEA WEO 2019 (average of India and China)	0.84			0.46 *(2040)*
	Danish technology catalogue		0.48	0.34	0.27
	NREL ATB	1.17	0.99	0.61	0.50
	Lazard	1.00			
	UK Government (DECC)			0.58	0.45 (2040)
Projection	Learning curve – cost trend [%]	-	100%	71%	52%

Examples of current projects

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

The Bau Ngu lake PV plant is 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 operated in July 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 using 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 will be 57.98 M$ ($2019, the administration, consultancy, project management, site preparation cost, the taxes and interest during construction are not included), equal the nominal investment of 0.94 $M\$_{2019}/MW_p$ and 1.14 $M\$_{2019}/MW_{ac}$. The total capital (including these components) is 69.8 M$, corresponding to 1.12 $M\$_{2019}/MW_p$.

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 operated 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 45.97 M$ ($2019, the administration, consultancy, project management, site preparation cost, the taxes and interest during construction are not included), equal the nominal investment is 0.9 $M\$_{2019}/MW_p$. The total capital (include these components) is 56 M$, corresponding to 1.12 $M\$_{2016}/MW_p$.

Update large scale PV: Xuan Thien Thuan Bac PV plant (Ref. 15)

Xuan Thien Thuan Bac PV plant is located in Thuan Bac district, Ninh Thuan province with total installed capacity of 256 MWp and the actual capacity output delivered to the grid will be 200 MWac, the plant was put into operation in February 2020.The plant is using fixed tilted plane with the tilt angle is 12^0 and the azimuth is 180^0. The plant

uses PV module type poly-crystalline silicon (poly c-Si) with 330 Wp panel. The total number of panels used will be 727,200, divided into 80 blocks, each block uses an inverter 2.5 MVA. The efficiency of PV panel is 16.63%, the maximum efficiency of the inverter used is 99% (the EURO and CEC efficiency are 98.8% and 98.97% respectively). The total land used by Xuan Thien Thuan Bac will be about 259 ha, corresponding to 10.1 m^2/kWp. The total investment is 206.96 M$ ($2019, the administration, consultancy, project management, site preparation cost, the taxes and interest during construction are not included), and the nominal investment is 0.83 $M\$_{2019}/MW_p$ and 1.03 $M\$_{2019}/MW_{ac}$. The total capital (include these components) is 255.84 M$, corresponding to 0.99 $M\$_{2019}/MW_p$.

Update large scale PV: Trung Nam PV plant – 450 MW (Ref.15)
The Trung Nam PV solar photovoltaic plant located in Thuan Nam district, Ninh Thuan province with a grid capacity of 450 MW_{ac}, was the largest PV power plant of Vietnam and Southeast Asia. After 102 days of urgent construction, the plant has been inaugurated on October 12, 2020. The fixed tilted plane technology is used with an angle of 11^0 and the azimuth is 180^0. The plant uses more than 1,400,000 mono-cell PV panel type 455 W_p and 460 Wp, dividing in to 102 blocks, each block use 1 inverter 4560 kVA to convert DC to AC power. The efficiency of the PV panel at Standard Test Condition is more than 20 %. The land area occupied by the project is about 557 ha corresponding to 9.9 m^2/kWp. The total investment is 431.8 M$ ($2019, the administration, consultancy, project management, site preparation cost, the taxes and interest during construction are not included), and the nominal investment is 0.79 $M\$_{2019}/MW_p$ and 0.96 $M\$_{2019}/MW_{ac}$. The total capital (including these components) is 526.66 M$, corresponding to 0.94 $M\$_{2019}/MW_p$.

Rooftop PV: EVN building rooftop PV
The rooftop PV system in EVN building (Ba Dinh district, Ha Noi) has a total capacity of 19,84 kW_p and it took 45 days from August to September 2017 to deploy. The system consists of 64 PV panels 310 W_p with a total 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 the system was 22,880 $, corresponding to 1.14 $M\$_{2019}/MW_{ac}$.

Updated project: Rooftop PV:

The rooftop PV solar system in District 9, Ho Chi Minh city with a capacity of 10.08 kWp, provided and installed by Vu Phong solar in September 2020. The project used 28 panels of LG mono type 360 Wp and inverter 10kW of AEC with 2 of MPPT. The installed area is 65 m^2 corresponding to 0.65 ha/MWe. The total investment cost is 10348 $\$_{2019}$, and the nominal investment is 1.03 $M\$_{2019}$/MWac.



PV solar rooftop in District 9, Ho Chi Minh city (10.08 kWp)

The rooftop PV solar system in Dak Nong province with capacity of 135 kWp, provided and installed by Giva solar in September 2020. The project used 311 panels of Canadian mono type 435 Wp and 1 of 50kW inverter and 2 of 36 kW inverter type Sofar Solar. The installed area is 700 m2 corresponding to 0.57 ha/MWe. The total investment cost is 103,552 $\$_{2019}$, equal the nominal investment is 0.85 $M\$_{2019}$/MWac.



PV solar rooftop in Dak Nong province (135 kWp)

The rooftop PV solar system in Long Bien district, Ha Noi city with capacity of 5.28 kWp, provided and installed by Free solar in May 2020. The project used 16 panels of Qcell mono type 330 Wp and 1 of SMA 5 kW inverter. The installed area is 36 m2 corresponding to 0.68 ha/MWe. The total investment cost is 5000 $\$_{2019}$, and the nominal investment is 0.99 M$\$_{2019}$/MWac.

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".*

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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 2019. The *uncertainty* is related to the specific parameters and cannot be read vertically – meaning a product with e.g. lower efficiency does not have a lower price.

Technology	**Utility-scale Solar PV**								
US$2019	**2020**	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data				**Lower**	**Upper**	**Lower**	**Upper**		
Generating capacity, a typical power plant (MWe)	50	50	50					C	1
Electricity efficiency, net (%), name plate	-	-	-					A	
Electricity efficiency, net (%), annual average	-	-	-					A	
Forced outage (%)	-	-	-						
Planned outage (weeks per year)	-	-	-						
Technical lifetime (years)	35	40	40	25	40	35	45		1,6
Construction time (years)	0.7	0.5	0.5	0.3	1	0.25	1		5
Space requirement (1000 m^2/MWp)	11	11	11	10	11	10	11		5
Additional data for non-thermal plants									
Capacity factor (%), theoretical	21	24	24	14	23	14	24		1,2
Capacity factor (%), incl. outages	21	24	24	14	23	14	24		1,2
Ramping configurations									
Ramping (% per minute)	-	-	-	-	-	-	-	B	
Minimum load (% of full load)	-	-	-	-	-	-	-	B	
Warm start-up time (hours)	-	-	-	-	-	-	-	B	
Cold start-up time (hours)	-	-	-	-	-	-	-	B	
Environment									
PM 2.5 (gram per Nm^3)	0	0	0						
SO_2 (degree of desulphuring, %)	0	0	0						
NO_X (g per GJ fuel)	0	0	0						
CH_4 (g per GJ fuel)	0	0	0						
N_2O (g per GJ fuel)	0	0	0						
Financial data									
Nominal investment (M$/MWe)	0.93	0.66	0.48	0.87	0.97	0.31	0.71	D,R,S	1,3,4,5
- of which equipment	39%	36%	25%						
- of which installation	61%	64%	75%						
Fixed O&M ($/MWe/year)	15,500	10,000	8,000	11,600	19,400	5,300	10,700	E,Q	1,6
Variable O&M ($/MWh)	0	0	0						
Start-up costs ($/MWe/start-up)	0	0	0						
Technology specific data									
Global horizontal irradiance (kWh/m2/y)	1,600	1,600	1,600	1,200	1,900	1,200	1,900	F	8
DC/AC sizing factor (Wp/W)	1.20	1.20	1.20					G	5
Transposition Factor for fixed tilt system	1.01	1.01	1.01					H	8
Performance ratio [-]	0.84	0.87	0.90					I	6
PV module conversion efficiency (%)	20.0%	23.0%	26.0%						6
Inverter lifetime (years)	15	15	15						6
Output									
Full load hours (kWh/kW)	1,600	1,700	1,750					J, L, T	
Peak power full load hours (kWh/kWp)	1,350	1,400	1,450					K, L	
Financial data									
PV module & inverter cost ($/Wp)	0.30	0.20	0.10						7
Balance of Plant cost ($/Wp)	0.48	0.35	0.30						7
Specific investment, total system ($/Wp)	0.78	0.55	0.40					M	5,6,9
Specific investment, total system (M$/MW)	0.93	0.66	0.48					P	

Technology	Rooftop PV grid connected								
US$2019	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for total power plant (kW)	10	10	10					C	1,5,6
Electricity efficiency, net (%), name plate	-	-	-					A	
Electricity efficiency, net (%), annual average	-	-	-					A	
Forced outage (%)	-	-	-						
Planned outage (weeks per year)	-	-	-						
Technical lifetime (years)	35	40	40	25	40	35	45		1,6
Construction time (years)	0.08	0.08	0.08	0.01	0.13	0.01	0.13		5
Space requirement (m^2/kW)	6.5	6	5	5	8	5	6		1,5
Additional data for non-thermal plants									
Capacity factor (%), theoretical	15.4	16.0	16.6	14	23	14	24		1,2
Capacity factor (%), incl. outages	15.4	16.0	16.6	14	23	14	24		1,2
Ramping configurations									
Ramping (% per minute)	-	-	-	-	-	-	-	B	
Minimum load (% of full load)	-	-	-	-	-	-	-	B	
Warm start-up time (hours)	-	-	-	-	-	-	-	B	
Cold start-up time (hours)	-	-	-	-	-	-	-	B	
Environment									
PM 2.5 (gram per Nm^3)	0	0	0						
SO_2 (degree of desulphuring, %)	0	0	0						
NO_X (g per GJ fuel)	0	0	0						
CH_4 (g per GJ fuel)	0	0	0						
N_2O (g per GJ fuel)	0	0	0						
Financial data									
Nominal investment (M$/MWe)	1.00	0.71	0.52	1.45	1.60	0.50	1.20	D,R,S	3,4,5
- of which equipment	40%	40%	39%						
- of which installation	60%	60%	61%						
Fixed O&M ($/MWe/year)	14,800	10,000	8,000	11,100	18,500	5,300	10,700	E,Q	6
Variable O&M ($/MWh)	0	0	0	0	0	0	0		
Start-up costs ($/MWe/start-up)	0	0	0	0	0	0	0		
Technology specific data									
Global horizontal irradiance (kWh/m2/y)	1,600	1,600	1,600	1,200	1,900	1,200	1,900	F	8
DC/AC sizing factor (Wp/W)	1.05	1.05	1.05					G	5
Transposition Factor for fixed tilt system	1.01	1.01	1.01					H	8
Performance ratio	0.84	0.87	0.90					I	6
PV module conversion efficiency (%)	20.0%	23.0%	26.0%						6
Inverter lifetime (years)	15	15	15						6
Output									
Full load hours (kWh/kW)	1,400	1,450	1,500					J, L, T	
Peak power full load hours (kWh/kWp)	1,350	1,400	1,450					K, L	
Financial data									
PV module & inverter cost ($/Wp)	0.4	0.3	0.2						7
Balance of Plant cost ($/Wp)	0.80	0.56	0.47						7
Specific investment, total system ($/Wp)	0.99	0.70	0.51					M	5,6,9
Specific investment, total system (million $/MW)	1.00	0.71	0.52					P	

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Notes:

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

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

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

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

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

F The global horizontal irradiation is a measure of the energy resource potential available and depends on the exact geographical location.

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

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

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

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

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

L Capacity factor = Full load hours / 8760.

M Current international market prices for utility scale PV systems have been estimated based on interviews with Danish developers and an 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 inverter (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 inverter accounts for decreases over time as the result of the higher learning rate compared to the balance of plant. Vietnamese prices are assumed to be somewhat higher in the first years thereafter approaching gradually the international level.

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

Q The cost of O&M includes insurance and regular replacement of inverters and land-lease. Annual O&M is estimated to be 2 % of investment cost per MWp.

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

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

T Full load hours: Total hours in a year where the plant produces power at rated capacity.

8. WIND POWER

Brief technology description

Wind power has become a widespread renewable energy source in the past decades, given the significant improvements in efficiency, the development of structured manufacturing and supply chains, and the overall technological reliability.

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

- Onshore wind
- Offshore wind

Circular No.39/2018/QD-TTg dated 10/9/2018 about incentive mechanism for developing wind power in Vietnam defining onshore and offshore wind projects are projects that have wind turbines built and operated inside and outside respectively of the lowest mean high water for many years (18.6 years). The Technology Catalogue follows this definition.

Since the cost and technology of offshore wind is very dependent on the depth of the seabed and the distance to the shore, it is necessary to add definition of nearshore wind. Nearshore wind is defined as offshore wind with a maximum distance to shore of 50km and in maximum sea depths of 20m; intertidal wind is considered a subcategory of nearshore wind. When the seabed depth is greater than 20 m or at a distance more than 50 km, the wind farm will be considered an offshore wind.

Different turbine types and concepts are installed in onshore and offshore wind sites, as explained in the following. The working principle is however the same, regardless of the site. 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.

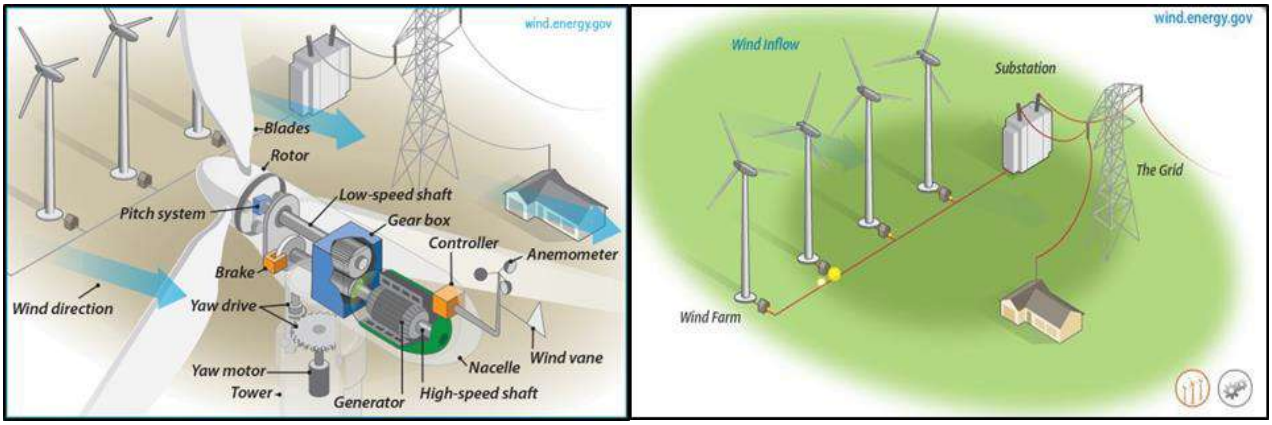


Figure 27: General turbine technology and electrical system (ref. 48)

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.

Wind turbines can be installed as single turbines, clusters or in larger wind farms. When more than one turbine is installed, additional losses may occur due to wake effects. A wake is a trail of reduced velocity and turbulent flow. If it hits a turbine downstream at a close enough distance, it will affect the energy yield and the loadings on it. In

order to avoid this, wind turbine control techniques are being developed for the cases when the available space does not allow sufficient separation in between turbines. 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.
- Power quality.

Onshore wind turbines

The typical large onshore wind turbine 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.

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

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

	Class I (High wind, HW)	Class II (Medium wind, MW)	Class III (Low wind, LW)	Class IV (Very low wind)
Average annual wind speed at hub height [m/s]	10	8.5	7.5	6.0
50-year extreme wind speed over 10 minutes [m/s]	50	42.5	37.5	30
50-year extreme wind speed over 3 seconds [m/s]	70	59.5	52.5	42

The deployment of wind energy has reduced the number of available sites with high wind resources. Wind class II to IV sites are more frequently available for new installations. While the repowering of old wind farms is growing in importance as existing units reach the end of their lifetime, new installations in sites with low-to-moderate wind are attractive today because of improved turbine design.

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

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

ρ being the air density. The real electric power delivered to the grid is affected by mechanical and electrical conversion efficiencies. With a different turbine design, LW turbines can reach an annual production comparable to that of HW turbines which, on the contrary, are physically smaller. This comes at a higher initial investment due to the bigger turbine size. As wind turbines become more reliable, efficient and less costly, it is expected that even low wind-speed conditions in near-shore and offshore locations will also be further exploited in the future.

Figure 28 shows an onshore wind resource map for Vietnam. The country is endowed with plenty of LW sites and also holds a good potential for MW sites; locations with greater wind resources are also available, but some are found in hard-to-access regions where connection to the grid is more complicated. Moreover, 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 good, the installation costs will be much higher, and it might be favourable to invest in smaller turbines that the current infrastructure can handle. However, there are cases where such infrastructure is built together with the project, e.g. the Lake Turkana project of Vestas in Kenya.

Overall, the onshore wind potential has been recently estimated to be around 42 GW, accounting for land and grid constraints (ref. 45).

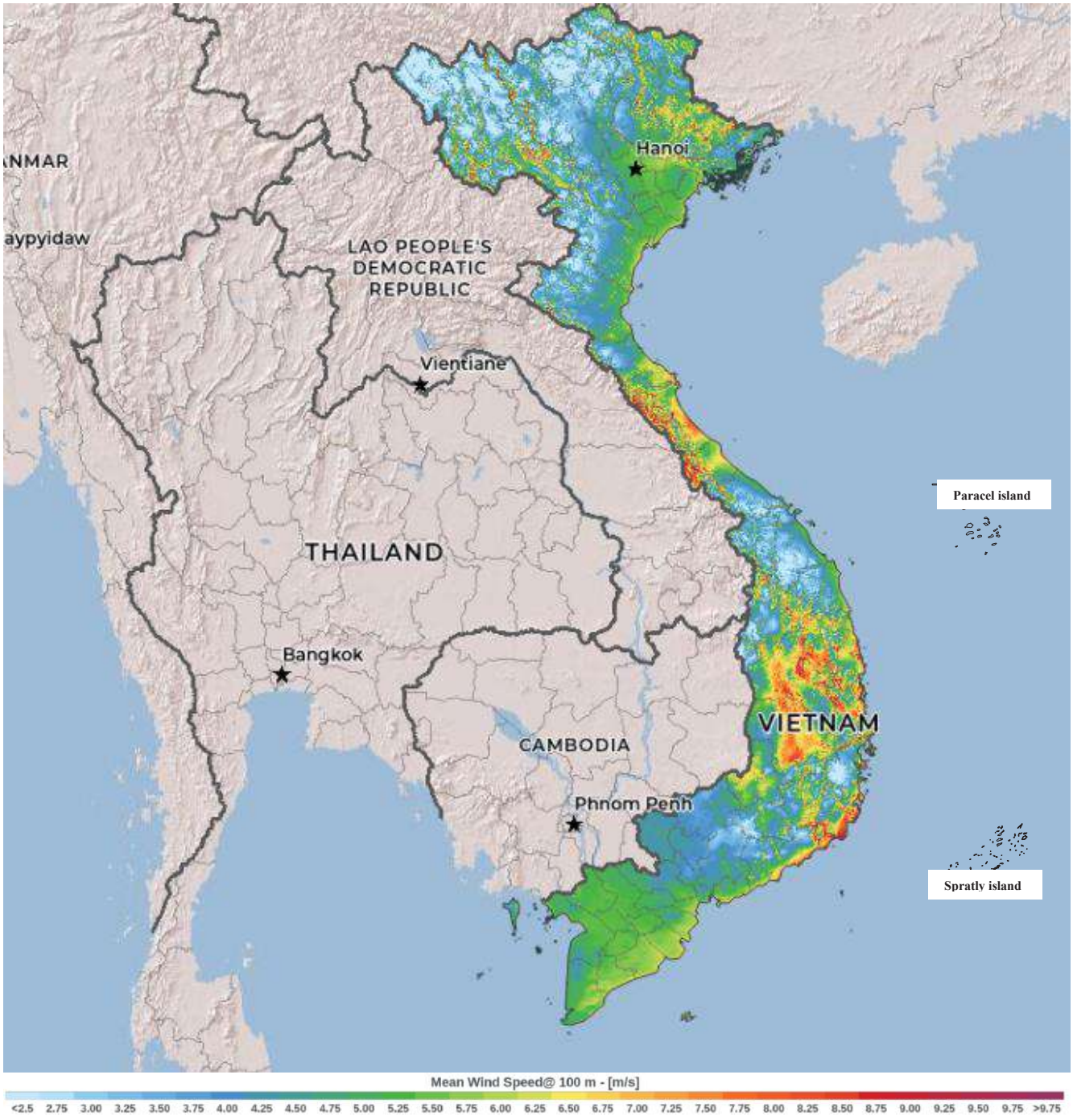


Figure 28. Wind resource in mainland Vietnam – onshore, 100m above ground. Source: Global Wind Atlas.

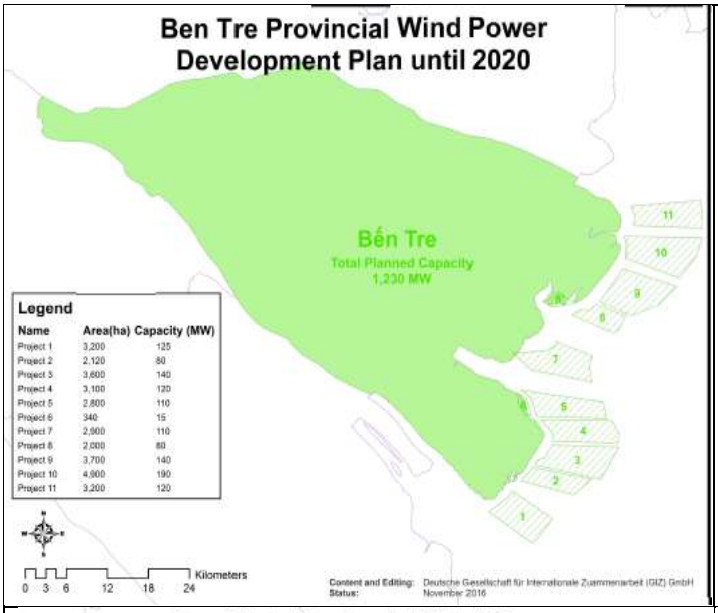
Onshore wind turbines can be installed as single turbines, in clusters or in larger wind farms. Additional losses due to wake effects can occur in large wind farms.

Offshore wind turbines

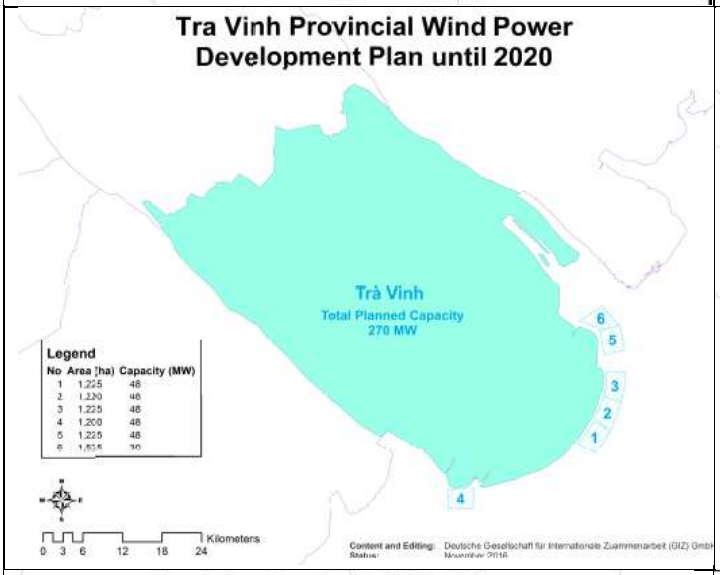
Offshore wind sites

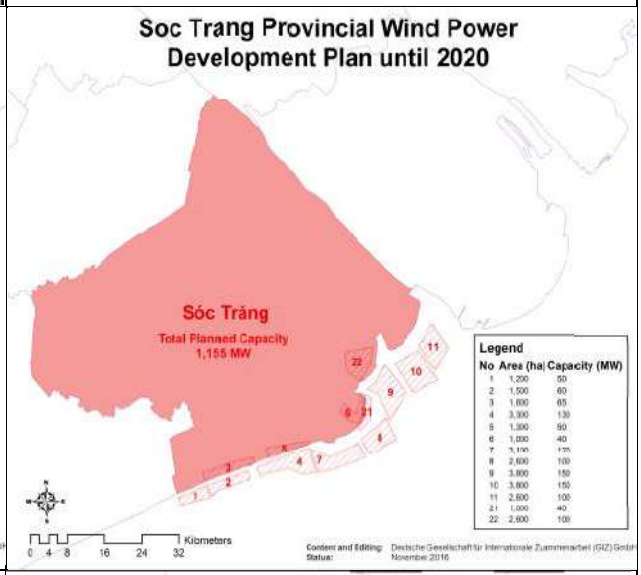
The wind resource in Vietnam is considered to be the best available in South-East Asia, for both onshore and offshore siting. However, Vietnam is also vulnerable to storms and typhoons, which can affect the deployment of

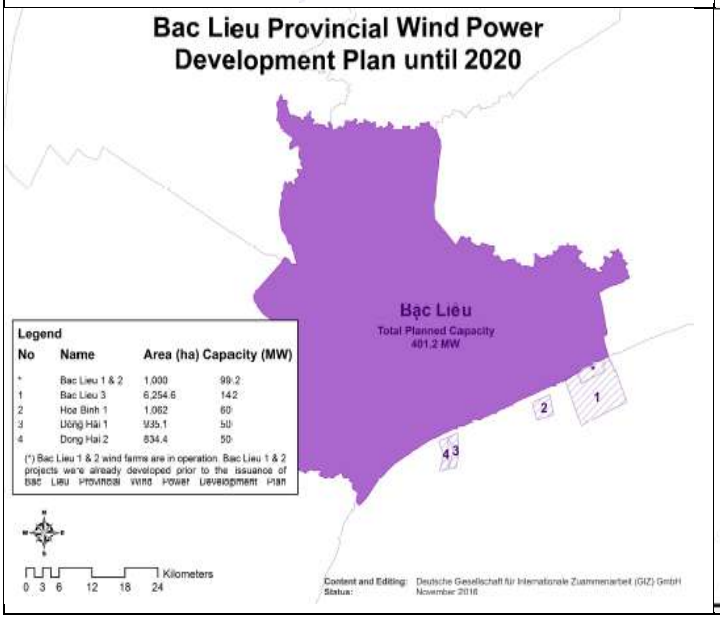
the wind farms. Nearshore is seen as a viable solution because the depth of the seabed is shallow (10-25 meters) for up to 50 kilometres offshore (Ref. 34). In the figure below a few potential nearshore sites are listed, with a total capacity of 3,400 MW. However, the offshore potential in Vietnam is deemed to be much higher than that, with estimates of over 400 GW (ref. 45).



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	







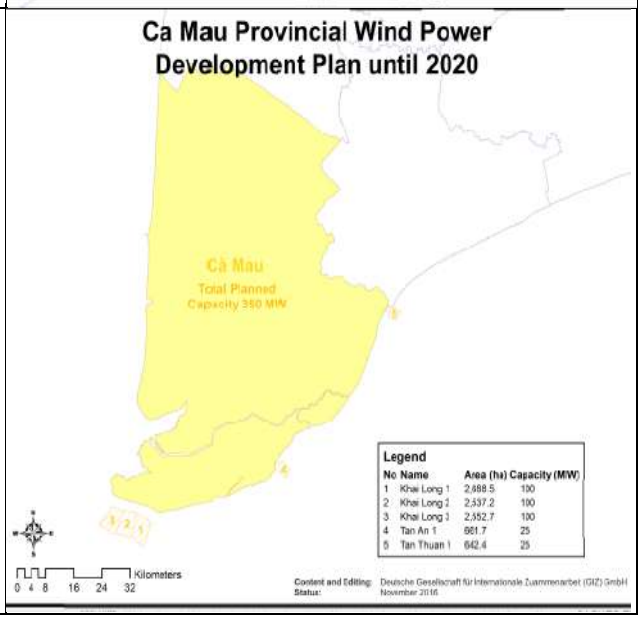


Figure 29: Examples of potential near shore sites (ref. 33).

Two key parameters define offshore wind projects: distance from shore and water depth at the location. These two allow to distinguish between offshore sites. With respect to distance from shore, offshore projects can be either nearshore or far offshore. Based on water depth, offshore projects are referred to as "intertidal" if the farm is situated in very shallow waters, normally below 2-meter depth or in the so-called intertidal zone. The turbine technology is not directly dependent on the above-mentioned classification, as it is primarily affected by the wind speed. Wind speeds generally increase with distance from shore. Intertidal turbines are therefore very similar to onshore turbines. Other aspects of offshore projects are more strictly related to the proposed classification, such as substation location, construction time, nature of electrical cables and installation logistics. In general, projects located closer to shore are less costly due to e.g. diminished towing needs (if no causeway is used), length of electrical cables and, thus, lower labour requirements. A more complete overview of differences between offshore wind projects is given below.

Characteristics of Intertidal/Nearshore Wind



- Lower and less stable wind speeds, smaller wind turbines
- Lower energy density in a given area with lower capacity factors (less efficient)
- Small scale similar to onshore wind and solar plants, normally less than 200MW
- Limited available space, suitable areas can be scarce
- May have visual, noise and shadow impact on nearshore communities
- More conflict with coastal communities and ocean users (military, shipping, fishing, tourism)
- More environmental impact as there is typically richer biodiversity in shallow water
- Less complex logistics, easier to install and maintain
- Closer to grid connection
- Less specialized supply chain - can use onshore wind supply chain
- Smaller investment, can be financed locally
- Takes ~4 years to develop and construct

Characteristics of Offshore Wind



- Higher and more stable wind speeds, larger wind turbines
- Higher energy density in a given area with higher capacity factors (more efficient)
- Large scale similar to LNG plant, up to several GW
- Abundance of space available, large potential for industry growth
- No visual, noise and shadow impact on nearshore communities
- Less conflict with coastal communities and ocean users
- Less environmental impact as there is typically less biodiversity in deeper water
- More complex logistics for installation and maintenance
- Further from grid, distance and size of windfarm requires dedicated transmission system
- Specialized offshore supply chain – requires a dedicated, long term commitment from government so supply chain can mature and costs can reduce
- Larger investment, needs international financing
- Takes ~6 years to develop and construct

Figure 30. Characteristics of Offshore and nearshore/intertidal wind power (ref. 49)

The figure below gives 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 31: Investment costs scaling factor for distance to shore and water depth for Denmark. (ref. 38).

Currently, Vietnam only has a general definition for offshore wind power according to Circular No. 39/2018 /QD-TTg dated September 10, 2018: wind projects that are built and operated outside of the lowest mean high water for many years (18.6 years). However, as depth and distance greatly affect investment cost and turbine's technology, the division of offshore wind into nearshore and "real" offshore wind is necessary. At present, there is no general definition for nearshore wind power due to its dependence on regional characteristics. In Vietnam, in some provinces in the Southwest region such as Tra Vinh, Soc Trang, Ben Tre, Bac Lieu, Ca Mau, the offshore area from the shore to a distance of 50 km has a medium seabed average of less than 20 m (Ref. 34), According to Power plan VIII, there are many wind power projects registered for investment in this offshore area. Therefore, the Technology Catalogue 2021 defines nearshore wind power as a project to build and operate wind turbines in a water below 20 m in depth and a distance to shore less than 50 km, when the seabed depth is greater than 20 m or at a distance more than 50 km will be considered an offshore wind power project (in accordance with the division of PDP VIII).

The figures below show potential wind farm locations for intertidal, bottom-fixed and floating concepts further offshore. Sites up to 100 km far from the South-Eastern coast have average wind speeds of up to 9.4 m/s at 100m hub height, which can be attractive for both fixed-bottom and floating concepts. However, grid connection costs (including reinforcements) are lower in the North of the country, as the South-Eastern region is increasingly congested as a result of renewable energy deployment (Ref. 35).

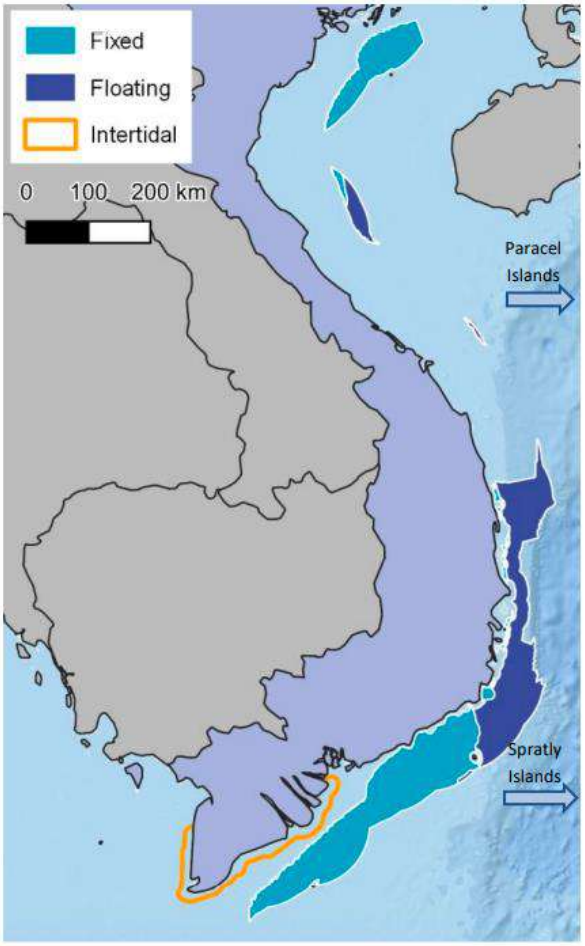


Figure 32. Potential sites for offshore wind turbines (Ref. 35). The potential for offshore wind is mainly along the coast of mainland Vietnam and the Paracel and Spratly Islands are therefore not included in the map.

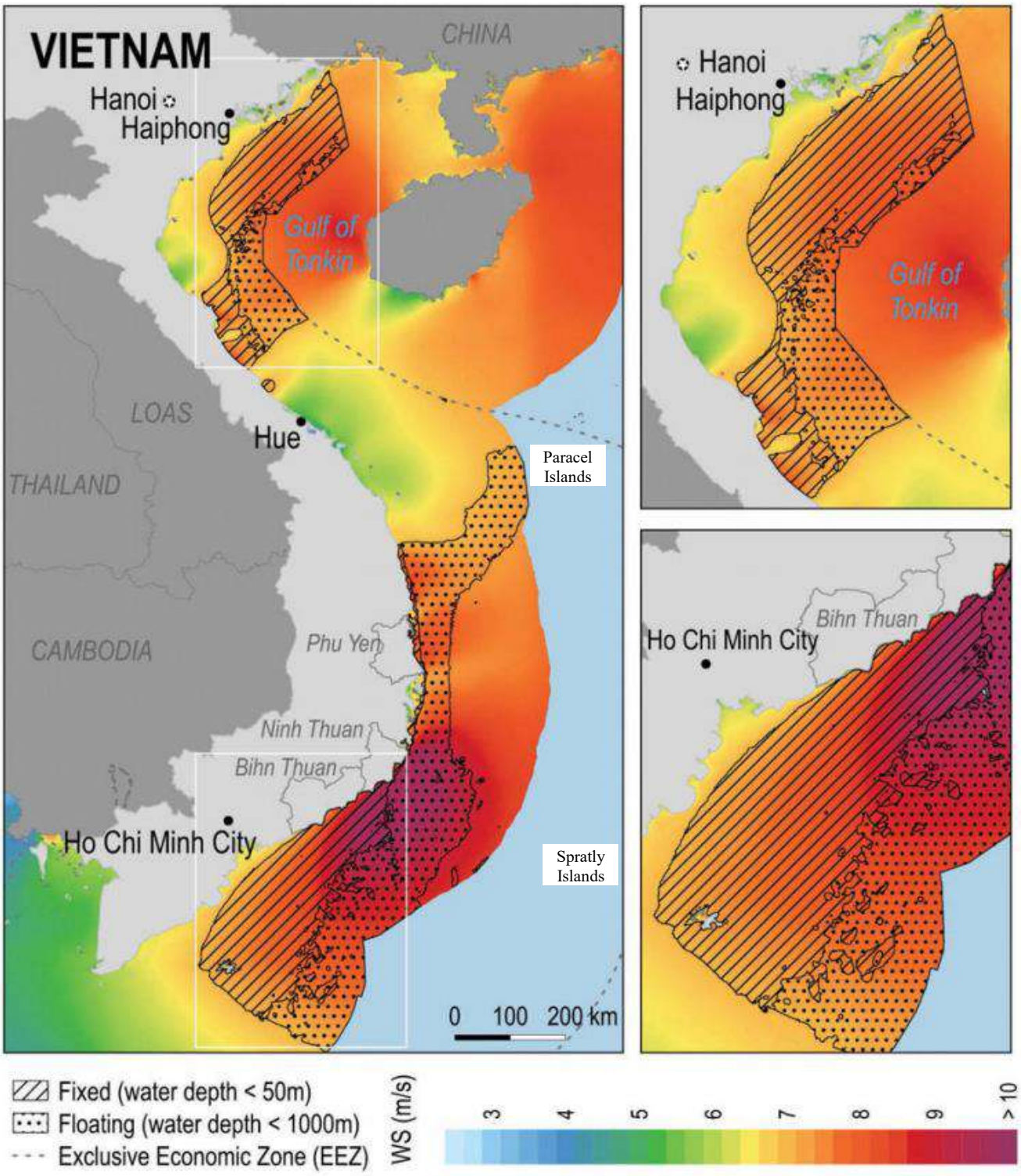


Figure 33. Map of potential offshore wind power locations in the form of floating and fixed foundations of Vietnam according to ESMAP (Ref.47)

Offshore wind technologies

In principle, the turbine technology is the same onshore or offshore, the main difference being the foundations. These can either be bottom-fixed or floating, as explained in the following sections. The other main difference between onshore and offshore wind turbines is linked to the environment they operate in. The wind resource is normally greater offshore, reaching higher average wind speeds. In addition, the hydrodynamic loads and corrosion make the conditions at sea more challenging. Hence, offshore turbines must be more robust against these conditions (Ref. 23) and able to withstand harsher environments.

Given the lower surface roughness of the sea and lower aerodynamic fluctuations, turbulence is lower offshore. This contributes to propagating the wake for a longer distance, which could affect the generation and fatigue of the

turbines. In addition, the wind shear (difference in wind characteristics with altitude) is less pronounced, which means that the wind speed does not increase as much with height. Thus, the hub height only needs to be high enough to respect the set clearance limit[13] with water (Ref. 24).

Offshore wind farms must withstand the harsh marine environment, the foundations are costly and the electrical and mechanical components in the turbines need additional corrosion protection. Offshore wind energy is still more expensive than onshore wind energy due to complexity in construction and connection to grid. In addition, there is normally no marine electrical infrastructure. Together with the high cost of installation, this results in much higher investment costs than for onshore turbines of a similar size. This demanding environment results in costly sea operations and raises the maintenance costs.

However, given that offshore wind resource is better, transport of equipment to the site is less constrained, and available onshore sites are limited, using wind energy offshore allows to build bigger turbines. Limitations for onshore wind turbines do not apply offshore, such as limited infrastructure in place. The bigger the turbine, the cheaper the cost of generating electricity, also since cost for foundation per capacity can be reduced, therefore it is desirable to have as big a rotor as possible to increase full load hours (Ref. 25), while complying with loads and environmental constraints.

Fixed-bottom offshore

Until now, fixed-bottom offshore wind farms have been installed on four different types of foundation: monopile, gravity, jacket and tripod structures. Today, monopiles and to a lesser extent jackets are the most common foundation types. The choice of which foundation type to use depends on the local sea-bed conditions and the water depth.

A nearshore wind farm is a special case of offshore wind, where waters are shallow and the installation is close to shore. This leads to lower investment costs compared to deep-water offshore wind. Nearshore wind could be considered as an intermediate class between onshore and offshore. Offshore wind turbines are being installed deeper and further from the coast.

Floating offshore

Floating wind turbines can be located in areas further from shore, where waters are deeper and fixed-bottom solutions become too costly. Moreover, wind speeds increase with distance from shore, so higher annual yield can (in principle) be achieved. This technology has been operating only in demonstration and pilot projects as of 2020, but results are promising. Floating foundations are normally used in deep water, where the depth is over 80 meters. Several concepts are under development, but three categories stand out:

- SPAR buoy (a): It is a slender cylindrical buoy floating upright. It is anchored to the floor by mooring-lines, but uses weight (ballast) on the lower part of the buoy to lower the center of gravity below the center or buoyancy and increase stability (Ref. 24, Ref. 26).
- Tension Leg (b): Numerous designs are present in the literature, but there is little consensus about an optimal design. The turbine floats on water and is connected by cables to a series of piles in the sea floor. The large buoyancy results in high tensile forces in the legs caused by the upward pull on the tension legs resulting in increased stiffness (Ref. 27).
- Semi- submersibles (c): They have a wide base to provide a stability for the turbine and are partly submerged. They are also kept in place by mooring-lines (Ref. 28).

[13] Clearance is the dampening of turbulence effects due to obstacles, ground or sea water.

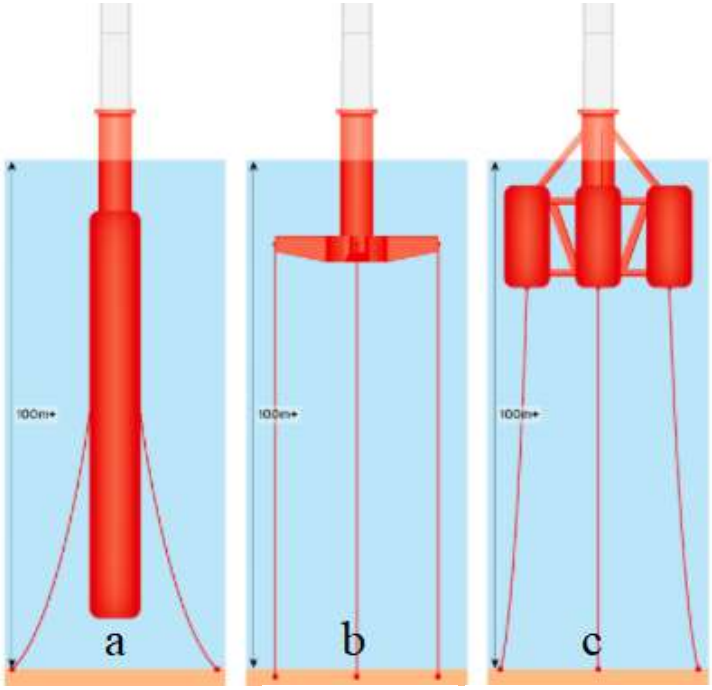


Figure 34. Different floating offshore foundations (Ref. 29).

Input
The input is wind.

Cut-in wind speed: 3-4 m/s. Rated power generation wind speed is 10-12 m/s. Cut-out or transition to reduced power operation at wind speed around 22-25 m/s for onshore and 25-30 m/s for offshore. In the future, it is expected that manufacturers will apply a soft cut-out for high wind speeds (indicated with dashed orange curve in the figure) resulting in a final cut-out wind speed of up to 30 m/s for onshore wind turbines. The technical solution for this is already available (ref. 16).

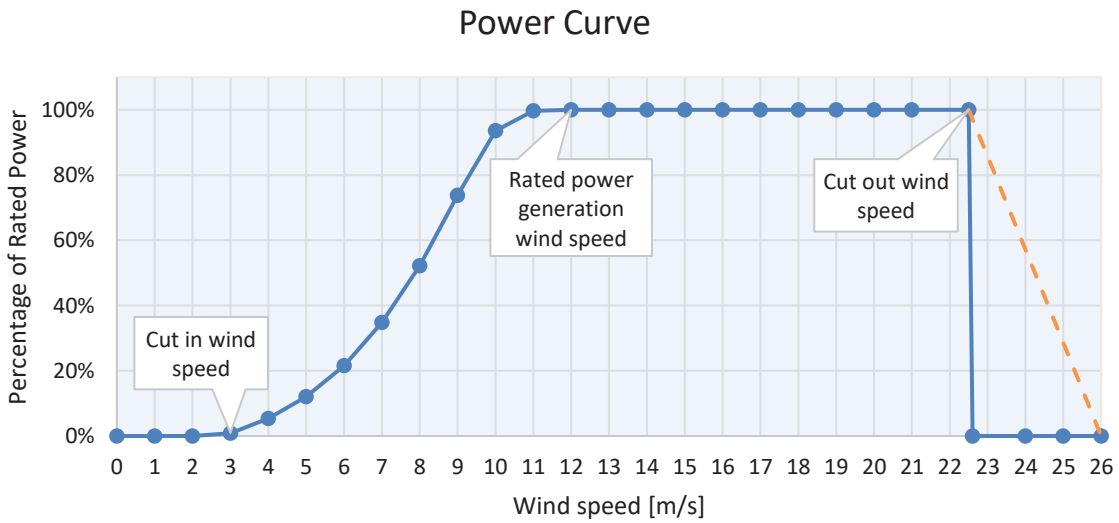


Figure 35: Power curve for a typical wind turbine (Ref. 48).

Output
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. Wake effects should always be studied before installing a wind park and wake effects increase the area needed to install wind parks with the highest possible output. 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, preferably longer-term to balance out different wind intensity over the years. Measurements should ideally be at the same height as the nacelle, but measurements can be transferred between heights accounting for the wind profile, i.e. wind speed over its height.

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 3-9 MW. Typical capacities of the demonstration floating offshore turbines range between 5 and 8 MW (Ref. 36).

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 speeds above 4-6 m/s and below 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) can also 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:
    - Onshore wind farm construction may require clearing of forest areas.
    - High population density may leave little room for onshore wind farms.
- Variable power production
- Due to the natural fluctuation of wind speed, wind forecasting needs to be performed with a certain accuracy to be able to predict generation.
- Visual impact and noise.

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

- bulk waste from the tower and foundations, even though a high percentage of the steel is recycled.
- hazardous waste from components in the nacelle.
- greenhouse gases (e.g. CO_2 from steel manufacturing and solvents from surface coatings).
- hard-to-recycle composite fibers making up the rotors.

Employment
The Bac-Lieu wind project has contributed to the creation of 111 new steady jobs (ref. 46).

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 direct employment in different industries related to wind power in Europe. Figures almost double when considering indirect employment.
Service providers include transportation of equipment, engineering and construction, maintenance, research and consultancy activities, financial services.

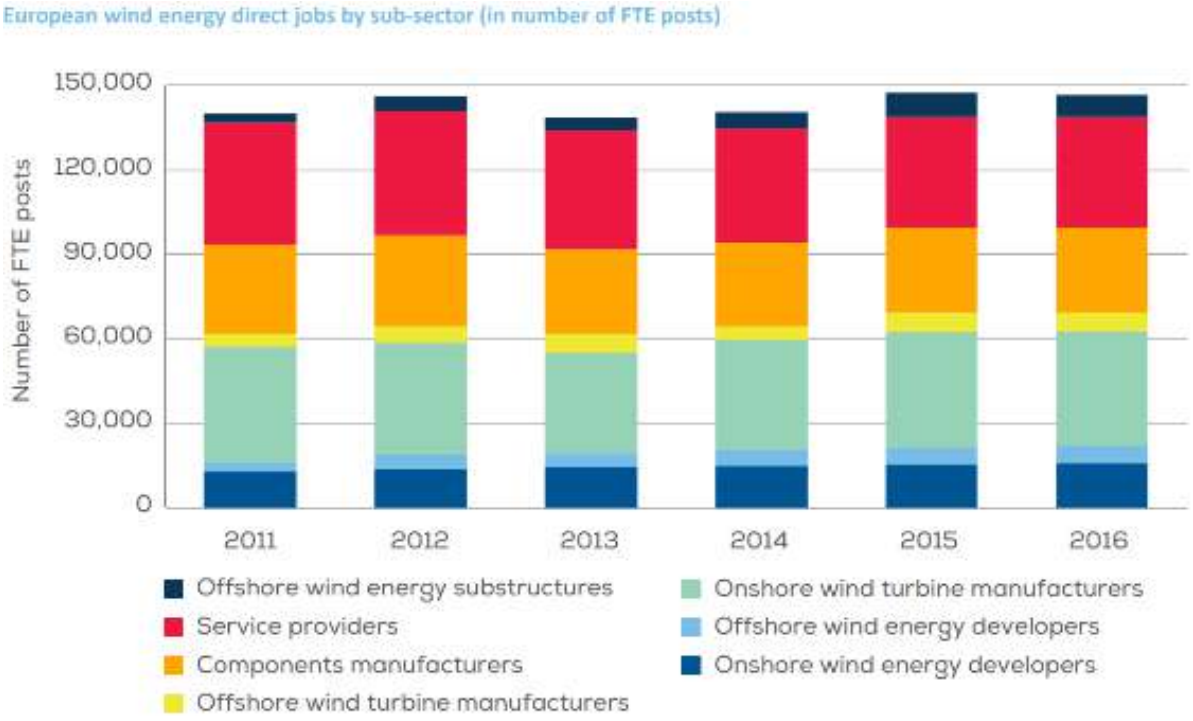


Figure 36: Direct employment (Full Time Employment) by company type related to the wind industry in Europe (Ref.6).

Research and development
The wind power technology is a commercial technology, but it is constantly improving, with costs continuously being reduced (category 3). The R&D potential is in the following aspects (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 the 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 66 kV electrical wind farm systems as alternative to present 33 kV.
    - Improved monitoring in operational phase for lowering availability losses and securing optimal operation.

Research efforts for low wind speed turbines are focusing on the following:

- Improving the rotor design with a focus on lower cut-in wind speed below 2.0 m/s[14]
- Improvement in wind turbine generator design, which involves eliminating or reducing lubricated parts and engage electro-magneto-mechanical principle of 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.

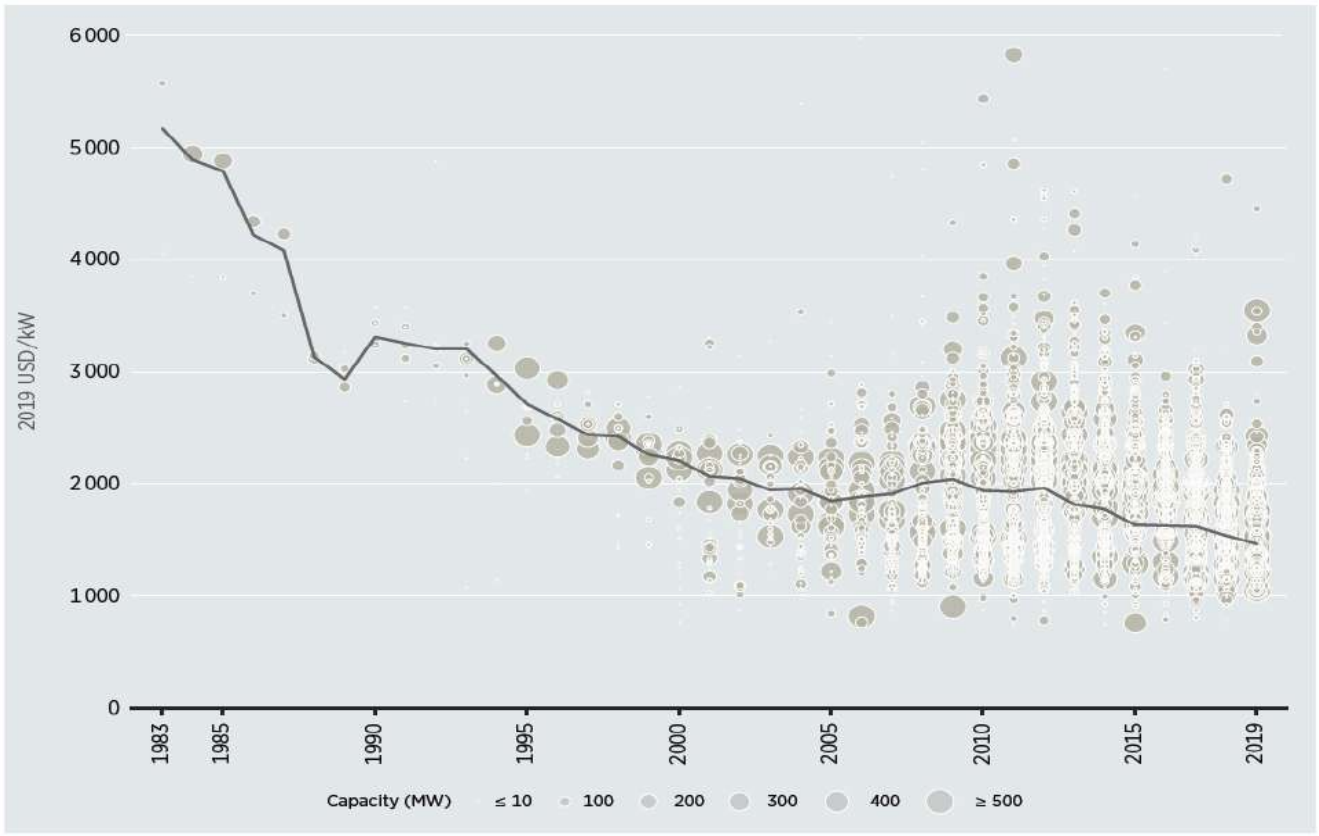
Data from IRENA (ref. 18) indicate total investment costs for onshore wind power of 1.5 M$/MW in 2019 – based on an extensive database.

In the US, average investment cost for onshore wind was just below 2.0 M$/MW in 2012, but since then, costs have decreased to around 1.5 M$/MW by 2019 (ref. 18). Reported costs for India and China have been lower, 1.1-1.2 M$/MW, according to IRENA, but substantially higher, approx. 2.4 M$/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.

[14] The cut-in wind speed is the wind speed where the wind turbine starts operating. At lower wind speeds it will not produce power.



Source: IRENA Renewable Cost Database.

Figure 37: Total installed costs of onshore wind projects and global weighted average, 1983-2019 (ref.18)

Further technological development and cost reductions by global wind turbine manufacturers can be expected. 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 bigger turbines and 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[15].

Examples of current projects

Trung Nam phase 2-64 MW
Trung Nam wind project phase 2 with capacity of 64 MW located in Bac Phong commune, Thuan Bac district, Ninh Thuan province. After phase 1 commission in April 2019, the investor Trung Nam group continue to implement Trung Nam wind project phase 2 and completed in May 2020.

The project used 16 turbines type ENERCON E-126 EP3 with capacity of 4 MW- the largest onshore wind turbine in Vietnam until 2020. The hub hight of 116 m with a rotor diameter of 126 m leads to a high specific power (320 W/m^2). The turbine uses gearless technology help to reduce the cut-in wind speed to 2.5 m/s and reduce friction and maintenance.

Trung Nam phase 2 wind project connects to 110kV busbar of Thap Cham 220kV substation and it will provide about 180 million kWh annually for the power system (~ 32% of capacity factor). With such a large turbine type, the occupied land area was planned to be only 9 ha equal to ~0.14 ha / MW. This is low compared to the prescribed land use rate of not more than 0.35 ha / MW in Circular 02/2019/TT-BCT dated 15/1/2019.

The total investment cost of the project was 93 M_{2019}$ ($2019, the administration, consultancy, project management, site preparation cost, the taxes and interest during construction are not included), which equals the nominal investment of 1.45 M/MW_p$. Total capital (including these components) is 101,7 M$, corresponding to 1.59 M$/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. It is the first intertidal wind project in Vietnam. 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 composed by 62 GE turbines of 1.6 MW each. The turbines are 82.5 m high (hub high) with more than 200 tons weight each. The turbine blades are 42 m of radius (SP~288) and made of special plastic, with self-folding control system to avoid damage when a storm surge. The capacity factor of the plant is 22.8%. The area of the whole wind farm is about 500 ha.

The investment for these two phases in Bac Lieu wind farm was 234 M$, corresponding to 2.36 M$/MW of nominal investment.

However, the wind farm is undergoing a third phase, adding 141 MW (47 turbines of 3 MW capacity) to the existing ones (Ref. 39). In addition, there is a fourth phase of 158 MW planned.

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

Future bottom-fixed offshore projects:
Several utility-scale offshore projects are expected to be connected by 2025 and a total of 5.2 GW are forecast to be installed by 2030. 500 MW are expected to be operational by November 2021.

La Gan project
Estimated to be worth $10 billion, it will be built in 2 phases, first 500 to 600 MW by 2024 and the remaining 3000 MW will be installed between 2026 and 2030, adding up to 3.5 GW.
(Ref. 40)

Thang Long project
Located between 20 and 60 km off the Binh Thuan coast, the project will be 3.4 GW. It will cost $11.9 billion. The first phase will be composed by 64 MHI vestas 9.5 MW turbines, which will start operations early 2023. The

[15] The methodology follows the methodology described in the second appendix 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

remaining phases will start operation by 2026 and are going to use MHI Vestas 10 and 12 MW turbines (Ref. 41).

Future floating offshore projects:
To date, floating offshore wind farms have been installed in test/pre-commercial initiatives and no floating project exists in Vietnam. Most of these operating wind farms are relatively small, 25-50 MW, compared to current bottom fixed projects (Ref. 36). The turbine capacities are from 6 MW in the Hywind Scotland (Ref. 42) up to 9.5 MW as in the Kincardine wind farm (Ref. 43).

Nonetheless, the size of Floating offshore wind is increasing. Norway started the construction of Hywind Tampen wind farm in October 2020, the world´s largest floating farm with 88 MW composed by 11 turbines with a capacity of 8 MW (Ref. 44).

Floating offshore wind energy will only be installed in a pre-commercial stage at the end of 2020, but will potentially make up half of the newly installed capacity by 2050. Low growth scenario estimates 400 MW of floating projects by 2035, while the high growth scenario predicts 2.9 GW (Ref. 35).

Table 15. Technical data for two representative onshore and offshore wind projects (provided by power plants).

Name	**Phu Lac (onshore)**	**Bac Lieu (near-shore)**
Year of construction	2016	2013-16
Construction time [months]	14	30 (phase 1 - 2013)
Turbine power rating [MW]	2	1.6
Wind farm capacity [MW]	24	99.2
Total area [1000 m^2/MW]	7.4	50.4
Hub height [m]	95	80
Rotor diameter [m]	100	84

Investment cost estimation
Table and Table show reviewed investment cost figures for onshore and bottom-fixed offshore respectively, including projections to 2050. While onshore installations have gained momentum, with Vietnam being the leader for number of installations in South-East Asia, offshore wind projects have yet to be commissioned. However, in 2020 the Danish Energy Agency released a roadmap for offshore wind integration identifying sites that could host over 160 GW of offshore wind power.

Recently commissioned onshore projects show investment cost figures of around 1.50 MUSD/MW. The learning rate approach has been adopted to obtain future cost data; 2019 catalogue data was adjusted downwards in light of the greater wind deployment foreseen by the IEA. A larger cost reduction is expected for offshore wind, thanks to the growing installations and the increasing technological maturity. However, today offshore wind is deemed to be significantly more expensive in Vietnam than in other locations (Europe, the US), due to a lack of local knowledge and experience in constructing, operating and managing offshore wind farm projects. In addition, the future offshore projects will be located further from the coast than Bac Lieu, an additional factor increasing costs.

The learning rate applied in the learning curve approach is set to 12.5% for both onshore and offshore wind. The learning rate approach is applied to onshore wind in Vietnam, whereas it only serves as a benchmark for offshore projects. Offshore costs are expected to decline more steeply than world trends, while starting from a higher level today.

Table 16: Investment cost figures for onshore projects, including projections.

Investment costs [$MUSD_{2019}$/MW]		**2018-19**	**2020**	**2030**	**2050**
Catalogues	**New Catalogue (2021)**		**1.50**	**1.28**	**1.08**
	Existing Catalogue (2019)		1.60	1.31	1.11
Vietnam data	Project: Phuoc Dinh	1.50			

	Project: Tay Nguyen	1.60			
	Project: Nam Phase 1	1.41			
	Project: Nam Phase 2		1.39		
	Project: Huong Linh 1		1.58		
International data	IEA WEO 2019 (average of India and China)	1.19			1.16 *(2040)*
	Danish technology catalogue		1.25	1.16	1.08
	IRENA (various)	2.37	-	1.08	0.83
	NREL ATB		2.50	1.80	1.64
	UK Government (DECC)			1.43	1.31
Projection	Learning curve – cost trend [%]	-	100%	85%	72%

Table 17. Investment cost figures for offshore projects (fixed-bottom), including projections.

Investment costs [MUSD$_{2019}$/MW]		**2018-19**	**2020**	**2030**	**2050**
Catalogues	**New Catalogue (2021)**		**3.15**	**2.15**	**1.70**
	Existing Catalogue (2019)		2.36	2.25	1.93
Vietnam data	Project: Bac Lieu (near-shore)	2.36 (*2016*)			
International data	IEA WEO 2019 (average of India and China)	3.09			1.59 *(2040)*
	Danish technology catalogue		2.39	2.16	1.99
	IRENA Future of Wind (world figures)	4.35		2.45	2.10
	NREL ATB	3.71	3.28	1.99	1.43
	UK Government (DECC)			1.83	1.57 *(2040)*
	AEGIR			2.10 *(2025)*	
Projection	Learning curve – cost trend [%]	-	100%	85%	72%

References

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

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3. Technical University of Denmark, International Energy Report - Wind Energy, 2014.
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Data sheets

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

Technology	Wind power - Onshore - Low-wind turbines								
US$2019	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	3.5	4.5	5.2						3
Generating capacity for total power plant (MWe)	30	80	100						1
Electricity efficiency, net (%), name plate								A	
Electricity efficiency, net (%), annual average									
Forced outage (%)	2.5	2.0	2.0						
Planned outage (weeks per year)	0.16	0.16	0.16	0.05	0.26	0.05	0.26		3
Technical lifetime (years)	27	30	30	25	35	25	40		3
Construction time (years)	1.5	1.5	1.5						1
Space requirement (1000 m^2/MWe)	14	14	14						1
Additional data for non-thermal plants									
Capacity factor (%), theoretical	35	36	37	20	45	20	45		
Capacity factor (%), incl. outages	34	35	36						
Ramping configurations									
Ramping (% per minute)	-	-	-	-	-	-	-	D	
Minimum load (% of full load)	-	-	-	-	-	-	-	D	
Warm start-up time (hours)	-	-	-	-	-	-	-		
Cold start-up time (hours)	-	-	-	-	-	-	-		
Environment									
PM 2.5 (gram per Nm^3)	0	0	0	0	0	0	0		
SO_2 (degree of desulphuring, %)	-	-	-	-	-	-	-		
NO_X (g per GJ fuel)	0	0	0	0	0	0	0		
Financial data									
Nominal investment (M$/MWe)	1.50	1.28	1.08	1.4	2.0	1.0	1.5	C	1, 3
- of which equipment (%)	65	65	65					B	2, 3
- of which installation (%)	35	35	35					B	2, 3
Fixed O&M ($/MWe/year)	42,000	36,000	28,000	36,500	44,600	28,700	43,100		1, 3
Variable O&M ($/MWh)	3.5	2.8	2.3	3.2	4.0	2.0	3.0		3
Start-up costs ($/MWe/start-up)	0	0	0						
Technology specific data									
Rotor diameter (m)	135	155	170	90	130	100	150		3, 4
Hub height (m)	130	150	170	85	120	85	150		3, 4
Specific power (W/m2)	245	238	229	270	350	250	350		3, 4
Availability (%)	96%	97%	97%	95%	99%	95%	99%		3, 4

References:

1 Ea Energy Analyses and Danish Energy Agency, *Technology Data for the Indonesian Power Sector - Catalogue for Generation and Storage of Electricity*, 2020

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

3 Danish Energy Agency, *Technology Data - Generation of Electricity and District Heating*, 2020.

4 IEA Wind Task 26, *International Technology Catalogue for Wind Power*, 2021.

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 Projections based on the learning rate approach

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).

Technology	Wind power - Intertidal								
US$2019	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	4.0	5.5	6.0	2.5	6.0	4.0	20.0		1, 2
Generating capacity for total power plant (MWe)	50	100	200	50	500	50	3000	D	1
Electricity efficiency, net (%), name plate									
Electricity efficiency, net (%), annual average									
Forced outage (%)	4.0	3.0	3.0	1.0	5.0	1.0	5.0	E	1
Planned outage (%)	0.3	0.3	0.3	0.1	0.5	0.1	0.5	E	1
Technical lifetime (years)	25	30	30	20	35	20	35	E	1
Construction time (years)	2.5	2.0	2.0	1.5	4	1.5	4	E	1
Space requirement (1000 m^2/MWe)	185	185	185	168	204	168	204	E	1
Additional data for non-thermal plants									
Capacity factor (%), theoretical	43%	48%	55%	-	-	-	-		
Capacity factor (%), incl. outages	41%	46%	53%	-	-	-	-		
Ramping configurations									
Ramping (% per minute)	-	-	-	-	-	-	-	B	
Minimum load (% of full load)	-	-	-	-	-	-	-	B	
Warm start-up time (hours)	-	-	-	-	-	-	-		
Cold start-up time (hours)	-	-	-	-	-	-	-		
Environment									
PM 2.5 (gram per Nm^3)	0	0	0	0	0	0	0		
SO_2 (degree of desulphuring, %)	-	-	-	-	-	-	-		
NO_X (g per GJ fuel)	0	0	0	0	0	0	0		
Financial data									
Nominal investment (M$/MWe)	2.00	1.50	1.30	1.50	3.00	1.00	2.00	C	1,4,6
- of which equipment (%)	45	50	50	40	50	40	50	A	1,4,6
- of which installation (%)	55	50	50	50	60	50	60	A	1,4,6
Fixed O&M ($/MWe/year)	55,000	40,000	32,000	40,000	100,000	25,000	45,000		1, 3, 4,6
Variable O&M ($/MWh)	4.5	3.0	2.5	3.0	5.0	2.0	3.0		1, 3, 4,6
Start-up costs ($/MWe/start-up)	0	0	0						
Technology specific data									
Rotor diameter (m)	140	170	180						1,5
Hub height (m)	110	150	175						1,5
Specific power (W(m2)	260	242	236						1,5
Availability (%)	98%	98%	98%	95%	99%	95%	99%		1,5

References:

1 4C Offshore project database.

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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 AEGIR report and the Danish TC (ref. 1 and 4 above) have been used to calculate best estimates for Vietnam.

D The wind farm size is indicative and can vary greatly from site to site. In broad terms, the average size of offshore farms increases with distance from shore due to the impact assessment.

E There is no substantial difference between intertidal and offshore wind outage and lifetime. However, towing is a less lengthy process.

Technology	**Wind power - Offshore**								
US$2019	**2020**	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data				**Lower**	**Upper**	**Lower**	**Upper**		
Generating capacity for one unit (MWe)	5.7	10.0	14.0	1.6	15.0	4.0	20.0		1, 2
Generating capacity for total power plant (MWe)	100	500	1000	50	500	50	3000	D	1
Electricity efficiency, net (%), name plate									
Electricity efficiency, net (%), annual average									
Forced outage (%)	4.0	3.0	3.0	1.0	5.0	1.0	5.0		1
Planned outage (%)	0.3	0.3	0.3	0.1	0.5	0.1	0.5		1
Technical lifetime (years)	25	30	30	20	35	20	35		1
Construction time (years)	3.0	2.5	2.5	1.5	4	1.5	4		1
Space requirement (1000 m²/MWe)	185	185	185	168	204	168	204		1
Additional data for non-thermal plants									
Capacity factor (%), theoretical	43%	48%	55%	-	-	-	-		
Capacity factor (%), incl. outages	41%	46%	53%	-	-	-	-		
Ramping configurations									
Ramping (% per minute)	-	-	-	-	-	-	-	B	
Minimum load (% of full load)	-	-	-	-	-	-	-	B	
Warm start-up time (hours)	-	-	-	-	-	-	-		
Cold start-up time (hours)	-	-	-	-	-	-	-		
Environment									
PM 2.5 (gram per Nm^3)	0	0	0	0	0	0	0		
SO_2 (degree of desulphuring, %)	-	-	-	-	-	-	-		
NO_X (g per GJ fuel)	0	0	0	0	0	0	0		
Financial data									
Nominal investment (M$/MWe)	3.15	2.15	1.70	2.00	3.50	1.40	2.00	C	1,4
- of which equipment (%)	45	50	50	40	50	40	50	A	1,4
- of which installation (%)	55	50	50	50	60	50	60	A	1,4
Fixed O&M ($/MWe/year)	70,000	42,000	39,000	40,000	100,000	25,000	45,000		1, 3, 4
Variable O&M ($/MWh)	5.0	3.1	2.7	3.0	3.7	2.0	3.0		1, 3, 4
Start-up costs ($/MWe/start-up)	0	0	0						
Technology specific data									
Rotor diameter (m)	150	200	240						1
Hub height (m)	130	170	190						1
Specific power (W(m2)	323	318	309						1
Availability (%)	97%	98%	98%	95%	99%	95%	99%		1

References:

1 Danish Energy Agency, *Technology Data on Energy Plants - Generation of Electricity and District Heat*, 2020.

2 IRENA, *Future of Wind*, 2019.

3 IEA Wind Task 26, *Wind Technology, Cost, and Performance Trends in Denmark, Germany, Ireland, Norway, the EU, and the USA: 2012–2018*, 2019

4 AEGIR, Vietnam site LCOE screening, 2020.

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 AEGIR report and the Danish TC (ref. 1 and 4 above) have been used to calculate best estimates for Vietnam.

D The wind farm size is indicative and can vary greatly from site to site

Technology	Wind power - Floating offshore								
US$2019	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	7.0	12.0	15.0						1, 2, 5
Generating capacity for total wind farm (MWe)	35	500	1000						1, 5
Electricity efficiency, net (%), name plate									
Electricity efficiency, net (%), annual average									
Forced outage (%)	6.0	4.0	4.0						3
Planned outage (%)	0.6	0.6	0.6						3
Technical lifetime (years)	20	25	30						4
Construction time (years)	3.0	2.5	2.5						4
Space requirement (1000 m²/MWe)	185	185	185						4
Additional data for non-thermal plants									
Capacity factor (%), theoretical	43%	48%	55%	-	-	-	-	D	
Capacity factor (%), incl. outages	40%	46%	52%	-	-	-	-		
Ramping configurations									
Ramping (% per minute)	-	-	-	-	-	-	-	B	
Minimum load (% of full load)	-	-	-	-	-	-	-	B	
Warm start-up time (hours)	-	-	-	-	-	-	-		
Cold start-up time (hours)	-	-	-	-	-	-	-		
Environment									
PM 2.5 (gram per Nm^3)	0	0	0	0	0	0	0		
SO_2 (degree of desulphuring, %)	-	-	-	-	-	-	-		
NO_X (g per GJ fuel)	0	0	0	0	0	0	0		
Financial data									
Nominal investment (M$/MWe)	5.50	2.65	2.00	4.00	7.00	1.50	2.50		3,4,5
- of which equipment (%)	80	65	60					A	
- of which installation (%)	20	35	40					A	
Fixed O&M ($/MWe/year)	155,000	125,000	65,000	140,000	180,000	52,000	81,000	C	4; 5; 6
Variable O&M ($/MWh)	-	-	-					C	4; 5
Start-up costs ($/MWe/start-up)	0	0	0						
Technology specific data									
Rotor diameter (m)	150	200	250						1
Hub height (m)	100	170	180						1
Specific power (W/m2)	396	382	306						1
Availability (%)	94%	96%	96%						3

References:

1 Global Wind Energy Council, 2020, "Global Offshore Wind Report 2020"

2 BVG Associates, 2020, "Offshore wind roadmap for Vietnam"

3 Borg M. et al., *Qualification of innovative floating substructures for 10MW wind turbines and water depths greater than 50m*, 2019

4 World Bank, *Offshore wind roadmap for Vietnam: Preliminary Findings,* 2020.

5 AEGIR, *Vietnam site LCOE screening*, 2020.

6 M. Aquilina, 2014, "Cost Modelling of Floating Wind Farms with Upscaled Rotors in Maltese Waters"

Notes:

A Equipment: Cost of turbines including transportation. Installation: 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 Operation and maintenance is entirely allotted to the fixed part.

D In Vietnam, floating offshore sites - further from shore - have the same average wind speeds as fixed-bottom sites.

9. TIDAL POWER

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

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

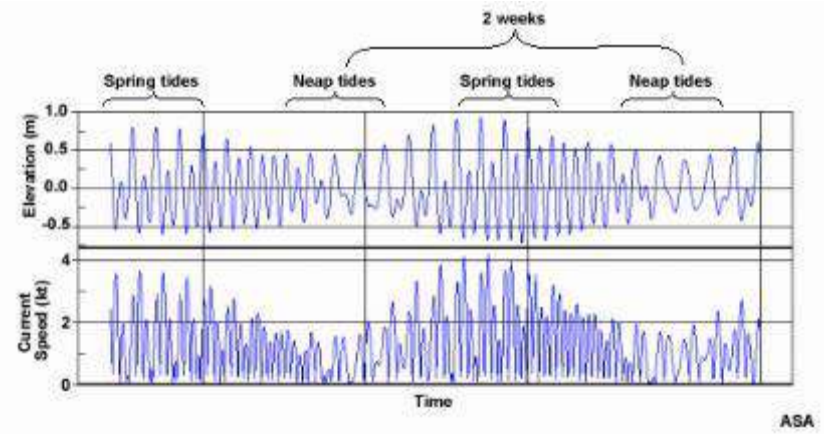


Figure 38: Time series representation of spring and neap tide along with correlation with tidal current speed variation.[3]

An important parameter with regards to tidal resources is the tidal current, which is the movement of water and flow of water currents associated with the rise and fall of tides. The tidal current resource follows a sinusoidal curve with the largest currents generated during the mid-tide. The ebb-tide (when the water level is falling) often has slightly larger currents than the flood-tide (when water level is rising). The figure above shows the correlation between tidal elevation and the speed of tidal currents. Furthermore, it is important to note that there are various non-tidal ocean currents, which can also be exploited for tidal energy, but which has not been done yet on a global scale.

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

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

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

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

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

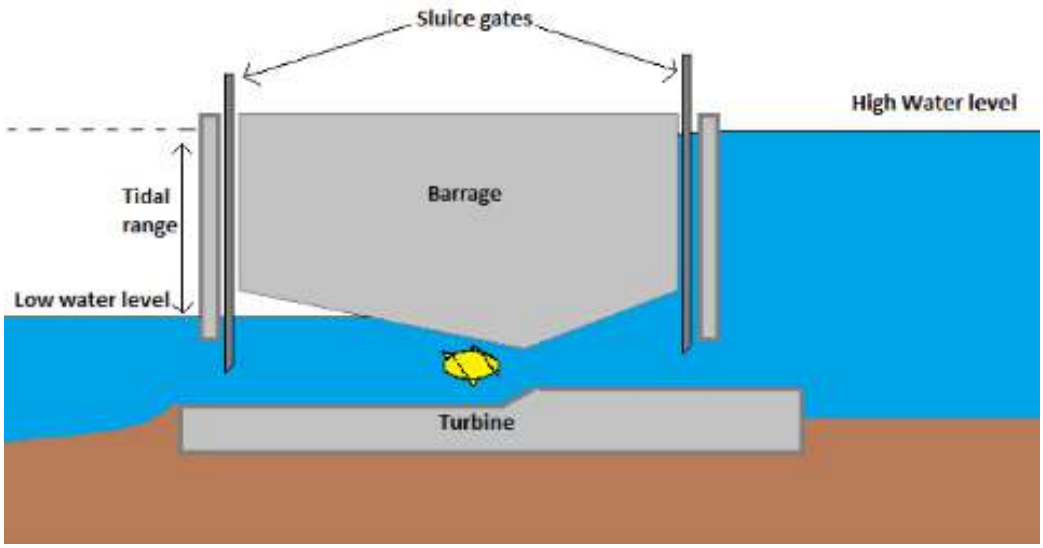
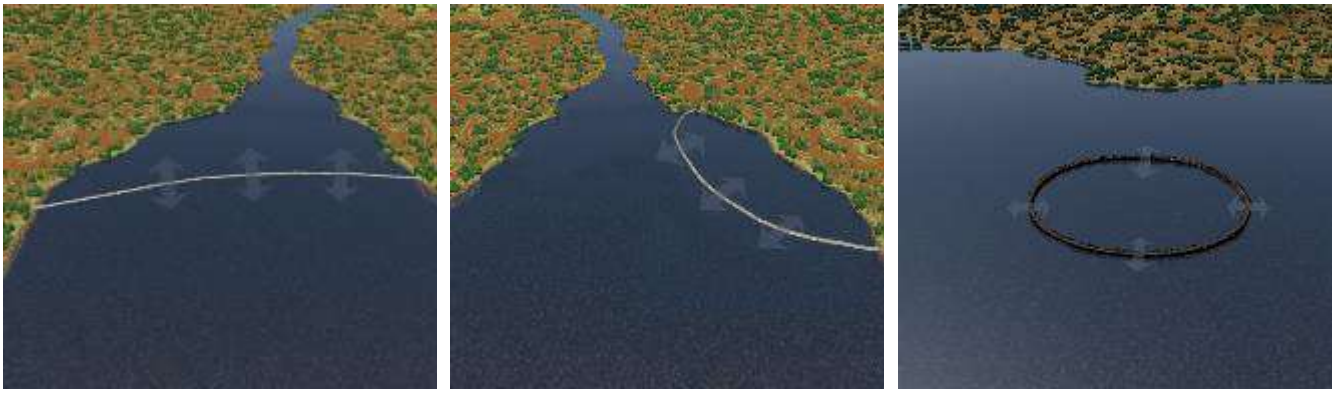


Figure 39: Schematic of tidal impoundment type plant.[4]

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

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



(a) Tidal barrage (b) Bounded tidal lagoon (c) Offshore tidal lagoon

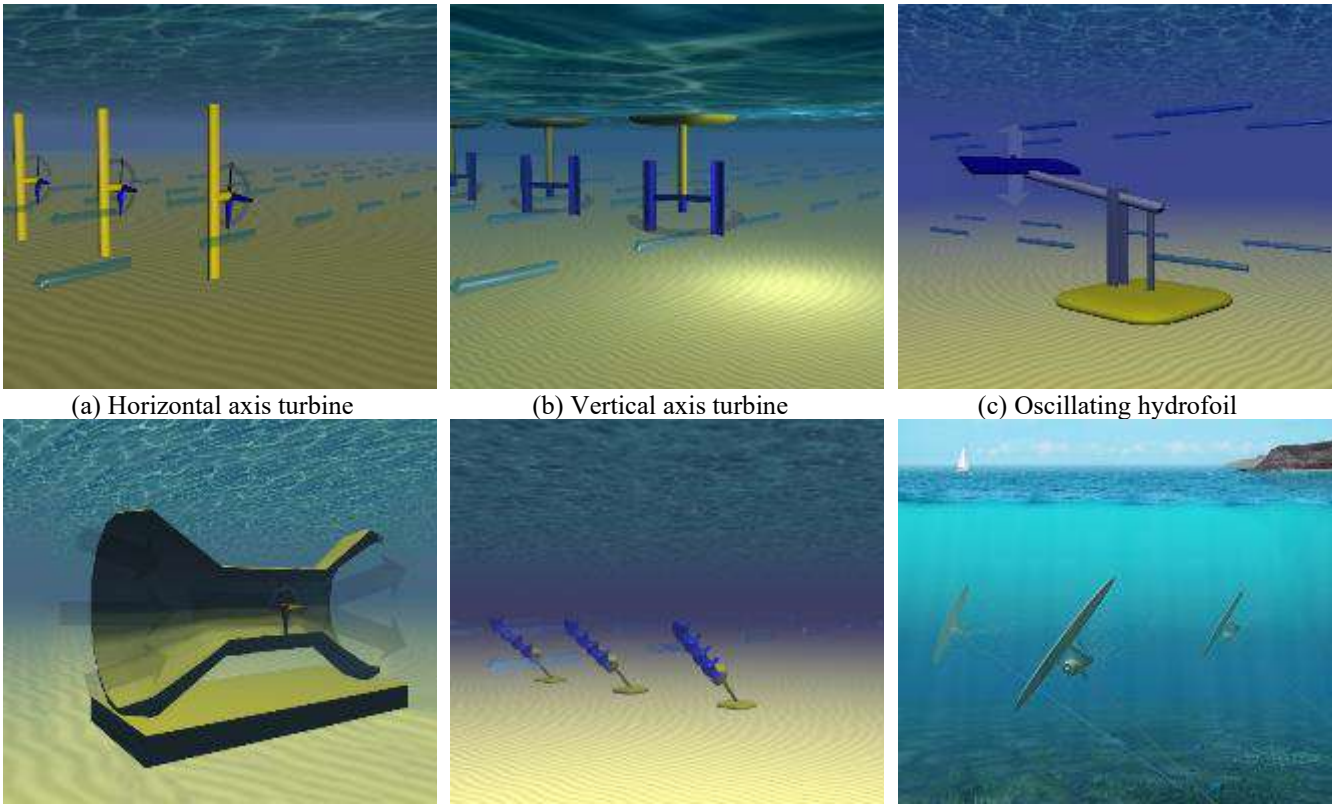
Figure 40: Tidal impoundment types [2]

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

The types of turbine technologies for tidal stream plants are [2][5]:

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

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



(a) Horizontal axis turbine (b) Vertical axis turbine (c) Oscillating hydrofoil

(d) Enclosed Tips (Venturi effect device) (e) Archimedes screw (f) Tidal kite

Figure 41: Tidal stream turbine types [2]

An overview of tidal stream projects shows that nearly two-thirds of all turbine generator assemblies are horizontal axis [6][26]. Further, most projected multi-device arrays have also settled on horizontal-axis turbines. The relative maturity of this technology reflects its similarity to well-established wind turbines. But it is also favoured due to its easy scalability and its universality, as some developers focus on hydrokinetic turbines that can also be deployed in

rivers.

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

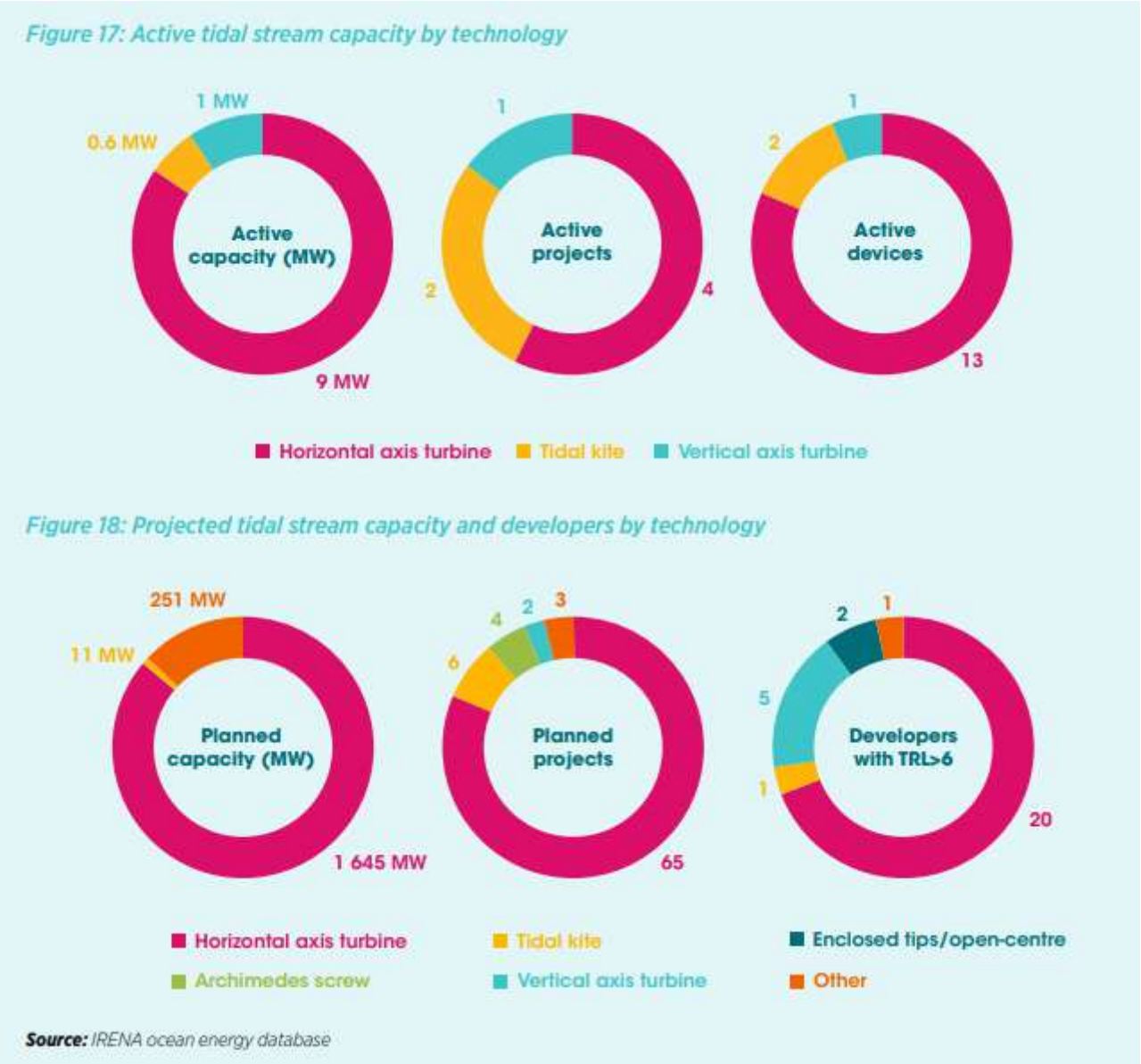


Figure 42: Active and project tidal stream capacity and technology [26]

A second classification of devices can be based on the depth of the water column and type of foundation [7].

- *First generation*: These consist of devices fastened to the sea floor. They generally operate at depths of up to 40m. The following options with which to fix the turbine to the sea floor exist:

Monopile: A tubular steel tower or turbine support structure (TSS) is embedded on the seabed and the turbine is mounted on this structure. The use of this design is limited to a water depth of up to 30m (can be up to 100-meter sea water (msw)).

Piloted: This refers to 'piled' foundations. The foundation is positioned on the seabed, then steel piles are driven through pile-guide openings in the TSS. The piles may be cemented in situ, depending on the type of seabed soils/bedrock.

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

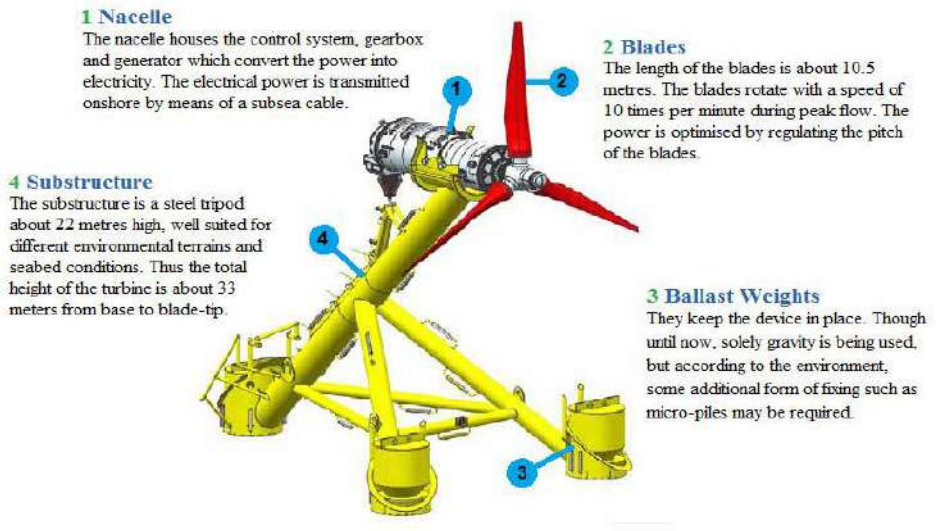


Figure 43: Early gravity based substructure design [8]

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

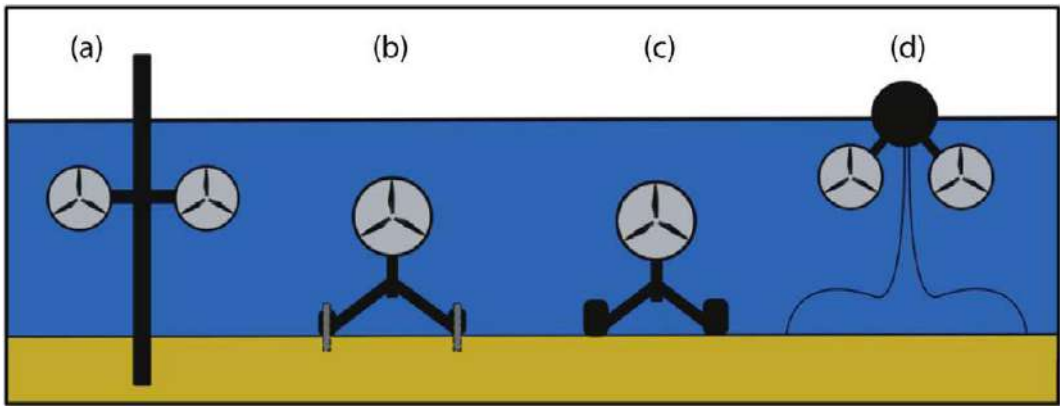


Figure 44: Foundation types: First generation devices [7]



Figure 45: Foundation types: Second generation devices - Mooring system based on wires and buoys.[7]

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

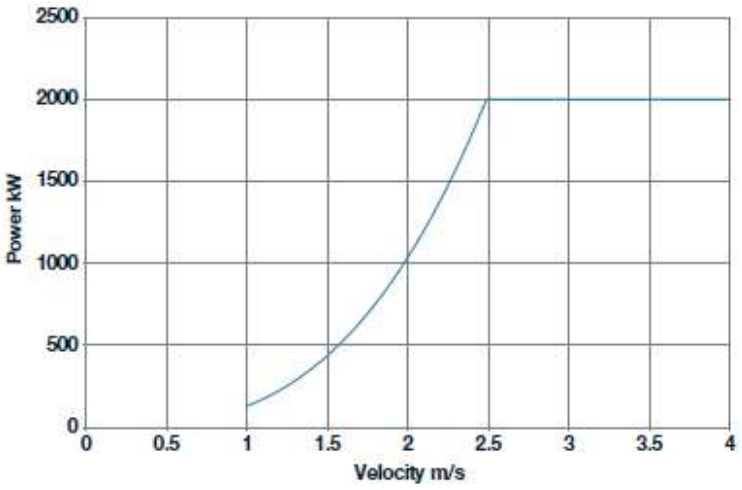


Figure 46: Sample power curve for tidal stream turbine.[9]

Globally most the tidal projects so far are around the UK, France, Canada, USA, South Korea and China. Despite having a coastline of ~3200 km, there has not been any tidal energy plants commissioned yet in Vietnam. Previously there has been some interest in setting up a tidal project in the Binh Thuan Province. Studies suggest that the Quang Ninh Coast has the highest potential for marine energy (tidal and wave). Another potential area would be the Mekong Delta region; however, this could potentially be associated with environmental issues. Estimates suggest that, in Vietnam, there is a total exploitable tidal (barrage) energy of 1753 GWh/yr. and total exploitable capacity of 5GW.[10], [11]

Input
Depending on the type of plant, the primary input can be from change in tidal elevation or movement of water due to tidal currents. Non-tidal ocean currents can also play an important role as input energy.

Output
Electricity.

Typical capacities
Globally, large-scale installed capacity so far, has been of the tidal impoundment type. Plant sizes can vary from less than 10 MW to the larger operational power plants like La Rance Tidal Power Station and Sihwa Lake Tidal Power Station being over 200 MW. Some of the future projects proposed around the world could be expected to be of much larger sizes going into GW scale [12]. Therefore, the typical capacity of tidal impoundment type plant varies a lot depending upon area available and tidal resource.

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

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

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

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

Environment
While the power generation from tidal plants is emission free, the installation of such plants has various external impacts which if not managed properly, can be a hurdle for these projects across the globe. Some of these impacts include:
- Physical changes to the water resource and surrounding coastlines. Increase in water levels and flooding in some locations, while reduced levels of water in other locations is possible due to tidal impoundment projects are possible.
- The potential change in soil quality around projects can have an impact on the ecology of the area.
- The change in tidal elevation and current after the installation of tidal projects can influence the well-being of biodiversity in the area.

- There is a potential impact on marine industries and other human activities that rely on the water bodies like fisheries, agriculture, tourism, and shipping routes.

Predicted environmental impact like flooding in nearby areas and impact on biodiversity in the area have led to the Severn Barrage project in the UK being put on hold for over a decade despite high tidal energy potential. Similarly, the Kislaya Guba tidal power plant in Russia led to diminution of tides, diminution of sea swells, reduction in the flow of fresh water from the partitioned water area to the sea, and the mechanical effect of the turbine on plankton and fish [13]. With experience and better environmental assessments, future projects could avoid at least some of these pitfalls.

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

Employment
For Europe it is estimated that a target of 100 GW ocean energy (which includes tidal energy) would lead to 400,000 jobs by 2050. This could imply that potentially 4000 jobs are created per GW of ocean energy development.[14]

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

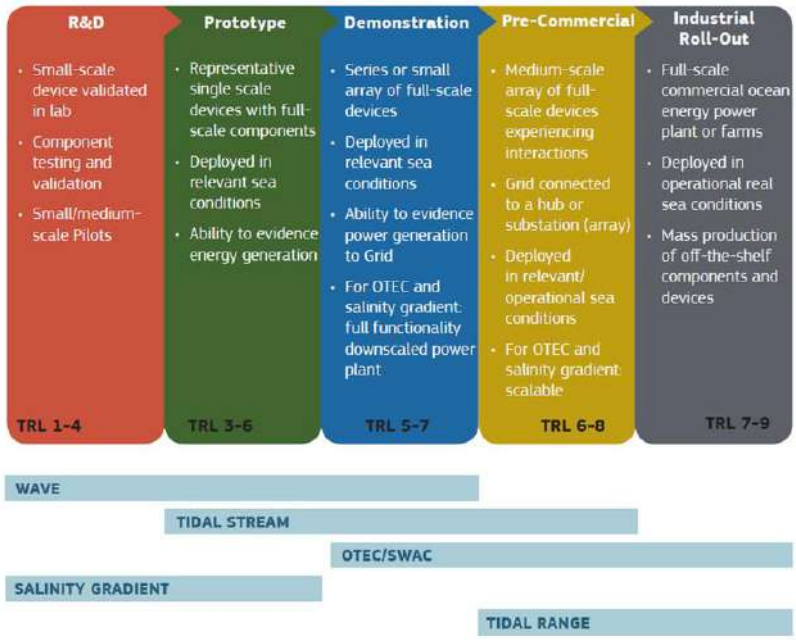


Figure 47: Where ocean energy technologies are in the stages of development [14]

Turbine: To enable turbine blades to withstand strong tidal forces, better design options need to be explored. Avoiding fatigue failure is an important design consideration for tidal turbine blades. Blades are commonly constructed from composite materials made of a polymer reinforced by carbon or glass fibres. There is scope for improvement in design to increase reliability and improve performance by improvements in blade design and innovative use of materials.[15]

One of the recent developments in turbine design is the direct-drive method which eliminates the need for the gearbox. This technology has been successfully installed in Shetland (UK) for commercial purposes. It claims to reduce the cost by a third. [16]



Figure 48: 500 kW direct drive turbine [16]

Foundations and mooring: A considerable share of the installation cost is dependent on the type of foundation structure. In most cases the type of foundation is either pin-piled or gravity based. Installation of gravity-based foundations is a costly affair as it involves lifting heavy foundation weights into position. The tidal stream sector is moving towards monopile structures as these provide the ability to position the turbine very accurately in the optimum 'zone' of the tidal flows. Also, monopiles remove the problem with gravity base structures of an uneven seabed, which is usually the case, and where extensive seabed levelling has been required. Moreover, the demand of steel is almost halved for a mono-pile solution compared to a gravity base. New techniques for pin-piling from remote-operated submarine vehicles are already reducing costs as developers move from prototypes to first arrays.[15]

Installation: In general, ocean energy technologies like tidal have a much higher overall cost than other mature renewable technology. A major reason for this is the high cost associated with contracting vessels for installation work. With improved design of components and innovative technologies like mooring systems that can be controlled remotely, the installation costs for some device types are expected to reduce substantially. Solutions like special subsea drilling techniques (as an alternative to expensive jack-up vessels) and developing installation procedures which allow use of cheaper vessels [15], are expected to reduce the cost of tidal installations.

Operation and Maintenance: Similar to installation costs, a key factor for high O&M costs for tidal devices is the cost of sea vessels. Moreover, the frequency of device maintenance is also an important reason for higher costs, as it is also linked with vessel usage. Therefore, improvements in deployability or vessel usage of tidal devices is bound to have a positive impact on the cost. An example of technology for easier maintenance is the development of tidal devices with buoyant nacelle (a cover that houses all of the generating components) which can be easily detached and floated to the surface [15]. Like with other technologies, development of predictive maintenance systems that allow for shorter and less frequent maintenance are bound to reduce costs, lesser outage periods and increased plant lifetimes.

Investment cost estimation

Even though tidal energy technology has been around for decades, there has been a very low growth in capacity. As seen in the figure below, the cumulative capacity for tidal stream plants is ~35 MW.

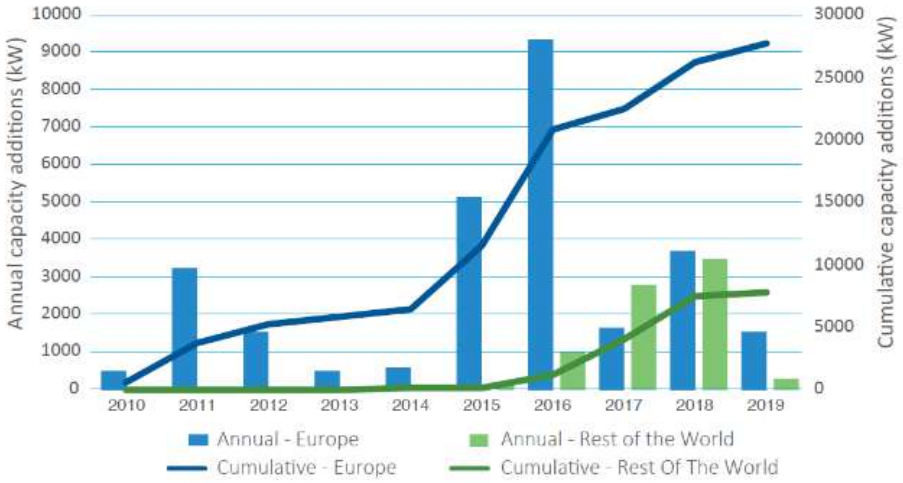


Figure 49: Installed and cumulative tidal stream energy capacity.[17]

Similarly, other than the two largest barrage projects in France and Korea of 240 MW and 254 MW, there has not been significant development for tidal impoundments even though a lot projects have been proposed. Therefore, it is difficult to assess how the cost will develop. The learning rate approach is less applicable here as the technology is still in its early stages of development and more capacity needs to be deployed before learning rate estimates can be calculated. Considering these factors, the cost estimates presented here are based on various ranges from different sources. These are associated with a level of uncertainty because the data is based on relatively old studies. The costs here take into account exchange rates to 2019 US dollars and applicable inflation.

Investment Cost for Tidal Impoundment:

Investment costs [$MUSD_{2019}$/MW]	**Estimates**	**2020**	**2030**	**2050**
New Catalogue (2021)		**5.5**	**5.1**	**5.1**
UK Government (DECC) [18]	5.3 (2.9 to 6.9)	6.9	5.3	5.3
Literature [19]	5.1 (3.6 to 5,7)	5.7	4.8	4.8
IRENA [20]	4 (proposed/planned)	4		

The recommended values for 2020 are an average of the higher values. Under the assumption that with increased deployment the costs can potentially go down, the values for 2030 show a reduction to the central values from the different ranges. However, similar to hydro costs plateauing, it is assumed here that the cost is not expected to reduce a lot more over time.

Investment Cost for Tidal Stream:

Investment costs [$MUSD_{2019}$/MW]	**Estimates**	**2020**	**2030**	**2050**
New Catalogue (2021)		**5.7**	**4.6**	**3.4**
IEA Report [21]	4.6 (3.4 to 5.7)	5.7	4.6	3.4
Commercial Developer Suggested Values	3 (in UK) 2 (in few years)			

The recommended cost for tidal stream in 2020 is the higher value from IEA report. For 2030 the central value is considered and for 2050 the lower value is taken. This is done under the assumption that, with increased deployment, the cost will decrease. However, as the technology is still in early days of development, there is a higher uncertainty with respect to the cost, as seen by the estimates given by a commercial developer. This uncertainty is accounted for in the range provided in the final data sheet.

It is expected that the learning rate for tidal stream technology in the long term will be between 5% and 10% [22], which is relatively lower than most other renewable technologies. However, there are some synergies expected between wind, hydro and marine technologies like tidal that can reduce the costs at higher rate. But this can be better predicted once there is higher capacity deployment globally.

Examples of current projects
Some examples of international projects are:

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

between the tidal turbines and the marine environment, including marine mammals. Phase 1b (80MW) is scheduled for 2021/2.[23]

The Nautilus tidal-stream project will be one of the tidal stream projects in Indonesia located in the Lombok Strait. The total cost of the commercial array has been estimated at USD 750 million. Since 2015, risk assessment; feasibility study and other reports for the project have been delivered. Agreements with the country's state-owned electrical utility company PT. Perusahaan Listrik Negara (PLN) for exclusive tidal energy site developments have been reached. For the project UK based SBS International is working with OEM partner, SIMEC Atlantis Energy to develop the 150 MW tidal turbine generator array using AR2000 turbines. The project plans to build out site capacity in three stages; stage 1: 10 MW by 2022, stage 2: 70 MW and stage 3: 70 MW by 2024.[24], [25]

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Data sheets

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

Technology	Tidal power - Impoundment Type								
US$2019	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	1	10	25	1	25	1	25	A	3
Generating capacity for total power plant (MWe)	30	100	150	10	300	10	300	B	3
Electricity efficiency, net (%), name plate	90	90	90	85	95	85	95	F	5
Electricity efficiency, net (%), annual average	90	90	90	85	95	85	95	F	5
Forced outage (%)	4%	4%	4%	2%	6%	2%	6%		
Planned outage (weeks per year)									
Technical lifetime (years)	40	40	50	30	120	30	120	C	2
Construction time (years)	5	5	4	4	6	4	6		3,5
Space requirement (1000 m^2/MWe)	0.20	0.20	0.20	0.1	0.3	0.1	0.3	D	
Additional data for non-thermal plants									
Capacity factor (%), theoretical	35	35	40	35	40	35	40	E	
Capacity factor (%), incl. outages									
Ramping configurations									
Ramping (% per minute)	50	50	50	30	100	30	100	G	
Minimum load (% of full load)	0	0	0	0	0	0	0	G	
Warm start-up time (hours)	0.1	0.1	0.1	0.0	0.3	0.0	0.3	G	
Cold start-up time (hours)	0.1	0.1	0.1	0.0	0.3	0.0	0.3	G	
Environment									
PM 2.5 (gram per Nm^3)	0	0	0						
SO_2 (degree of desulphuring, %)	0	0	0						
NO_X (g per GJ fuel)	0	0	0						
CH_4 (g per GJ fuel)	0	0	0						
N_2O (g per GJ fuel)	0	0	0						
Financial data									
Nominal investment (M$/MWe)	5.5	5.1	5.1	2.9	7.5	2.9	7.5	E	1,2,4
- of which equipment									
- of which installation									
Fixed O&M ($/MWe/year)	70,800	62,500	35,700	23,400	72,000	23,400	72,000	E	1,2,3,4
Variable O&M ($/MWh)	0	0	0						
Start-up costs ($/MWe/start-up)									

References:

1 DECC GOV.UK, "The UK 2050 Calculator: Tidal Range Cost Data", 2011.

2 Ernst & Young, "Cost of and financial support for wave, tidal stream and tidal range generation in the UK", 2010

3 IRENA, "Tidal Energy Technology Brief", 2014

4 Pacific Northwest National Laboratory (PNNL), Tethys

5 Tatiana Montllonch Araquistain, Tidal Power: Economic and Technological assessment.

Notes:

A Based on various projects and company datasheets. The turbine size can vary from project to project based on requirement. The Sihwa Lake project in Korea has 25.4 MW turbines.

B The capacity is strongly dependent on resources available and shape of coastline. Although a lot of proposed plants are much larger in size, with some being over 2 GW as well, the capacity shown here is based on deployment of plants so far.

C Actual operational life can be up to 120 years. However, lifetime is taken as 40 years, since there can be significant re-fitting costs after 40 years and discounted cash flows are insignificant after 40 years.

D Based on information of proposed plants.

E The projections here are assuming that with increased deployment and improved technology the values will improve within the range estimated.

F Bulb type turbines are commonly used for tidal impoundment plants. The value here is estimated based on efficiencies of bulb type water turbines.

G Considered as similar to Hydro.

Technology	Tidal power - Stream Type								
US$2019	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	1	2	2	0.1	6	1	6	A	3,5
Generating capacity for total power plant (MWe)	10	150	150	1	400	1	400	A	3,5
Electricity efficiency, net (%), name plate	90	92	95	87	97	87	97	B	2,3,5
Electricity efficiency, net (%), annual average	90	92	95	87	97	87	97	B	2,3,5
Forced outage (%)	4%	4%	4%	2%	6%	2%	6%		2
Planned outage (weeks per year)									
Technical lifetime (years)	25	25	30	20	30	20	30	B	
Construction time (years)	3	2	2					C	
Space requirement (1000 m^2/MWe)									
Additional data for non-thermal plants									
Capacity factor (%), theoretical	33	35	37	33	40	35	40	B	1,2,4
Capacity factor (%), incl. outages	33	35	37	33	40	35	40	B	1,2,4
Ramping configurations									
Ramping (% per minute)	-	-	-						
Minimum load (% of full load)	-	-	-						
Warm start-up time (hours)	-	-	-						
Cold start-up time (hours)	-	-	-						
Environment									
PM 2.5 (gram per Nm^3)	0	0	0						
SO_2 (degree of desulphuring, %)	0	0	0						
NO_X (g per GJ fuel)	0	0	0						
CH_4 (g per GJ fuel)	0	0	0						
N_2O (g per GJ fuel)	0	0	0						
Financial data									
Nominal investment (M$/MWe)	5.7	4.6	3.4	3.0	7.1	2.0	7.1	B	1,2,3
- of which equipment (%)	87	87	87	83	91	83	91		1,2
- of which installation (%)	13	13	13	9	17	9	17		1,2
Fixed O&M ($/MWe/year)	283,622	230,298	114,718	92,700	412,000	92,700	412,000	B	1,2
Variable O&M ($/MWh)	12	9	7						4
Start-up costs ($/MWe/start-up)									
Technology specific data									

References:

1 Ernst & Young, “Cost of and financial support for wave, tidal stream and tidal range generation in the UK”, 2010.

2 Ocean Energy Systems - OES (IEA), “International Levelised Cost of Energy for Ocean Energy Technologies”, 2015.

3 SIMEC Atlantis Energy, Projects

4 UK Govt., Electricity Generation Costs 2020 (back calculation from LCOE values)

5 Pacific Northwest National Laboratory (PNNL), Tethys

Notes:

A Projects are in the early stages, turbines and capacities are smaller. Larger projects are expected to be executed in smaller capacity phases.

B The projections here are assuming that with increased deployment and improved technology the values will improve within the range estimated.

C Estimated based on MeyGen tidal stream project

10. WAVE POWER

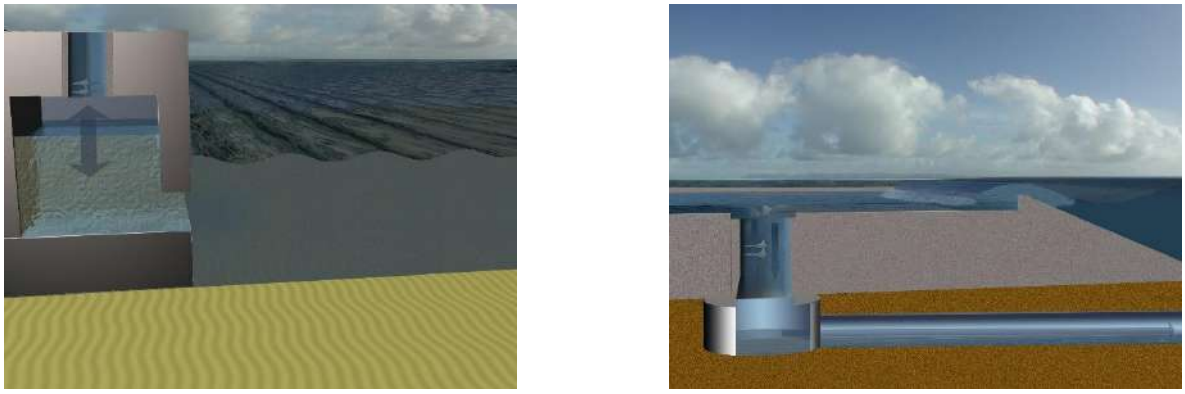
Brief technology description
Under the marine energy umbrella, one of the technologies being explored is production of electricity from wave energy. These technologies aim to exploit the energy from the movement of waves.

The flowing of wind over the surface of the water leads to the formation of waves. Wave size is dependent on the wind speed, duration, and the distance of water over which it blows (the fetch), bathymetry (depth) of the seafloor and currents. Wave energy devices harness the kinetic energy from this movement of water.

As this technology is still in the early stages of development, there are various types of wave energy devices being explored. The following are some of the first generation wave energy converters (WECs) being developed globally [1], [2]:

Oscillating Water Column (OWC): It is a partially submerged, hollow structure, which has an opening at the bottom allowing the seawater to enter, enclosing a column of air above the column of water. Waves cause the water column to rise and fall, which in turn compresses and decompresses the air column. This trapped air flows to and from the atmosphere via a turbine, which usually has the ability to rotate regardless of the direction of the airflow. The rotation of the turbine is used to generate electricity.

Overtopping Device: In this type of system, the waves flow over a wall, and the water is collected in a storage reservoir. The incoming waves create a head of water, which is released back to the sea through conventional low-head turbines installed at the bottom of the reservoir. An overtopping device may use collectors to concentrate the wave energy. Overtopping devices are typically large structures due to the space requirement for the reservoir, which needs to have a minimum storage capacity.



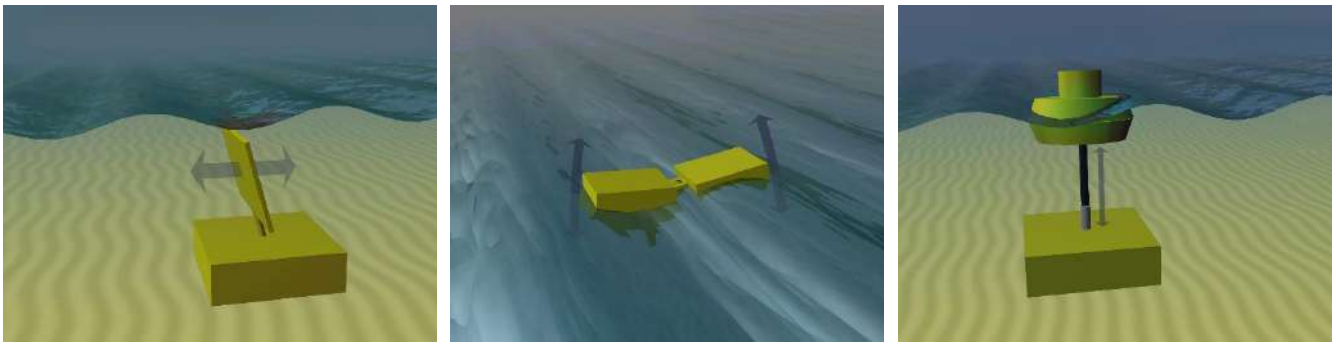
(a) Oscillating water (b) Overtopping device

Figure 50: Wave energy collectors/convertors [2]

Oscillating Wave Surge Converters: Using the principles of an inverted pendulum, this device operates near the water surface. It is mounted on an extension/arm pivoted at the seabed. The arm oscillates with wave movements.

Attenuator: It is a floating device positioned parallel to the wave direction allowing it to effectively ride with the wave movement. The device effectively captures the energy as the wave moves past by selectively constraining the movements along its length.

Point Absorber: A point absorber is a floating structure, which absorbs energy from all directions through its movements at/near the water surface. It converts the motion of the buoyant top relative to the base into electrical power.



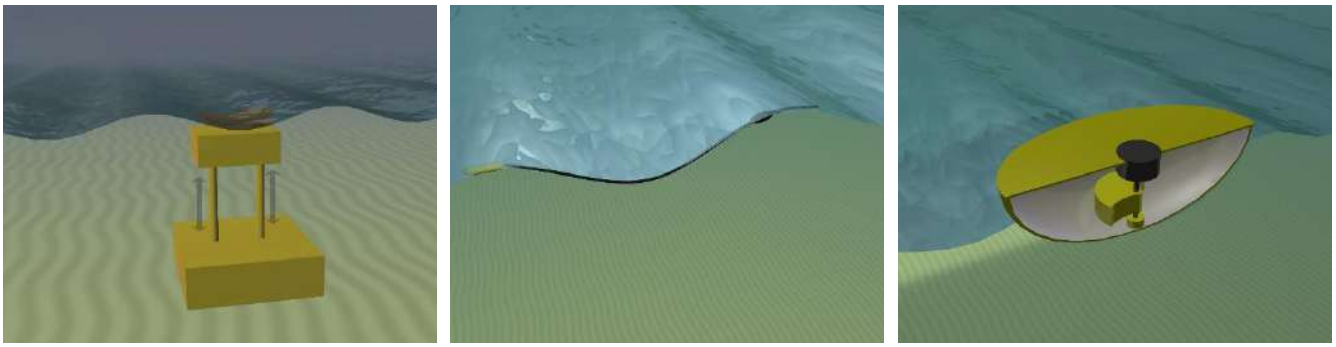
(c) Oscillating wave surge converters (d) Attenuator (e) Point absorber

Figure 51: Wave energy collectors/convertors [2]

Submerged Pressure Differential: Submerged pressure differential devices are typically located near shore and attached to the seabed. The motion of the waves causes the sea level to rise and fall above the device, inducing a pressure differential in the device. The alternating pressure pumps fluid through a system to generate electricity.

Bulge Wave: Consists of a rubber tube filled with water, moored to the seabed heading into the waves. The water enters through the stern and the passing wave causes pressure variations along the length of the tube, creating a 'bulge'. As the bulge travels through the tube it grows, gathering energy which can be used to drive a standard low-head turbine located at the bow, where the water then returns to the sea.

Rotating Mass: Two forms of rotation are used to capture energy by the movement of the device heaving and swaying in the waves. This motion drives either an eccentric weight or a gyroscope causes precession. In both cases the movement is attached to an electric generator inside the device.



(f) Submerged pressure differential (g) Bulge wave (h) Rotating mass

Figure 52: Wave energy collectors/convertors [2]

WECs can be categorised in many ways, based on device size and directional wave characteristics, working principle and location. While there is no internationally agreed upon categorisation of WECs, a common way of classification is based on location. The categories are [3]:

1. Onshore devices: These are placed near the shore and generally above the sea or in shallow waters. The ease of access makes these devices easy to operate and maintain, and they do not require moorings or long lengths of sea cables. However, the waves are not as strong near the shore due to their interaction with the seabed. Also, suitable sites for onshore deployment can be difficult to find and might need to overcome environmental hurdles.
2. Nearshore devices: These are usually located a few hundred metres from the shoreline and installed in moderate water depth of 10-25 m. As these devices usually rest on the seabed, they do not require mooring. In some cases, the device can also be floating type, and mooring may be required.
3. Offshore devices: These devices are located far from the shore, in water depths usually greater than 40m. They are either floating or submerged type moored to the seabed. While the wave resource is significantly higher at these locations, the harsh conditions require a much sturdier device and lead to increased cost. Moreover, their operation and maintenance can be complicated, and long sea cables are required to carry the electricity to the nearest grid connection point.

The majority of the projects globally are exploring offshore devices.

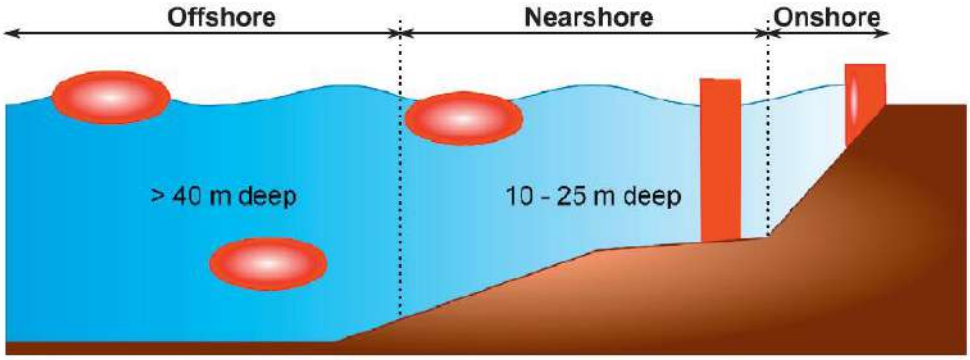


Figure 53: Location of wave energy converters [3]

From the discussion so far, it is evident that the mooring system of these devices is an important aspect. Mooring design is closely related to the location and working principle of the WECs. Based on the layout configuration of the mooring system, it can be categorised into the following [4]:

1. Spread mooring system, which consists of the multiple mooring lines connected directly to the WEC.
2. Single point mooring systems in which the WEC is free to rotate about its hull. This includes turret mooring system, Catenary Anchor Leg Mooring (CALM) and single anchor leg mooring (SALM).

Another categorisation of mooring systems is based on their role in operation:

1. Passive mooring is only responsible for keeping the WEC in position.
2. Active mooring, in addition to keeping the WEC in position, also helps with optimising the energy capture.
3. Reactive mooring is suited for designs where the power-take-off (PTO) extracts energy using he relative movements between the WEC and the seabed.

The next part of the system is the power-take-off (PTO) arrangements. There are various configurations based on the type of WEC and the location of the wave farm. In most designs, the primary conversion stage involves converting the hydrodynamic energy from the incident wave into mechanical energy, which then leads to the secondary conversion of converting mechanical energy to electrical energy. In some cases, the incident wave energy is directly converted to electrical energy using linear generators, aegir dynamo, magnetohydrodynamic generator, electroactive polymer artificial muscle or contactless force transmission system.[5] Most of the direct conversion technologies are still under development and have not been used widely.

In the first configuration, the working fluid can be air, water or other compressed fluids like high-pressure oil or low-pressure water. The type of turbine is dependent on the working fluid. Air turbines include Wells turbine, Denniss-Auld turbine or impulse turbine. Hydro turbines can include the Francis, Kaplan, or Pelton turbine. The air turbines are mostly used in OWC type WECs. An advantage with air turbines is that they are not in direct contact with the potentially corrosive salty water and potentially destructive high waves; also, they are easily accessible for maintenance [3], [5]. The advantage of the hydro turbines is that they are a well-known technology and therefore they are easily available and economic to use.

The final piece of the puzzle, similar to most other generation technologies, is the power transmission system consisting of converters and transformers, and cables necessary to get the power to the grid. The different stages can be summarised through the figure below.

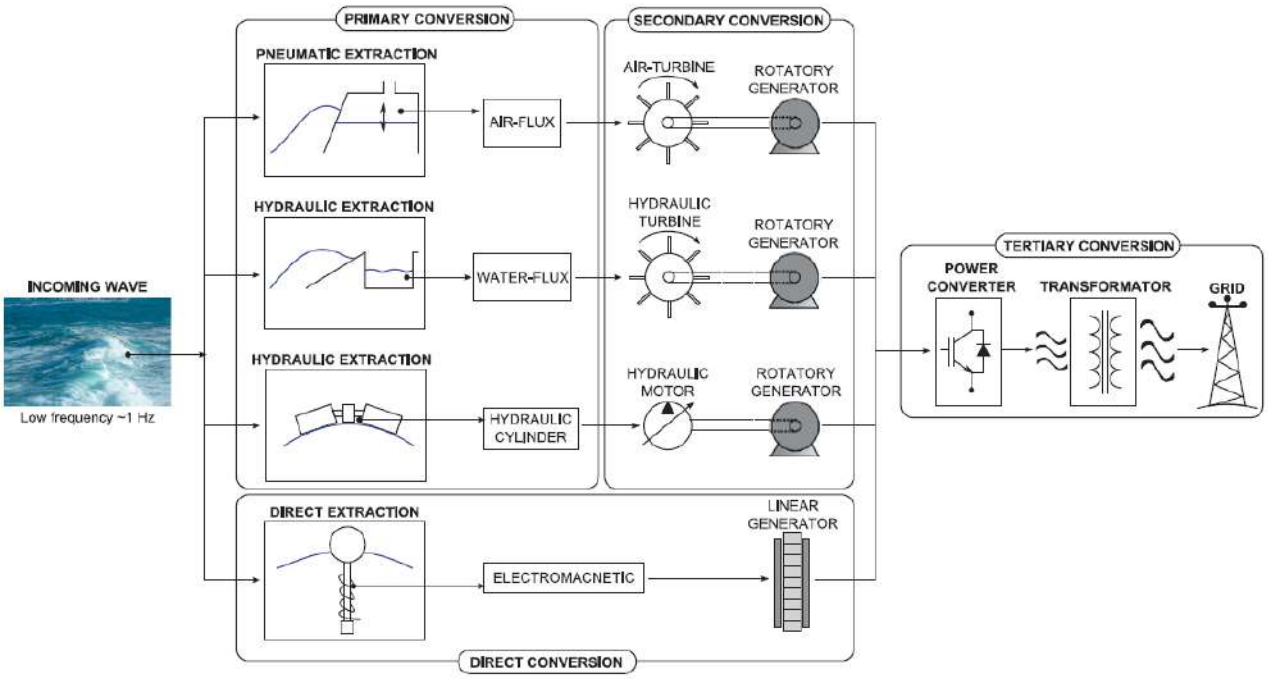


Figure 54: Wave energy conversion stages [3]

As mentioned, the system design is dependent on the wave resource available. This is estimated based on the wave energy flux (kW/m) which is the transport rate of the wave energy through a vertical plane of unit width, parallel to a wave crest. It is dependent upon the significant wave height, and the peak wave period. Another factor that influences the wave energy is the wind resource. The figure below helps with visualising these different aspects.

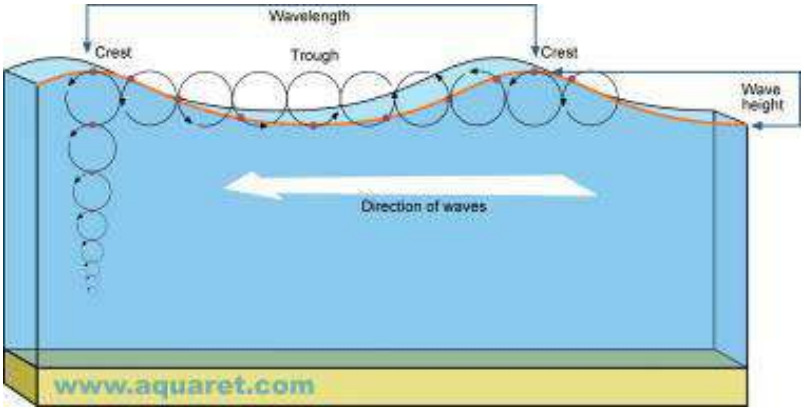
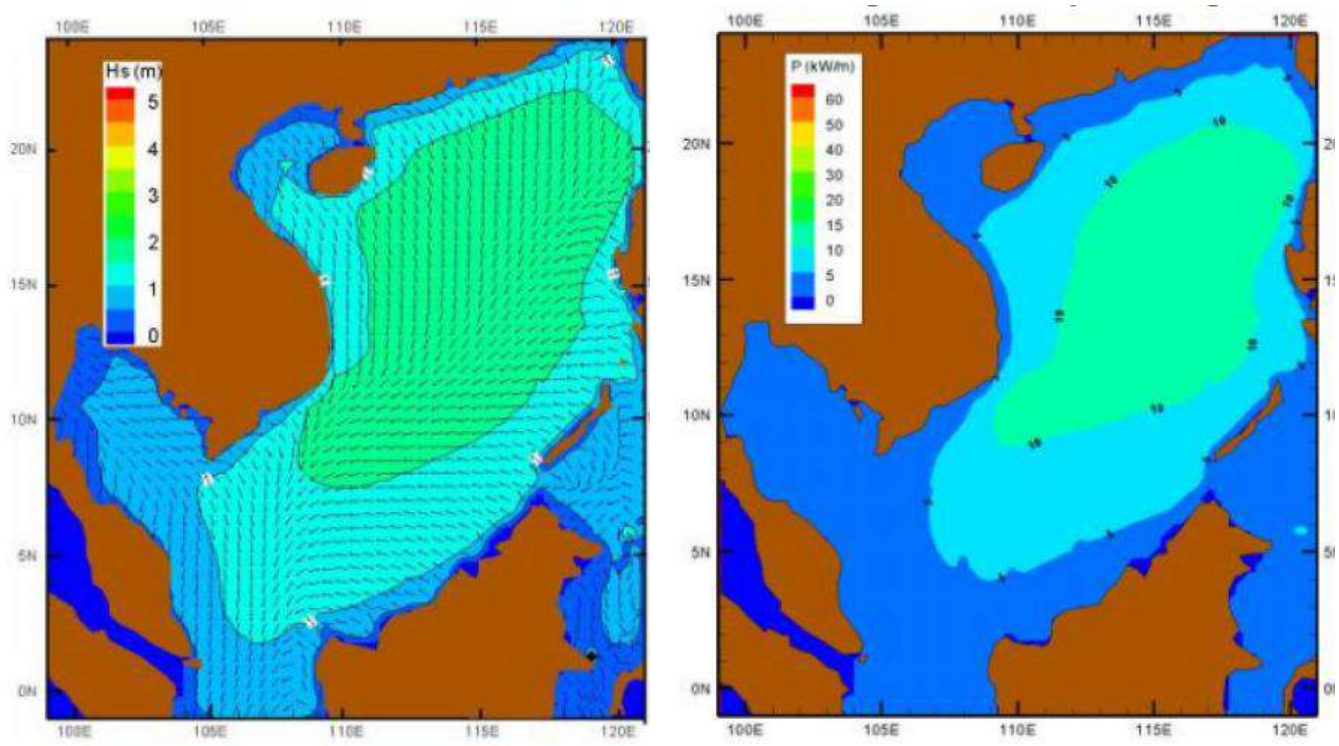


Figure 55: Wave characteristics [2]

The yearly average of wave height and wave energy flux for Vietnam can be visualised from the figures below. Vietnam, with a coastline of over 3000 km, has some good locations of wave energy with offshore wave energy flux varying from 40-411 kW/m. [6] It is important not to confuse these values with onshore or nearshore values, and also to remember that peak and average values can be very different. Moreover, a crucial factor is the monsoon season experienced at the site.



(a) Yearly wave height *(b) Yearly wave energy flux*

Figure 56: Wave energy resource in Vietnam [7]

A study found that there is an annual potential of 212 TWh from wave energy along the Vietnamese shoreline. According to this study, the best wave energy resource can be found from Quang Ngai to Ninh Thuan, accounting for 42.4% of the potential. This was followed by area from Quang Binh to Quang Nam and from Binh Thuan to Bac Lieu accounting for 17.2% and 14.7% of the potential respectively.[8] Another study identified Truong Sa (Khanh Hoa), Phu Quy (Binh Thuan), Cu Lao Cham (Quang Nam), Con Co (Quang Tri), and Hon Me (Thanh Hoa) as potential sites for wave farms.[6]

Input
Hydrokinetic energy from incident waves.

Output
Electricity. Some systems are designed to pump water and produce potable water.

Typical capacities
As this technology is still under development, the electrical output from wave power converters is in some cases generated by electrical connected groups of smaller generator units of 100 – 500 kW, in other cases several mechanical or hydraulically interconnected modules supply a single larger turbine-generator unit of 1 – 3 MW. These sizes are for pilot and demonstration projects. Commercial wave power plants will comprise a large number of devices, as is the case with offshore wind farms. [9]

Ramping configurations
The ramping or regulating ability of the system depends on the design of the PTO system. In general, the systems are developed with the aim of allowing maximum absorption by the WEC from the incoming waves at a given time. Moreover, the configuration is setup to also enable disconnection of the system from the grid if required for safety or other reasons. Wave power is more predictable than other sources, which could mean that various advanced predictive control models could be applied in the future. [9]

Advantages/disadvantages
Advantages:

- Wave power is non-emissive and renewable.
- As the wave farms are usually located in the water body, there is limited visual impact.
- Wave resources are relatively more predictable compared to wind.

- Extracting energy from waves can help costal protection, as the wave heights are reduced.
- No difficulties for fish and aquatic animals.
- Strong synergies with wind and other technologies like tidal stream.

Disadvantages:

- As the technology is still in its nascent stage, there is a long way to go before the industry converges on one design. Moreover, mass deployment is required to achieve competitive cost reduction.
- The cost for operation and maintenance and connection to the grid is still high.
- While it is a predictable resource, it is variable and cannot produce energy when the waves are static.
- Offshore wave energy equipment can affect navigation.

Environment

A positive life cycle impact is expected. Planned in cooperation with navigation, oil exploitation, wind farms and fishing industry wave power plants are expected to have a positive impact on the living conditions for fish in the sea, by providing sheltered areas. [9] However, there are also conditions where wave energy devices, especially onshore or near shore, can cause negative impacts like coastal erosion. Therefore, it is important to evaluate the environmental impact on a case-by-case basis.

Employment

For Europe, it is estimated that a target of 100 GW ocean energy (which includes wave energy) would lead to 400,000 jobs by 2050. This could imply that potentially 4000 jobs are created per GW of ocean energy development. [10]

Research and development

Wave energy technology has been under development since 1970. However, despite hundreds of different projects there is yet to be a convergence towards an industry accepted commercially viable design. Therefore, this would still be classified as a category 2 (pioneer phase) technology. A well-recognised framework to assess the technology development with ocean energy is the Technology Readiness Levels (TRL). The European Marine Energy Centre (EMEC) is the only grid-connected test facility in the world accredited to issue TRL certification. As seen below, wave energy has only reached the TRL 5-7, that is, the demonstration phase and is yet to reach the industrial roll-out step.[1]

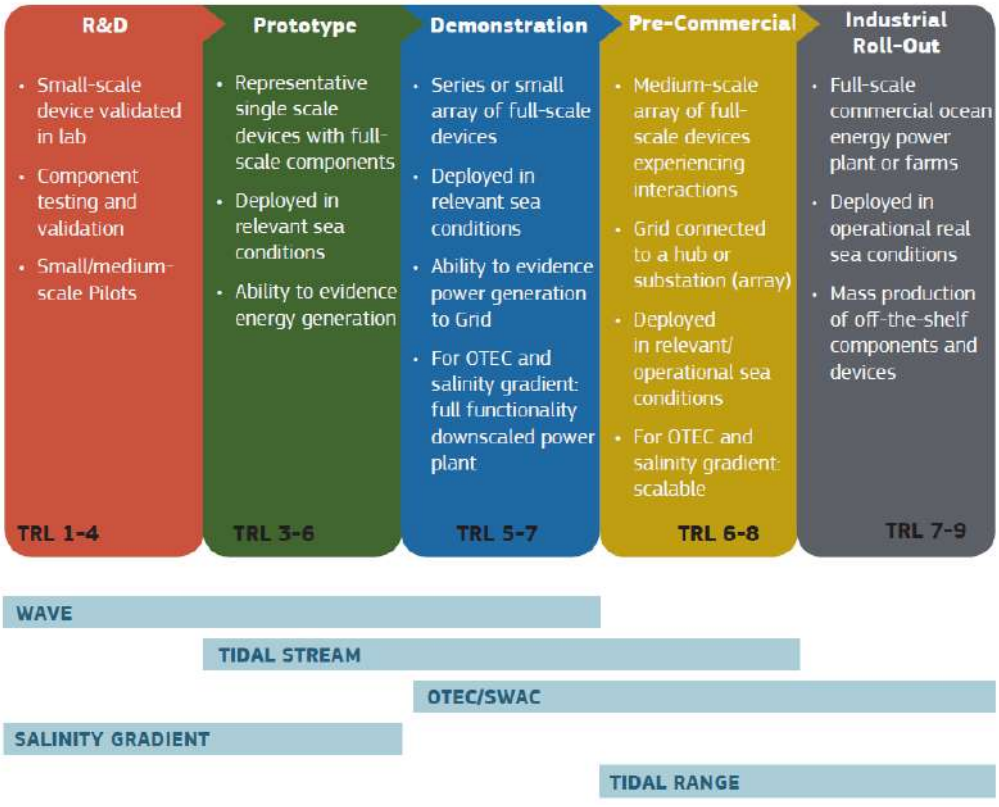


Figure 57: Where ocean energy technologies are in the stages of development [11]

However, there is a wealth of research done over the last few decades and now the development of wave energy devices is seeing a second generation of devices trying to use the learnings from the first generation and improve upon them by increasing output and reducing costs. To do so, they make use of different materials, artificial intelligence, and other innovative solutions for optimal design. This is applicable for all parts of the system like the collectors, power-take-off, mooring and the control systems. Some interesting projects in this regard are discussed here:

WaveNET: The wave net is a multiple point absorber that allows power capture from 5 of the 6 degrees of freedom of wave energy: pitch, roll, heave, surge and sway. Innovation is centred around the Squid units, composed of central riser tube connected to 3 buoyancy floats by linking arms, where the connections between each of these components is made by 6 identical, and fully articulated pumping modules. The rotating movement is converted into hydraulic power. Interlinked WaveNET units react against the rest of the array to deliver non-linear yield improvements as array dimensions increase. The Squid generating units feature a patented pumping module design, which avoids the use of mechanical end-stops. [12]

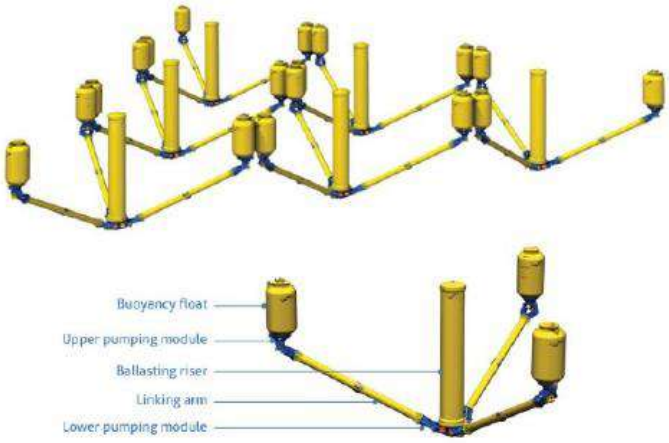


Figure 58: WaveNET [12]

Some of the second-generation collector devices are exploring new materials that allow a direct conversion of the wave energy to electricity. One such project is SBM S3, an innovative wave energy converter that features direct energy conversion from waves to electricity by means of electro active polymers. Electro-active polymers generate electricity once the membrane forming the converter is excited at the passing of waves. The flexible floater and its mooring system require minimum maintenance.[12] A similar approach of using dielectric elastomers for direct conversion is being used for power-take-off devices.

TAOIDE is an EU funded R&D project (H2020) developing a direct drive permanent magnet generator capable of operating in a fully flooded condition. To provide reliable electrical generation it is critical to develop a generator that can withstand water intrusion. The design comprises a fully-seawater flooded, “wet-gap” generator, capable of continuous and reliable operation in a marine environment. This design will maintain operability due to encapsulated rotors and windings. Such a “wet gap” generator will enhance generator longevity, decrease repair times, and increase system availability.[12]



Figure 59: Device part of the TAOIDE project.[12]

For the mooring system as well, projects are being developed with innovative designs and materials allowing for better power conversion and survivability. One such proposed technology is the taut mooring system. It is usually connected directly or incorporated within the PTO of relatively small devices so that the forces on the mooring line are translated into energy captured.[12]

While these developments are improving wave energy conversion, key aspects also being looked at are reduction of costs, longer operation time and developing devices that can easily be manufactured at large scale.

Investment Cost:

There is a big spread in investment costs when it comes to wave power plants. As a technology that has been under development for several decades, a substantial cost reduction can be expected. However, seeing that so far, the global capacity of wave energy is ~23 MW, higher cost reductions are yet to be seen along with a higher capacity rollout.

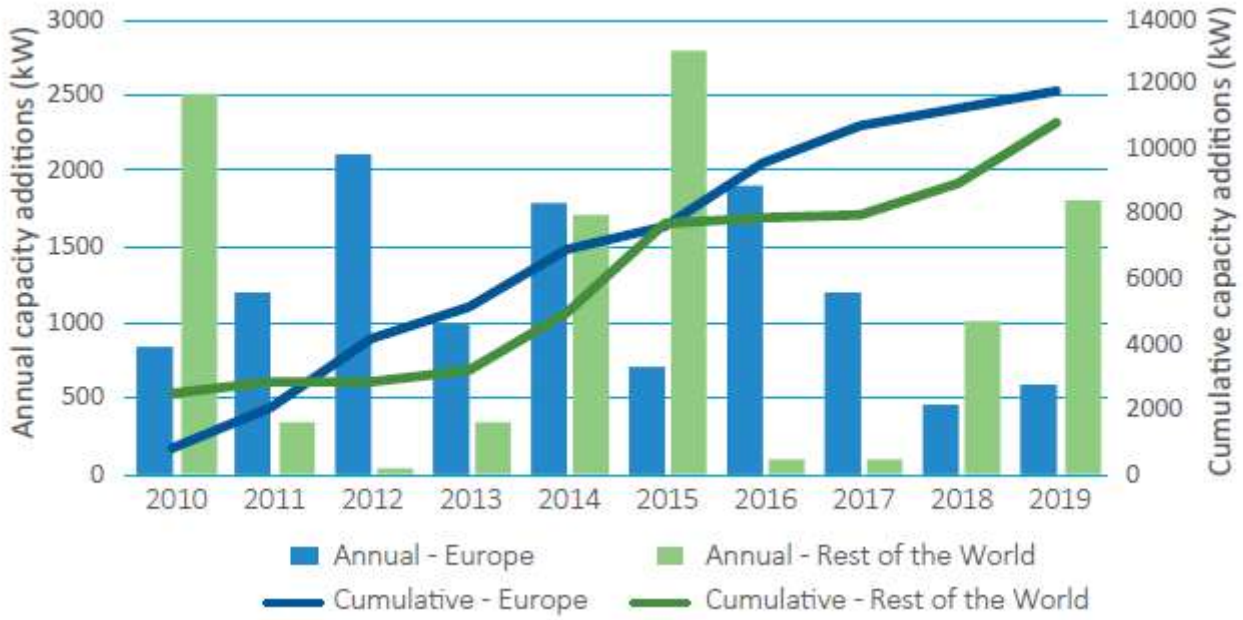


Figure 60: Installed and cumulative global wave energy capacity [10]

The learning rate approach is not applicable here as the installed capacity is low. Therefore, an empirical approach is followed here and relevant price ranges are taken into account. The recommended investment costs are based on a report by IEA Ocean Energy Systems (OES) on global ocean energy costs, and a study by Intelligent Energy Systems (IES) and Mekong Economics (MKE) on Alternatives for Power Generation in the Greater Mekong Sub-Region, focusing on Vietnam.

Investment costs [MUSD2019/MW]		2020	2030	2050
New Catalogue (2021)		10.8	8.6	5.5
IEA OES [13]	11.4 (1st array) 9.7 (2nd Array) 6 (commercial)			
Vietnam (IES, MKE) SES Scenario [14]		10.1 (2015)	7.4	4.9

Since wave energy is still at the pre-demonstration or demonstration level, it can be expected that cost will stay

higher at least for the coming decade. But with time, increased deployment and policy support, the technology can become commercially viable and the cost can drop significantly by 2050. Moreover, the cost can also be influenced by the synergies with offshore wind, tidal stream and the offshore oil and gas industries. It is important to factor in the uncertainty of the costs, and that is given in the datasheet.

Examples of projects

As the technology is still in the pre-commercial stage, most of the projects are either pilots or demonstration projects for research and development. An example of one such project is:

The Sotenäs Wave Power Demonstration Project on the west coast of Sweden included 36 wave energy converters (~1 MW total capacity), a marine substation and an almost 10 km long transmission link between the wave power park and the mainland grid. In 2015, the low voltage marine substation was connected to the Nordic grid which was heralded as the first ever grid connected subsea generator switchgear. In 2016, generated electrical power was sent to the Nordic power grid for the first time. As a part of the project effort went in to adapting the production of wave energy converters for efficient manufacture. Parameters for choice of both materials and processes included series production, quality control, cost-efficiency, environmental friendliness, and ease of manufacture. The project also involved the testing of a number of different installation techniques. Installation using a specialized Light Construction Vessel (LCV) proved the safest and most cost-effective method as it allowed for more equipment installed and connected per trip. At an installation depth of 50 meters, the use of a ROV (Remotely Operated Underwater Vehicle) was preferable to using divers. While there were discussions on expansion of this project, the plan has since been cancelled.[15]

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Data sheets

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

Technology	Wave power								
US$2019	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	0.2	0.2	0.2	0.1	0.5	0.1	0.5	A	4
Generating capacity for total power plant (MWe)	<1	5	25	<1	3	2	75	B	1,4
Electricity efficiency, net (%), name plate	80%	80%	80%	55%	95%	55%	95%	C	3
Electricity efficiency, net (%), annual average	80%	80%	80%	55%	95%	55%	95%	C	3
Forced outage (%)	10%	8%	4%	2%	15%	2%	5%		1,2
Planned outage (weeks per year)									
Technical lifetime (years)	10	15	25	5	15	20	30		4
Construction time (years)	3	3	3	2	4	2	4		4
Space requirement (1000 m^2/MWe)									
Additional data for non-thermal plants									
Capacity factor (%), theoretical	30%	32%	38%	20%	40%	30%	45%	A	1,2,3
Capacity factor (%), incl. outages	30%	32%	38%	20%	40%	30%	45%	A	1,2,3
Ramping configurations									
Ramping (% per minute)	-	-	-						
Minimum load (% of full load)	-	-	-						
Warm start-up time (hours)	-	-	-						
Cold start-up time (hours)	-	-	-						
Environment									
PM 2.5 (gram per Nm^3)	0	0	0						
SO_2 (degree of desulphuring, %)	0	0	0						
NO_X (g per GJ fuel)	0	0	0						
CH_4 (g per GJ fuel)	0	0	0						
N_2O (g per GJ fuel)	0	0	0						
Financial data									
Nominal investment (M$/MWe)	10.8	8.6	5.5	4.1	18.6	2.7	9.3		1,5,7
- of which equipment (%)	87	87	87	85	90	85	90		1,6
- of which installation (%)	13	13	13	10	15	10	15		1,6
Fixed O&M ($/MWe/year)	494,000	309,000	232,000	144,000	845,000	72,000	391,000		1,5
Variable O&M ($/MWh)									
Start-up costs ($/MWe/start-up)									
Technology specific data									

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5 Ernst & Young, “Cost of and financial support for wave, tidal stream and tidal range generation in the UK”, 2010.

6 Carbon Trust, Future Marine Energy, 2010

7 Intelligent Energy Systems (IES) and Mekong Economics (MKE), Alternatives for Power Generation in the Greater Mekong Sub-Region, 2014

Notes:

A Many different types of converters and system designs are being researched and tested, and the industry has not converged on a specific design.

B Number of small units are combined to setup a large wave farm. With time it can be expected to have larger unit sizes and also large wave farm configurations.

C Depends on the power-take-off system. Many configurations are being explored and that is why there is a wide range.

11. BIOMASS POWER

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 for power generation purposes.

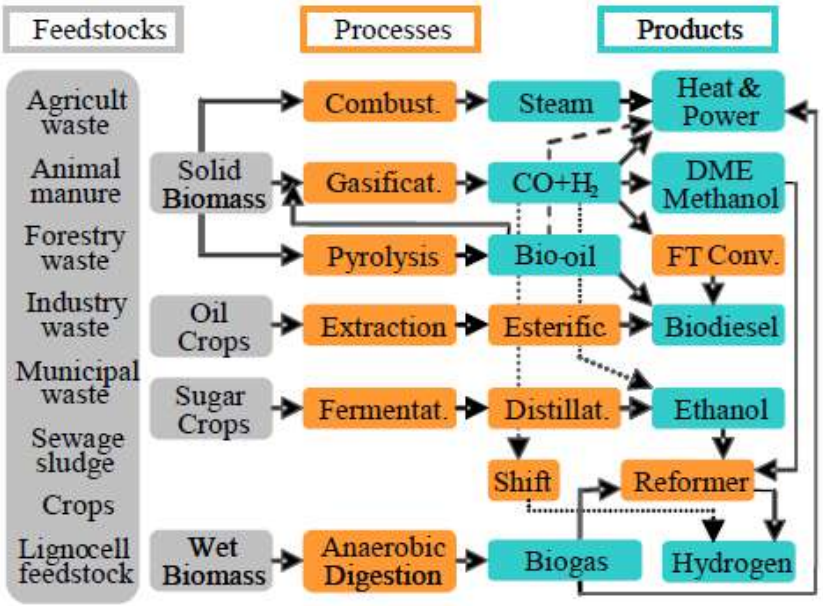


Figure 61: Biomass conversion paths (ref. 1)

The technology used to produce electricity in biomass power plants depends on the biomass resources. Due to the lesser calorific 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. Among these, the most popular are bagasse power plants with 378MW operating in cogeneration for sugar factories and generating electricity to the grid. Some large bagasse power plants are An Khe Power Plant (95 MW) in Gia Lai, KCP Phu Yen (30 MW), etc. Besides, as a country developing agriculture and forestry, Vietnam also has a great potential of rice husk and wood power sources with about 100 MW of rice husk power and 70 MW of wood power which are being prepared for investment according to the Draft National Energy Master Plan for the period 2021-2030 prepared by the Institute of Energy.

Municipal waste is treated in a separate chapter of this technology catalogue.

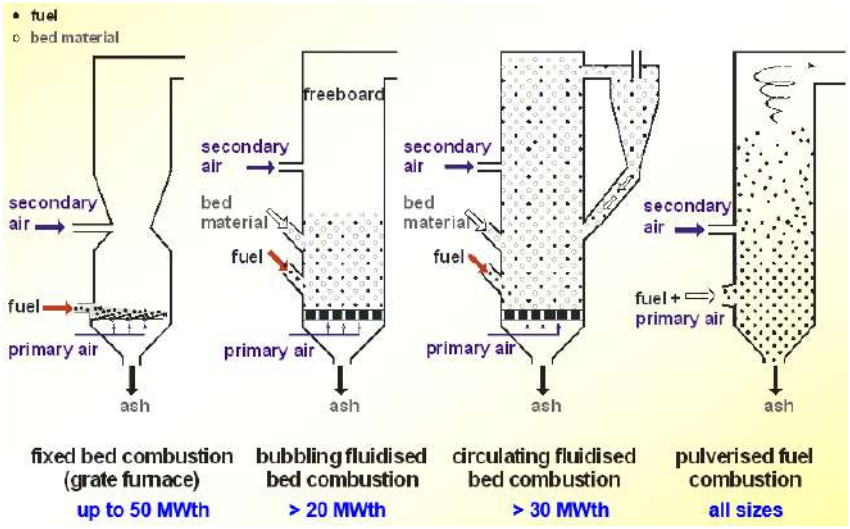


Figure 62: Technologies for industrial biomass combustion (ref. 4)

Table 18: Heating values of different biomass fuel types (ref. 9)

Type	LHV (GJ/ton)	Moisture (%)	Ash (%)
Bagasse	7.7 – 8.0	40 – 60	1.7 – 3.8
Cocoa husks	13 – 16	7 – 9	7-14
Coconut shells	18	8	4
Coffee husks	16	10	0.6
Cotton residues			
- Stalks	16	10 – 20	0.1
- Gin trash	14	9	12
Maize			
- Cobs	13 – 15	10 – 20	2
- Stalks			3 – 7
Palm-oil residues			
- Empty fruit bunches	5.0	63	5
- Fibers	11	40	
- Shells	15	15	
Debris	15	15	
Peat	9.0 – 15	13 – 15	1 – 20
Rice husks	13	9	19
Straw	12	10	4.4
Wood	8.4 – 17	10 – 60	0.25 – 1.7

The table above shows that the caloric values of the biomass 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).

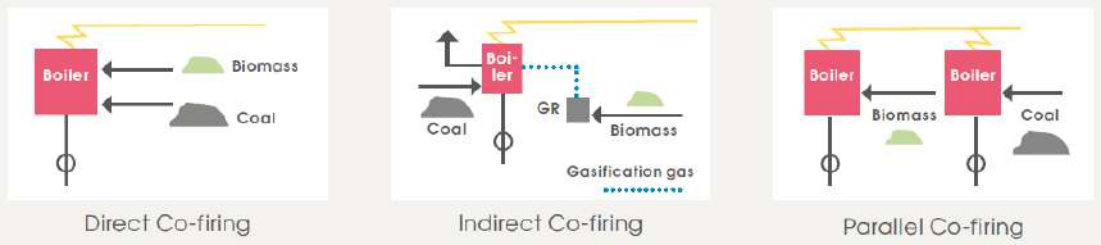


Figure 63: Different biomass co-firing configurations (ref. 6)

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 sustainable 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.
- Biomass is a limited resource and power production is in competition with other uses, e.g. transport, industry, local heating and cooking
- In the low-capacity range (less than 10 MW) the scale of economics is quite considerable.
- When burning biomass in a boiler, the chlorine and sulphur in the fuel end up in the combustion gas and erode the boiler walls and other equipment. This can lead to the failure of boiler tubes and other equipment, and the plant must be shut down to repair the boiler.
- Fly ash may stick to boiler tubes, which will also lower the boiler's efficiency and may lead to boiler tube failure. With furnace temperatures above 1000°C, empty fruit bunches, cane trash, and palm shells create more melting ashes than other biomass fuels. The level for fused ash should be no more than 15% in order to keep the boiler from being damaged. (ref. 9)
- Combustion of biomass results in emissions of SO_2, NO_x and particles.

Environment
The main ecological footprints from biomass combustion are persistent toxicity, climate change, and acidification. However, the footprints are small (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 currently increasing in Vietnam.

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 (see Figure 64 for overview of energy density of biomass). 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.

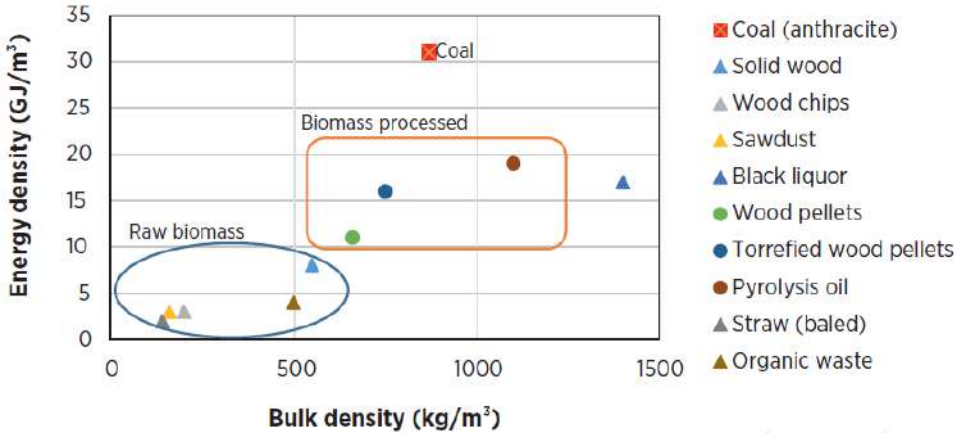


Figure 64: Energy density of biomass and coal (ref. 11).

MSW incineration, anaerobic digestion, land-fill gas, combined heat and power production based on 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 65 gives an overview of the technology maturity of different biomass production technologies.

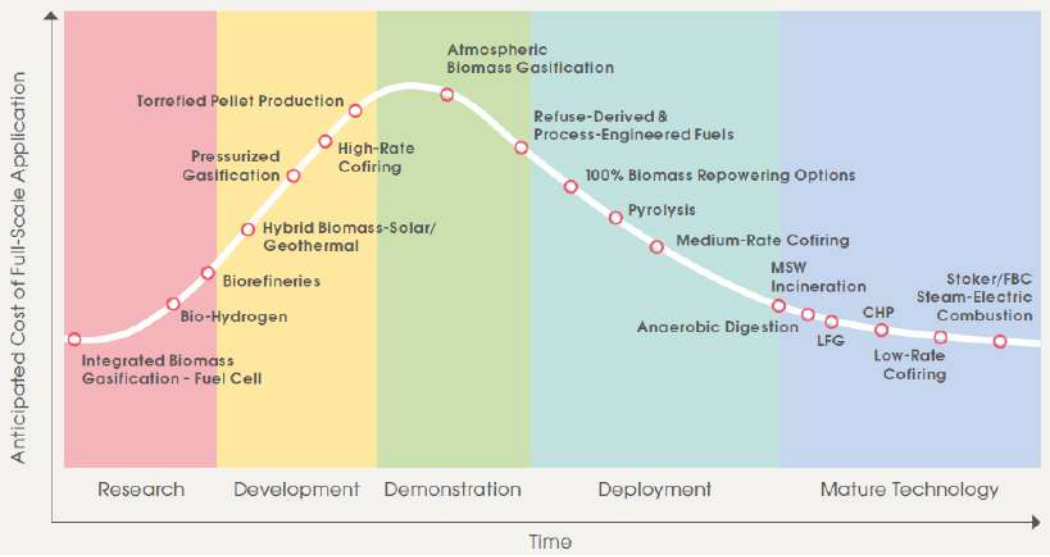


Figure 65: Biomass power generation technology maturity status (ref. 12)

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 19: Phase makeup of biomass pyrolysis products for different operational modes (ref. 13)

Mode	Conditions	Composition		
		Liquid	Char	Gas
Fast pyrolysis	Moderate temperature, short residence time	75%	12%	13%
Carbonization	Low temperature, very long residence time	30%	35%	35%
Gasification	High temperature, long residence time	5%	10%	85%

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

According to the draft National Biomass Power Development Report prepared by the Institute of Energy in 2018, it is estimated that by 2025, the total energy theory of biomass resources will reach 130.59 million tons (equivalent to 454.89 million MWh) and in 2030 will reach 138. 41 million tons (equivalent to 483.16 million MWh). Source agriculture still uses a large proportion of about 67%, followed by solar wood with about 30%, the rest is waste wood with about 3%.

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 the 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. Wastewater treatment is undertaken at a separate wastewater 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 nutshell 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.

Updated current projects:
An Khe Factory is invested by Quang Ngai Sugar Joint Stock Company, located in An Khe sugar factory in Thanh An commune, An Khe town, Gia Lai province to utilize bagasse byproducts in the sugar production process. In addition, it also takes advantage of other biomass fuel sources in the Central Highlands such as shell, coffee grounds, rice husks, sawdust and sorghum.

An Khe factory has a scale of 2 units (40 + 55) MW, officially operated from 1/2018. The plant uses stoker fired boiler technology and the steam condensate turbine (unit 55 MW has steam extraction valve fed to the degassing process). Boiler parameters: 100 bar superheated steam pressure and 540^0C superheated steam temperature. Fuel for the plant is about 600,000 tons of biomass / year, of which bagasse accounts for about 90% and other fuels account for about 10%. The electricity supplied to the power system in 2018 was 172 million kWh and in 2019 it was 147 million kWh. The total land area of the project is about 5 ha. The plant uses an electrostatic dust removal system (ESP) to reduce dust emissions.

The total investment of An Khe biomass plant was 102.8 million $ (converted to $2019, the administration, consultancy, project management, site preparation cost, the taxes and interest during construction are not included), corresponding to a nominal investment of 1.08 M$/$MW_e$. The total capital (include these components) was 107 million $, corresponding to 1.13 M$/MW. Fixed and variable O&M cost of plant is 29,000 $/MW/year and 2.9 $/MWh respectively.

Below are some key data for two examples of biomass fired plants in $2019.

Key parameter	Vietnamese case 1: KCP Phu Yen	Vietnamese case 2: An Khe
Generating capacity for one unit (MW_e)	30	40 + 55
Generating capacity for total power plant (MW_e)	60	95
Electricity efficiency, net (%), name plate	33.1	33.8
Electricity efficiency, net (%), annual average	28.2	29.0
Ramping (% per minute)	6.5	-
Minimum load (% of full load)	75	-
Warm start-up time (hours)	6	2
Cold start-up time (hours)	8	8
Emission $PM_{2.5}$ (mg/Nm^3)	100	50
SO_2 (mg/Nm^3)	0	0
NO_X (mg/Nm^3)	-	-
Nominal investment (M/MW_e$)	1.0	1.08
Fixed O&M ($/$MW_e$/year)	-	29,000
Variable O&M ($/MWh)	-	2.9
Start-up costs ($/$MW_e$/start-up)	-	-

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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 2019.

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)**								
US$2019	**2020**	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data				**Lower**	**Upper**	**Lower**	**Upper**		
Generating capacity for one unit (MWe)	25	25	25	1	50	1	50		1;5
Generating capacity for total power plant (MWe)	25	25	25	1	50	1	50		1;5
Electricity efficiency, net (%), name plate	32	32	32	25	35	25	35		1;3;7
Electricity efficiency, net (%), annual average	31	31	31	25	35	25	35		1;3;7
Forced outage (%)	7	7	7	5	9	5	9	A	1
Planned outage (weeks per year)	6	6	6	5	8	5	8	A	1
Technical lifetime (years)	25	25	25	19	31	19	31	A	8;7
Construction time (years)	2	2	2	2	3	2	3	A	7
Space requirement (1000 m^2/MWe)	35	35	35	26	44	26	44	A	1;9
Additional data for non-thermal plants									
Capacity factor (%), theoretical	-	-	-	-	-	-	-		
Capacity factor (%), incl. outages	-	-	-	-	-	-	-		
Ramping configurations									
Ramping (% per minute)	10	10	10						3
Minimum load (% of full load)	30	30	30						3
Warm start-up time (hours)	0.5	0.5	0.5						3
Cold start-up time (hours)	10	10	10						3
Environment									
PM 2.5 (mg per Nm^3)	12.5	12.5	12.5						3
SO_2 (degree of desulphuring, %)	0.0	0.0	0.0						3
NO_X (g per GJ fuel)	125	125	125						3
Financial data									
Nominal investment (M$/MWe)	1.8	1.6	1.4	1.3	2.2	1.1	1.8	B	4-8;10
- 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 ($/MWe/year)	49,500	45,500	39,600	37,100	61,900	29,700	49,500	A	4;5;8;10
Variable O&M ($/MWh)	3.2	2.9	2.5	2.4	4.0	1.9	3.2	A	5;10
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"

2 ASEAN Centre of Energy, 2016, "Levelised cost of electricity generation of selected renewable energy technologies in the ASEAN member states".

3 Danish Energy Agency and COWI, 2017, "Technology catalogue for biomass to energy".

4 IRENA, 2015, "Renewable power generation cost in 2014"

5 IFC and BMF, 2017, "Converting biomass to energy - A guide for developers and investors".

6 OJK, 2014, "Clean Energy Handbook for Financial Service Institutions", Indonesia Financial Service Authority.

7 IEA-ETSAP and IRENA, 2015, "Biomass for Heat and Power, Technology Brief".

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

9 India Central Electricity Authority, 2007, "Report on the Land Requirement of Thermal Power Stations".

10 Learning curve approach for the development of financial parameters.

Notes:

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

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

12. MUNICIPAL SOLID WASTE AND LAND-FILL GAS POWER

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 furnace (typically grate fired but could also be of the BFB or CFB type) 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. Also, a storage area for the waste is often part of the WtE power plant.

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. The main principle is similar to the one used in coal or biomass combustion power plants. 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 20: 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.

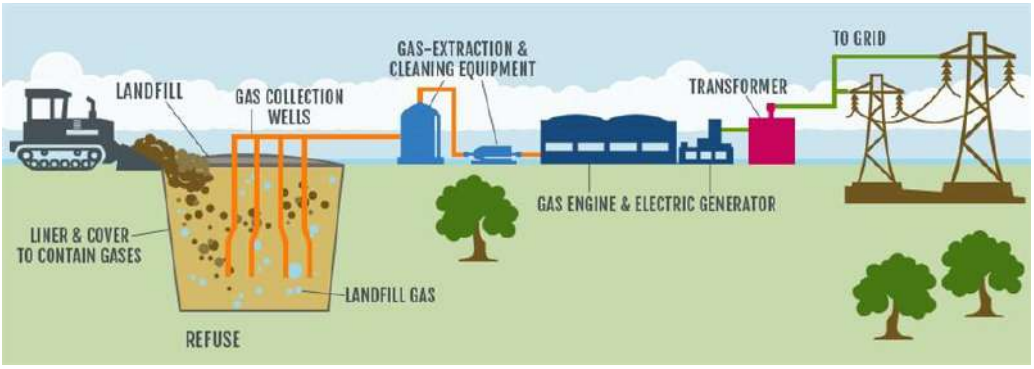


Figure 66: Land-fill gas to energy (ref. 5).

The figure below summarizes the suitability of each technology to selected waste streams from Municipal, Agricultural and Industrial sources. The basic outputs of each technology are also given in terms of electricity, heat, biogas, digestate, syngas and other commercial solids.

CONVERSION TECHNOLOGIES		Anaerobic digestion	Landfill gas recovery	Incineration	Gasification	Pyrolysis
WASTE STREAMS						
Municipal or industrial	Food waste	🟢	🟢	🟡	🟡	🟡
	Garden and park waste	🟢	🟢	🟡	🔴	🔴
	Dry recoverable waste	🔴	🔴	🟢	🟢	🟢
	Refuse Derived Fuel	🔴	🔴	🟢	🟢	🟢
	Inert	🔴	🟢	🔴	🔴	🔴
	Hazardous	🔴	🔴	🟡	🔴	🔴
	Solid Recovered Fuel	🔴	🔴	🟢	🟢	🟢
Agricultural	Biomass	🟢	🟢	🟡	🟡	🟡
	Animal waste	🟢	🟢	🟡	🟡	🟡
	Dry recoverable waste	🔴	🔴	🟢	🟢	🟢
	Hazardous	🔴	🔴	🟡	🔴	🔴
OUTPUTS						
Electricity		X	X	X	X	X
Heat		X	X	X	X	X
Biogas		X	X			
Digestate		X				
Syngas					X	X
Other commercial solids				X	X	X

Key: 🟢 Directly suitable 🟡 Likely to require pre-treatment 🔴 Unsuitable

Figure 67: Summary of waste to energy technologies' suitability per waste stream and potential output (ref. 4)

Input

MSW and other combustible wastes, water and chemicals for flue gas treatment, gasoil or natural gas for auxiliary burners (if installed), and in some cases biomass 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 ºC) or warm (<110 ºC)

water, bottom ash (slag), residues from flue gas treatment, including fly ash. If the flue gas is treated by wet methods, there may also be an output of treated or untreated process wastewater (the untreated wastewater originates from the 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 are 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 for landfill are reduced.
- Reduction of other electricity generation.
- Reduction of waste going to landfills.
- Avoidance of disposal costs and landfill taxes.
- Use of by-products as fertilizers.
- Avoid or utilisation of methane emissions from landfills.
- Reduction in carbon emitted.
- Domestic production of energy.
- The ash produced can be used by the construction industry.
- Incineration also eliminates the problem of leachate that is produced by landfills.

Disadvantages:
- Incineration facilities are expensive to build, operate, and maintain. Therefore, incineration plants are usually built for environmental benefits, instead of for power generation reasons.
- Smoke and ash emitted by the chimneys of incinerators include acid gases, nitrogen oxide, heavy metals, particulates, and dioxin, which is a carcinogen. Even with controls in place, some remaining dioxin still enters the atmosphere.

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)

The following two tables show some of the characteristics of the different conversion technologies.

Table 21: 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 22: 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 (Ha Noi)

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.

Can Tho waste incineration power plant (Can Tho city)

Can Tho waste incineration power plant is located in Truong Xuan commune, Thoi Lai district, Can Tho city has been in operation since December 2018, with a waste treatment capacity of 400 tons/day and a power generation capacity of 7.5 MW. The project has a total investment of over 1,000 billion VND, equivalent to 6.08 million USD_{2019} / MW.

Soc Son waste incineration power plant (Ha Noi)

The Soc Son waste incineration power plant in Nam Son waste treatment area, Soc Son district, Hanoi, planned to operate in 2021, has a capacity of handling 4000 tons of waste / day with a generating capacity of 75 MW. The plant has a total investment of about 7,000 billion VND, equivalent to about 4.12 million USD_{2019} / MW.

Go Cat Land fill gas power plant (Ho Chi Minh city)

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 the 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.

Data estimates (Ref. 14)

Parameters	Can Tho waste incineration power plant (Can Tho)	Cu Chi waste incineration power plant (Ho Chi Minh City)	Tram Than waste incineration power plant (Phu Tho)	Hau Giang waste incineration power plant (Hau Giang)	Soc Son waste incineration power plant (Hanoi)	Technology Catalogue 2019 (mil USD2019/ MW)	Technology Catalogue 2021 (mil USD2019/ MW)
Waste treatment capacity (ton/day)	400	2000	1000	600	4000		
Generation capacity (MW)	7.5	30	18	12	75		
Investment cost (mil USD2019/ MW)	6.08	4.67	5.05	4.54	4.12	9.1	5.6

References

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.
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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.
14. Data collected from power plants and project website.

Data sheets

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

Technology	Incineration Power Plant - Municipal Solid Waste								
US$2019	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	22	22	23						
Generating capacity for total power plant (MWe)	22	22	23						
Electricity efficiency, net (%), name plate	29	30	31	28	32	30	33	A	1
Electricity efficiency, net (%), annual average	28	29	29	26	30	28	31		1
Forced outage (%)	1	1	1						1
Planned outage (weeks per year)	2.9	2.6	2.1						1
Technical lifetime (years)	25	25	25						1
Construction time (years)	2.5	2.5	2.5						1
Space requirement (1000 m^2/MWe)	1.5	1.5	1.5						1
Additional data for non-thermal plants									
Capacity factor (%), theoretical	-	-	-	-	-	-	-		
Capacity factor (%), incl. outages	-	-	-	-	-	-	-		
Ramping configurations									
Ramping (% per minute)	10	10	10	7.5	12.5	7.5	12.5	C	1
Minimum load (% of full load)	20	20	20	15.0	25.0	15.0	25.0	C	1
Warm start-up time (hours)	0.5	0.5	0.5	0.4	0.6	0.4	0.6	C	1
Cold start-up time (hours)	2	2	2	1.5	2.5	1.5	2.5	C	1
Environment									
PM 2.5 (mg per Nm^3)									
SO_2 (degree of desulphuring, %)									
NO_X (g per GJ fuel)									
Financial data									
Nominal investment (M$/MWe)	5.6	5.2	4.6	4.1	9.4	3.4	9.4	C	1
- of which equipment (%)	59	54	50	-	-	-	-		1
- of which installation (%)	41	46	50	-	-	-	-		1
Fixed O&M ($/MWe/year)	253,400	233,700	201,200	202,700	316,700	160,900	251,500	C	1
Variable O&M ($/MWh)	25.1	24.3	23.5	18.8	29.3	17.6	29.3	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 2017- update in progress.

Notes:

A Based on experience from the Netherlands where 30 % electric efficiency is achieved. 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 calory value for waste of 9.7 GJ/ton.

Technology	Landfill Gas Power Plant - Municipal Solid Waste								
US$2019	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	1	1	1	0.5	10	0.5	10		1
Generating capacity for total power plant (MWe)	1	1	1	0.5	10	0.5	10		1
Electricity efficiency, net (%), name plate	35	35	35	25	37	25	37		2
Electricity efficiency, net (%), annual average	34	34	34	25	37	25	37		2
Forced outage (%)	5	5	5	2	15	2	15		4
Planned outage (weeks per year)	5	5	5	2	15	2	15		4
Technical lifetime (years)	25	25	25	20	30	20	30		3
Construction time (years)	1.5	1.5	1.5	1	3	1	3		3
Space requirement (1000 m^2/MWe)									
Additional data for non-thermal plants									
Capacity factor (%), theoretical	-	-	-	-	-	-	-		
Capacity factor (%), incl. outages	-	-	-	-	-	-	-		
Ramping configurations									
Ramping (% per minute)									
Minimum load (% of full load)									
Warm start-up time (hours)									
Cold start-up time (hours)									
Environment									
PM 2.5 (mg per Nm^3)									
SO_2 (degree of desulphuring, %)									
NO_X (g per GJ fuel)									
Financial data									
Nominal investment (M$/MWe)	2.6	2.6	2.6	2.4	2.9	2.4	3.0	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 ($/MWe/year)	130,000	130,000	130,000	118,100	142,900	118,100	149,400	A	3
Variable O&M ($/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%.

13. BIOGAS POWER

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 landfill. Some of the biomass potential can be converted to biogas. MSW and land-fill biogas is discussed in chapter 12.

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). The hydraulic retention time is a measure of the average length of time that a soluble compound remains in the bioreactor.

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 worldwide to produce heat and/or electricity (CHP) commercially for own use and sale to customers.

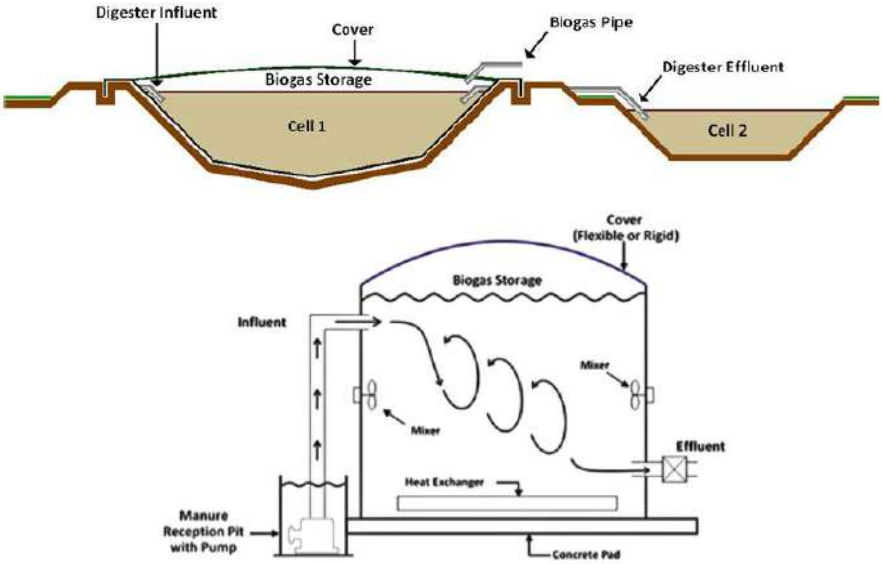


Figure 68: Covered lagoon and CSTR biogas plants (ref.3)

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).

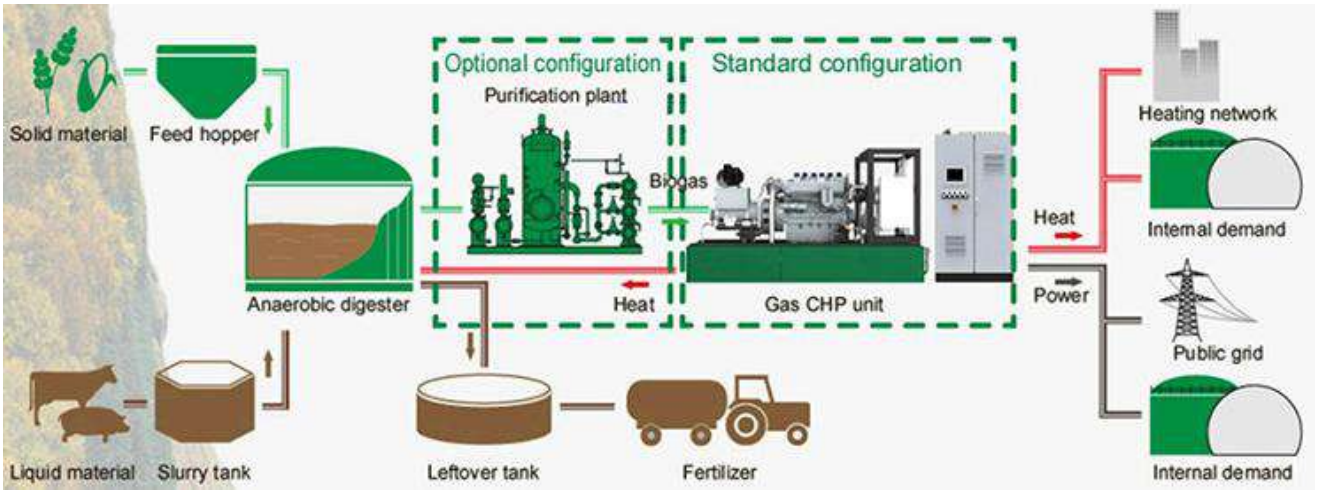


Figure 69: Biogas CHP working diagram (ref. 5).

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
Advantages
- The CO_2 abatement cost is quite low, since methane emission is mitigated, primarily from manure.
- 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.

Disadvantages

- If the plant is placed close to residential areas, smell can be a challenge.
- Leakage of methane from the biogas engine can reduce the climate gas reduction.

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).

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). This type of engine is still under development.

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 costs of biogas power plants have so far led to a limited deployment in Vietnam.

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3. IIEE, 2015. "User guide for Bioenergy Sector", *Indonesia 2050 Pathway Calculator*, Jakarta, Indonesia.
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7. Walker, 1980. "Stirling Engines", *Clarenden Press*, Oxford, London, England.
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9. Makel Engineering, 2014. "Biogas-Fuelled Hcci Power Generation System For Distributed Generation", *Energy Research and Development Division*, *Final Project Report*, California, USA.
10. PT REA Kaltim Plantations, http://reakaltim.blogspot.co.id. Accessed" 10th August 2017.
11. Industry Week. http://www.industryweek.com/energy/worlds-largest-biogas-plant-inaugurated-finland. Accessed 1st August 2017.
12. IRENA (2018): Renewable Power Generation Costs in 2017, International Renewable Energy Agency, Abu Dhabi.

Data sheets

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

Technology	Biogas power plant								
US$2019	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	1	1	1						3
Generating capacity for total power plant (MWe)	1	1	1						3
Electricity efficiency, net (%), name plate	35	35	35						4
Electricity efficiency, net (%), annual average	34	34	34						4
Forced outage (%)	5	5	5						1
Planned outage (weeks per year)	5	5	5						1
Technical lifetime (years)	25	25	25						7
Construction time (years)	1.5	1.5	1.5						7
Space requirement (1000 m^2/MWe)	70	70	70						12
Additional data for non-thermal plants									
Capacity factor (%), theoretical	-	-	-	-	-	-	-		
Capacity factor (%), incl. outages	-	-	-	-	-	-	-		
Ramping configurations									
Ramping (% per minute)	20	20	20	10	30	10	30		11
Minimum load (% of full load)	20	30	15	30	50	10	40		10
Warm start-up time (hours)									
Cold start-up time (hours)									
Environment									
PM 2.5 (mg per Nm^3)									
SO_2 (degree of desulphuring, %)									
NO_X (g per GJ fuel)									
Financial data									
Nominal investment (M$/MWe)	2.9	2.7	2.3	2.2	3.6	1.7	2.9	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 ($/MWe/year)	100,800	92,700	80,700	75,700	126,100	60,500	100,800	A	5;7;9
Variable O&M ($/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"

2 ASEAN Centre of Energy (2016). Levelised cost of electricity generation of selected renewable energy technologies in the ASEAN member states.

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6 OJK, 2014, "Clean Energy Handbook for Financial Service Institutions", Indonesia Financial Service Authority.

7 IEA-ETSAP and IRENA, 2015, "Biomass for Heat and Power, Technology Brief".

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9 Learning curve approach for the development of financial parameters.

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

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

12 Chazaro Gerbang Internasional, 2004, "Utilization of Biogas Generated from the Anaerobic Treatment of Palm Oil Mills Effluent (POME) as Indigenous Energy Source for Rural Energy Supply and Electrification - A Pre-Feasibility Study Report"

Notes:

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

14. INTERNAL COMBUSTION ENGINE

Brief technology description
Internal combustion engines (ICEs) are used in automobiles, trucks, construction equipment, marine propulsion, and backup power applications.

The basic feature of an internal combustion engine power plant is an internal combustion engine (compression ignition engine) coupled directly to a generator. Internal combustion engines can use a wide range of liquid and gaseous fuels. For power plant purposes the most common fuel is different types of oil such as crude oil, LFO, HFO, especially diesel (popularly known as diesel engine). However, in recent years gas such as natural gas/LNG or biogas has also become more widespread as fuel in internal combustion engines.

In a diesel engine 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.

In an ICE, the expansion of hot gases pushes a piston within a cylinder, converting the linear movement of the piston into the rotating movement of a crankshaft to generate power. Each movement of the piston within a cylinder is called a stroke. For power generation, four-stroke engines (intake stroke, compression stroke, power stroke and exhaust stroke) are predominately used.

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 cooled in an external cooling system. 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 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, internal combustion engine power plants using diesel are mainly used in small or medium sized power systems or as peak supply in larger power systems. For internal combustion engines using gas the fuel costs are typically lower and the engines are therefore more competitive compared to other technologies. 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 50%. Under real conditions, plant net efficiencies are 45-46%. For combined cycle power plants efficiencies of 50% are reached (ref. 5).

Input
Internal combustion 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 designed for natural gas or converted from oil to operation on natural gas.

Typical capacities
From 10 MW_e up to approx. 300 MW_e. Large internal combustion engine power plants (>20 MW_e) would often consist of multiple engines in the size of 5-23 MW_e (ref 5).

Ramping configurations
Internal 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.

Internal combustion engine 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 frequency regulation, spinning and non-spinning reserve, 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 to full load & stopping time regardless of plant size
- 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

- Internal combustion engines cannot be used to produce high-pressure steam (as turbines). Approx. 50% of the waste heat is released at lower temperatures.
- For oil/diesel fired engines:
    - Expensive fuel (for oil-fired engines)
    - High operational costs, especially for large engines
    - High environmental impact from NO_x and SO_2 emissions.
- For gas-fired engines:
    - Need to develop fuel import infrastructure (LNG) for medium-sized power plants
    - Medium-sized and large engines need to be close to the air supply, resulting in lower flexibility.

Environment

Emissions highly depend on the fuels applied, fuel type and its content of sulphur etc. 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.

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.

With SCR technology, NO_x levels of 5 ppm, vol, dry at 15% O2 can be attained (ref. 5).

Research and development

Internal combustion 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. Internal combustion engines have a potential for supplying such services, and R&D efforts are put into this (ref. 6).

Prediction of performance and cost

Internal combustion engine 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.

Internal combustion engines can 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). Other examples

include the PLTD Pesanggaran engine plant in Bali, Indonesia, a 200 MW Natural gas & HFO engine plant with 12 Wärtsilä 18V50DF engines commissioned in 2015 and the United Ashuganj, plant in Bangladesh, a 195 MW natural gas engine plant with 20 Wärtsilä 20V34SG engines commissioned in 2015 (ref. 10).

In the data sheets we consider a 100 MW_e internal combustion engine power plant consisting of 5 units, at 20 MW_e each. Although very similar in data two data sheets are added, one for oil fired and one for natural gas fired engines.

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The following sources are used:

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9. Data delivered by Wartsila, January 2021.
10. Wärtsila, 2020. Global references of internal combustion engine plants delivered by Wärtsila corporation.

Data sheets
The following pages contain the data sheets of the technology. All costs are stated in U.S. dollars ($), price year 2019. 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	Internal combustion engine (using fuel oil)								
US$2019	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	20	20	20						1
Generating capacity for total power plant (MWe)	100	100	100						
Electricity efficiency, net (%), name plate	46	47	48						1
Electricity efficiency, net (%), annual average	45	46	47	43	47	45	52		1
Forced outage (%)	3	3	3						
Planned outage (weeks per year)	1	1	1						2
Technical lifetime (years)	25	25	25						2
Construction time (years)	1.0	1.0	1.0						2
Space requirement (1000 m^2/MWe)	0.05	0.05	0.05						2
Additional data for non-thermal plants									
Capacity factor (%), theoretical	-	-	-						
Capacity factor (%), incl. outages	-	-	-						
Ramping configurations									
Ramping (% per minute)	100	100	100						8;9;10
Minimum load (% of full load)	6.0	6.0	6.0					A	1;8;9;10
Warm start-up time (hours)	0.05	0.05	0.05						1;8;9;10
Cold start-up time (hours)	0.2	0.2	0.2						8;9;10
Environment									
PM 2.5 (gram per Nm^3)	20	20	20					B; C	3;4
SO_2 (degree of desulphuring, %)	0	0	0					C	3;4
NO_X (g per GJ fuel)	280	280	280					C	3;4
Financial data									
Nominal investment (M$/MWe)	0.60	0.58	0.55	0.55	0.70	0.50	0.65	D	6;7;9;10
- of which equipment (%)									
- of which installation (%)									
Fixed O&M ($/MWe/year)	10,000	9,500	9,000						2;9;10
Variable O&M ($/MWh)	6.5	6.0	5.5						2;9;10
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 CO_2

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"

8 IRENA, Flexibility in Conventional Power Plants, 2019. https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/Sep/IRENA_Flexibility_in_CPPs_2019

9 Danish Energy Agency, 2020, "Technology Data - Generation of Electricity and District Heating"

10 Data delivered by Wartsila, January 2021.

Notes:

A 30 % minimum load per unit - corresponds to 6 % for total plant when consisting of 5 units.

B Total particulate matter

C Typical diesel exhaust emission according to Ref 3 (average of interval) unless this number exceeds the maximum allowed emission according to Minister of Environment Regulation 21/2008. Both SO_2 and particulates are dependent on the fuel composition.

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

Technology	Internal combustion engine (using natural gas)								
US$2019	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data				Lower	Upper	Lower	Upper		
Generating capacity for one unit (MWe)	20	20	20						1
Generating capacity for total power plant (MWe)	100	100	100						
Electricity efficiency, net (%), name plate	47	48	49						1;9;10
Electricity efficiency, net (%), annual average	46	47	48	44	48	46	52		1;9;10
Forced outage (%)	3	3	3						
Planned outage (weeks per year)	1	1	1						2
Technical lifetime (years)	25	25	25						2
Construction time (years)	1.0	1.0	1.0						2
Space requirement (1000 m^2/MWe)	0.05	0.05	0.05						2
Additional data for non-thermal plants									
Capacity factor (%), theoretical	-	-	-						
Capacity factor (%), incl. outages	-	-	-						
Ramping configurations									
Ramping (% per minute)	100	100	100						8;9;10
Minimum load (% of full load)	6.0	6.0	6.0					A	1;8;9;10
Warm start-up time (hours)	0.05	0.05	0.05						1;8;9;10
Cold start-up time (hours)	0.2	0.2	0.2						8;9;10
Environment									
PM 2.5 (gram per Nm^3)	7.5	7.5	7.5					B	3;4;9;10
SO_2 (degree of desulphuring, %)	0	0	0						3;4
NO_X (g per GJ fuel)	125	125	125						3;4;9;10
Financial data									
Nominal investment (M$/MWe)	0.60	0.58	0.55	0.55	0.70	0.50	0.65	C	6;7;9;10
- of which equipment (%)									
- of which installation (%)									
Fixed O&M ($/MWe/year)	10,000	9,500	9,000						2;9;10
Variable O&M ($/MWh)	6.5	6.0	5.5						2;9;10
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 CO_2

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"

8 IRENA, Flexibility in Conventional Power Plants, 2019. https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/Sep/IRENA_Flexibility_in_CPPs_2019

9 Danish Energy Agency, 2020, "Technology Data - Generation of Electricity and District Heating"

10 Data delivered by Wartsila, January 2021.

Notes:

A 30 % minimum load per unit - corresponds to 6 % for total plant when consisting of 5 units.

B Total particulate matter

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

15. GEOTHERMAL POWER

Brief technology description
This technology uses geothermal energy for power production. 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 Rankine 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 specific price.

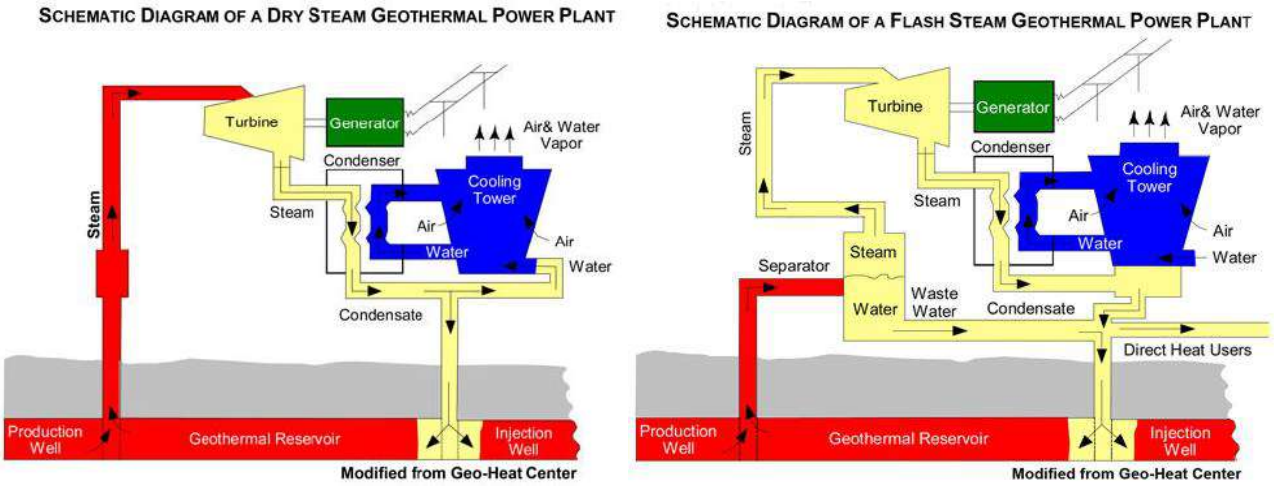


Figure 70: Direct and single flashed steam plants (ref. 7)

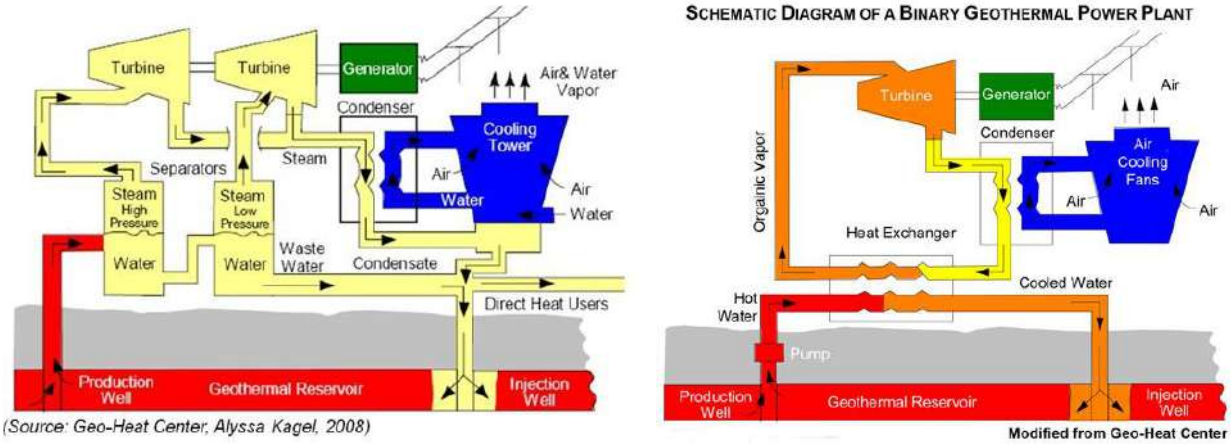


Figure 71: Double flashed and binary steam plants (ref. 7)

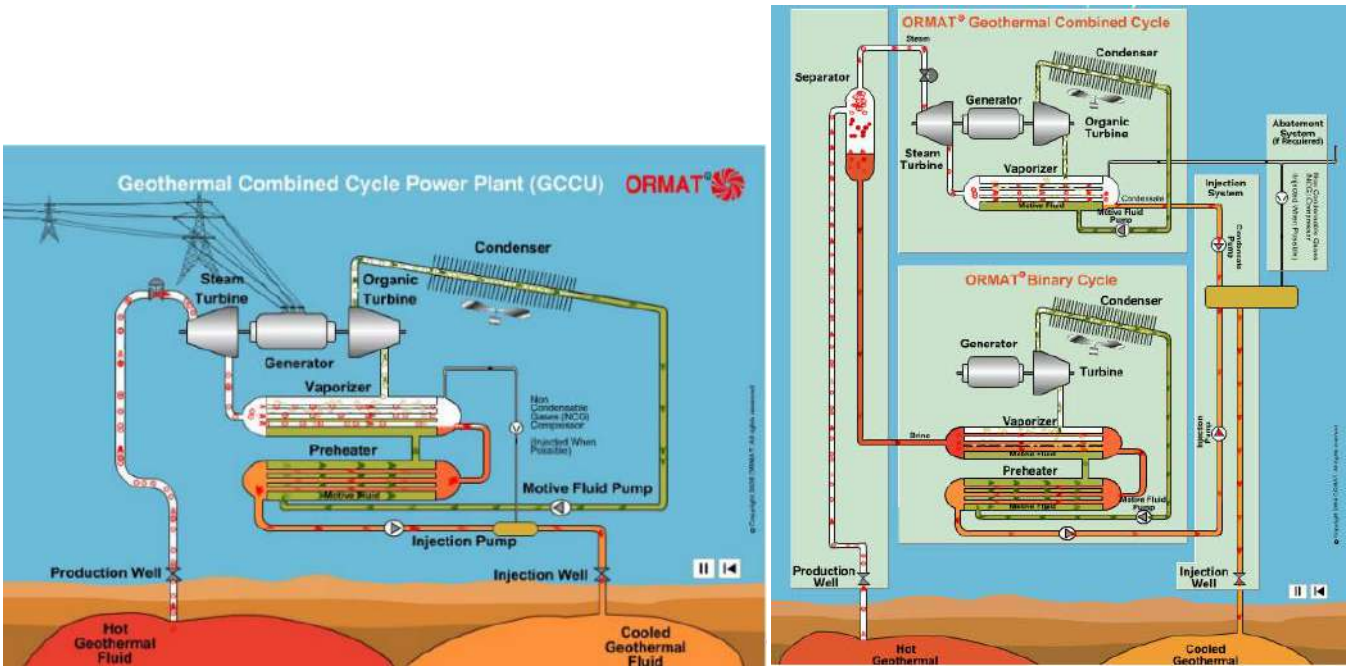


Figure 72: Hybrid/Combined Cycle plant (ref. 8)

The potential for geothermal energy in Vietnam is rather modest, and has been quantified at 3-400 MW. The geothermal resource in explored sites is of the low enthalpy type, with temperatures hardly exceeding 100 °C.

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, compared to fossil-fired base load plants.

Advantages/disadvantages
Advantages:

- High degree of availability (>98% and 7500 operating hours/annum common).
- Small ecological surface footprints.
- Comparatively low visual impact.
- Almost zero liquid pollution with re-injection of effluent liquid.
- Insignificant dependence on weather conditions.
- 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 without any fluctuations caused by weather or seasonal patterns.

Disadvantages:

- Reservoir needs to be initially tested before the plant can start stable operation (ref. 11).
- Risk of project failure/infeasibility after first explorations.
- High initial costs.
- The best reservoirs are often not located near cities.
- Need access to base-load electricity demand.
- Drilling may impact the nearby environment.
- Risk of mudslides if not handled properly.
- The pipelines to transport the geothermal fluids will have both a visual and environmental 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 H_2S 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 has 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.

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 $^{\circ}$C have been identified. Furthermore, more than 100 hot water resources with temperatures up to 148 $^{\circ}$C have been identified. Six prospect areas have already been identified: the Northwest, Northeast, Northern delta, North-central, South-central and Southern region, all of which occur in regions of recent tectonic activity. (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 have higher conversion efficiency than single flash, but can have lower efficiency than binary plants for the low enthalpy range (750-850 kJ/kg). This has a direct impact on the specific capital of the plant as shown in the following figure.

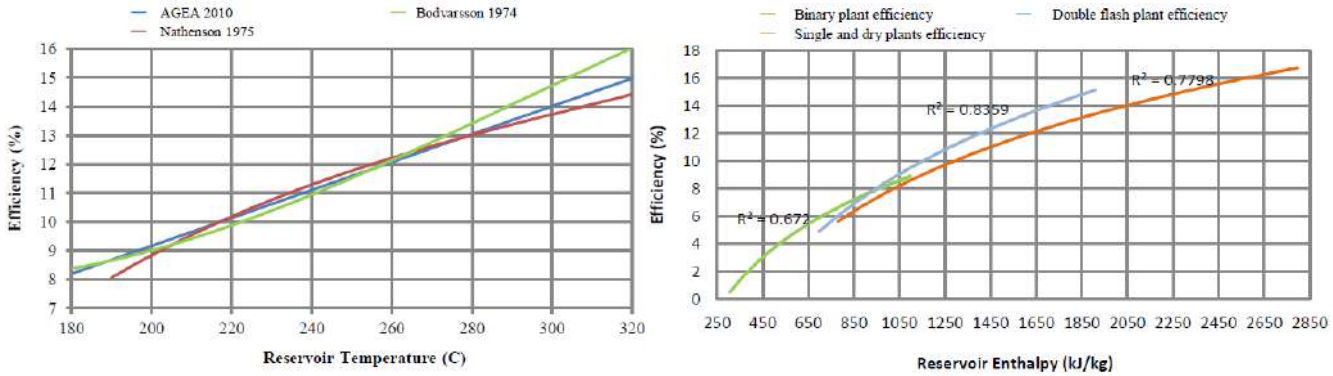


Figure 73: Geothermal plant efficiency as a function of temperature and enthalpy (ref. 5)

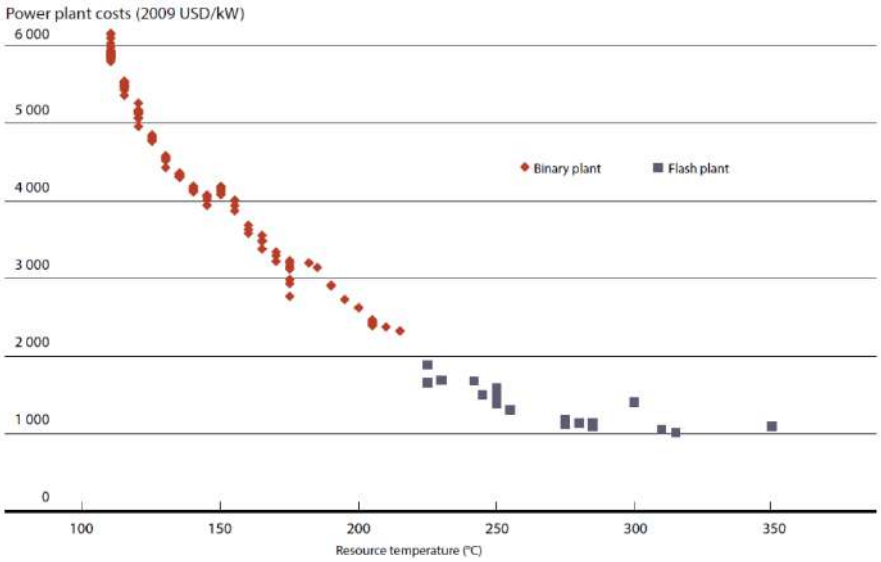


Figure 74: Indicative power plant only costs for geothermal projects by reservoir temperature (ref. 10). The power plant unit stands for around 40-50% of the total capital costs.

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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 2019.

Technology	**Geothermal power plant - small system (binary or condensing)**								
US$2019	**2020**	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data				**Lower**	**Upper**	**Lower**	**Upper**		
Generating capacity for one unit (MWe)	10	10	10	0.3	20	0.3	20		1;8
Generating capacity for total power plant (MWe)	20	20	20	5	30	5	30		1
Electricity efficiency, net (%), name plate	10	11	12	6	12	8	14	A	5
Electricity efficiency, net (%), annual average	10	11	12	6	12	8	14	A	5
Forced outage (%)	10	10	10	5	30	5	30		1
Planned outage (weeks per year)	4	4	4	2	6	2	6		1
Technical lifetime (years)	30	30	30	20	50	20	50		1
Construction time (years)	2.0	2.0	2.0	1.5	3	1.5	3		1
Space requirement (1000 m^2/MWe)	30	31	32	20	40	20	40		1
Additional data for non-thermal plants									
Capacity factor (%), theoretical	90	90	90	70	100	70	100		1
Capacity factor (%), incl. outages	80	80	80	70	100	70	100		1
Ramping configurations									
Ramping (% per minute)									
Minimum load (% of full load)									
Warm start-up time (hours)									
Cold start-up time (hours)									
Environment									
PM 2.5 (gram per Nm^3)	-	-	-	-	-	-	-	B	6
SO_2 (degree of desulphuring, %)	-	-	-	-	-	-	-	B	6
NO_X (g per GJ fuel)	-	-	-	-	-	-	-	B	6
Financial data									
Nominal investment (M$/MWe)	4.7	4.4	4.0	3.5	5.9	3.0	5.0	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 ($/MWe/year)	20,800	19,200	17,600	15,600	26,000	13,200	21,900	C;D	1;4
Variable O&M ($/MWh)	0.38	0.36	0.33	0.29	0.48	0.24	0.41	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

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 Budisulistyo & Krumdieck, 2014, "Thermodynamic and economic analysis for the pre- feasibility study of a binary geothermal power plant"

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 Climate Policy Initiative, 2015, Using Private Finance to Accelerate Geothermal Deployment: Sarulla Geothermal Power Plant, Indonesia.

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 smaller units are assumed to be binary units at medium source temperatures.

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

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

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

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

Technology	**Geothermal power plant - large system (flash or dry)**								
US$2019	**2020**	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data				**Lower**	**Upper**	**Lower**	**Upper**		
Generating capacity for one unit (MWe)	55	55	55	30	500	30	500		1
Generating capacity for total power plant (MWe)	110	110	110	30	500	30	500		1
Electricity efficiency, net (%), name plate	16	17	18	8	18	10	20	A	5
Electricity efficiency, net (%), annual average	15	16	17	8	18	10	20	A	5
Forced outage (%)	10	10	10	5	30	5	30		1
Planned outage (weeks per year)	4	4	4	2	6	2	6		1
Technical lifetime (years)	30	30	30	20	50	20	50		1
Construction time (years)	2.0	2.0	2.0	1,5	3	1,5	3		1
Space requirement (1000 m^2/MWe)	30	30	30	20	40	20	40		1
Additional data for non-thermal plants									
Capacity factor (%), theoretical	90	90	90	70	100	70	100		1
Capacity factor (%), incl. outages	80	80	80	70	100	70	100		1
Ramping configurations									
Ramping (% per minute)	3	10	20						8
Minimum load (% of full load)									
Warm start-up time (hours)									
Cold start-up time (hours)									
Environment									
PM 2.5 (gram per Nm^3)	-	-	-	-	-	-	-	C	6
SO_2 (degree of desulphuring, %)	-	-	-	-	-	-	-	C	6
NO_X (g per GJ fuel)	-	-	-	-	-	-	-	C	6
Financial data									
Nominal investment (M$/MWe)	3.6	3.4	3.1	2.7	4.5	2.3	3.8	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 ($/MWe/year)	18,700	17,400	15,800	14,000	23,400	11,900	19,800	B;D	1;4
Variable O&M ($/MWh)	0.26	0.24	0.22	0.19	0.32	0.16	0.27	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 H_2S. From Minister of Environment Regulation 21/2008 this shall be below 35 mg/Nm^3.

D The learning rate is assumed to impact the geothermal specific equipment and installation. The power plant units (i.e. the turbine and pump) is assumed to have very little development. From Ref. 3 it is assumed that half of the investment cost are on the geothermal specific equipment.

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

16. 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).

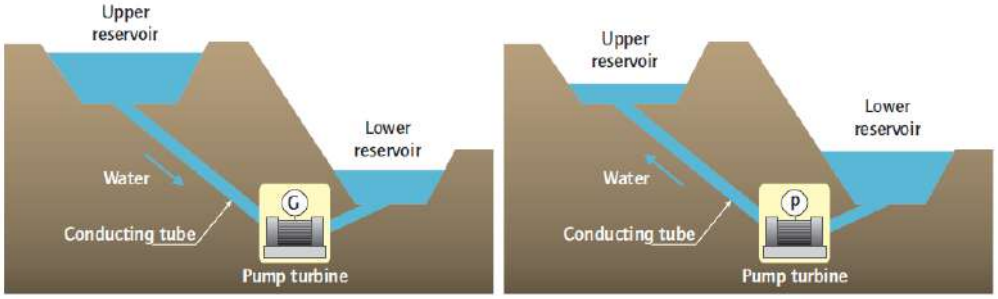


Figure 75: Pumped storage hydropower plants (ref. 2)

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).

According to *Development strategies for hydro pumped storage in Vietnam* developed by Lahmeyer International and Institute of Energy in 2016, Vietnam has nearly 10 GW potential of hydro pumped storage concentrating in the North and South-Central regions as shown in the following map:

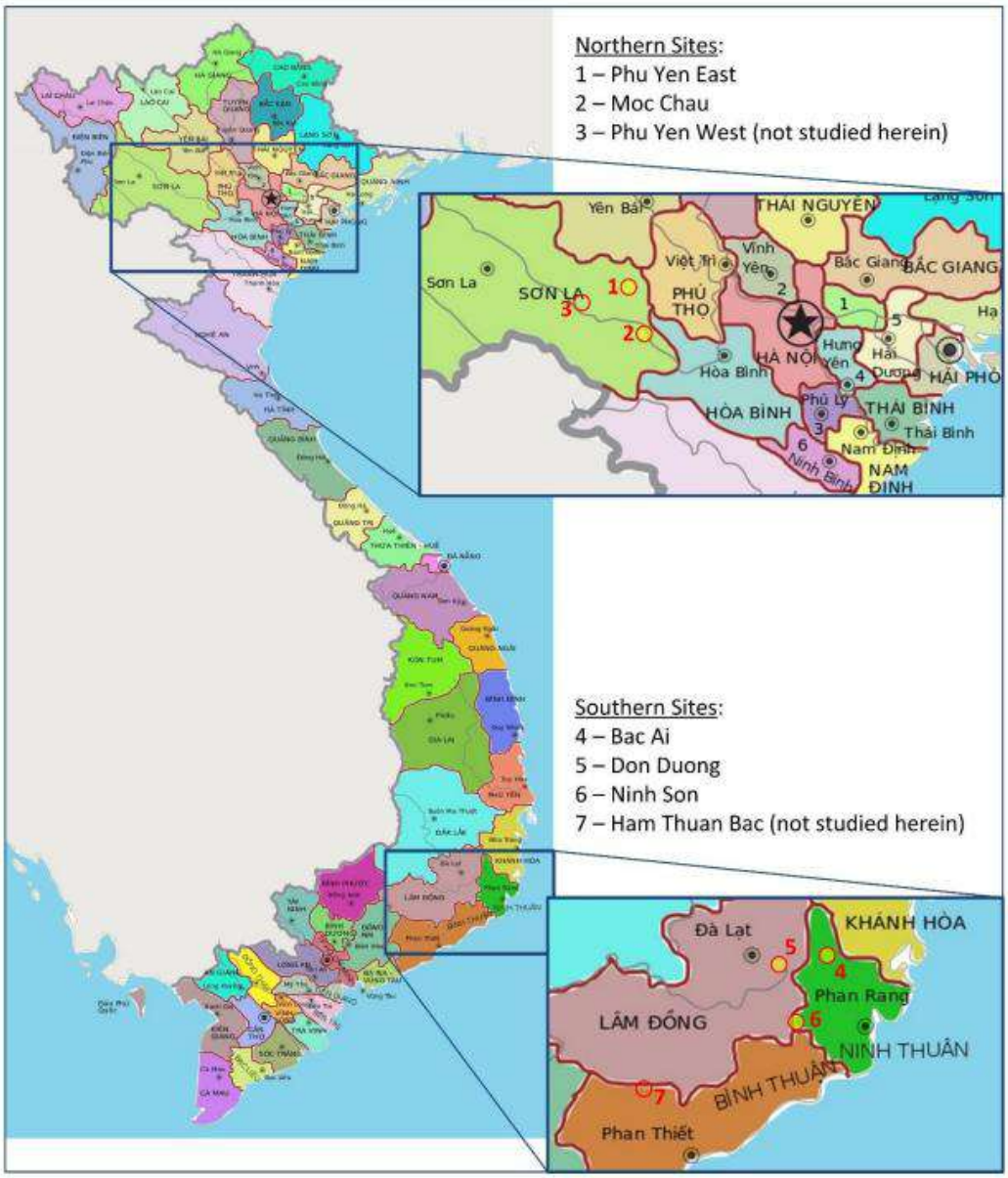


Figure 76: Map of potential locations of hydro pumped storage in Vietnam.
Source: Lahmeyer International & IE, "Development strategies for hydro pumped storage in Vietnam", 2016.

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
In Indonesia, PLN expected that the Upper Cisokan hydropower plant (pumped storage) with an installed capacity of 1040 MW would need around 3000 workers to complete.

Research and development
Hydro pumped storage is, like hydro reservoir power, a well-known and mature technology and can be classified as a category 4 technology.

Under normal operating conditions, hydropower turbines are optimized for an operating point defined by speed, head and discharge. Head is the change in water levels between the hydro intake and the hydro discharge point. It is a vertical height measured in metres. 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.

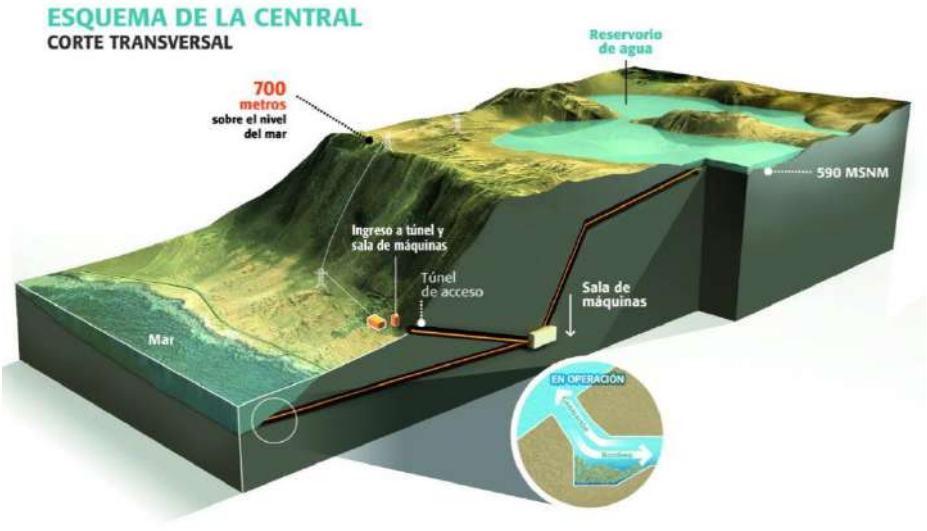


Figure 77: A 300 MW sea water pumped storage hydropower plant in Chile (ref. 13)

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 38.4 m, 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 403 m, 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 918 M$ ($2019, the administration, consultancy, project management, site preparation cost, the taxes and interest during construction are not included), equal to the investment rate of 0.77 M$/ MW_e. The total capital (including these components) was 1,019 million $, corresponding to 0.848 M$/$MW_e$ (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 of 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 3,600 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 2024.

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Data sheets

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

Technology	**Hydro pumped storage**								
US$2019	**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	70	82	70	82		1;3;5
Electricity efficiency, net (%), annual average	80	80	80	70	82	70	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$19/MWe)	0.89	0.89	0.89	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 ($19/MWe/year)	8,320	8,320	8,320	4,000	30,000	4,000	30,000		3;4;6.7
Variable O&M ($19/MWh)	1.4	1.4	1.4	0.5	3.0	0.5	3.0		1;7
Start-up costs ($/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

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Notes:

A Size per turbine.

B Uncertainty (Upper/Lower) is estimated as +/- 50%.

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

D The size of the total power plant and not per unit (turbine).

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

17. ELECTROCHEMICAL STORAGE

Brief technology description

With increasing shares of renewable energy in power systems, the grid faces variability and uncertainty in supply. Due to this, the power sector has seen a lot of growth in the role of electricity storage technologies. Some of the main technologies being looked at includes storing excess electricity using electrochemical storage batteries like lithium-ion, redox flow, lead-acid, high temperature sodium sulphur (NaS) and sodium nickel chloride. Other technologies also include fuel cells, supercapacitors, flywheels, and conversion to hydrogen. The potential applications of batteries in electricity systems are very broad, ranging from supporting weak distribution grids, to the provision of bulk energy services or off-grid solutions (see Figure 78 below).

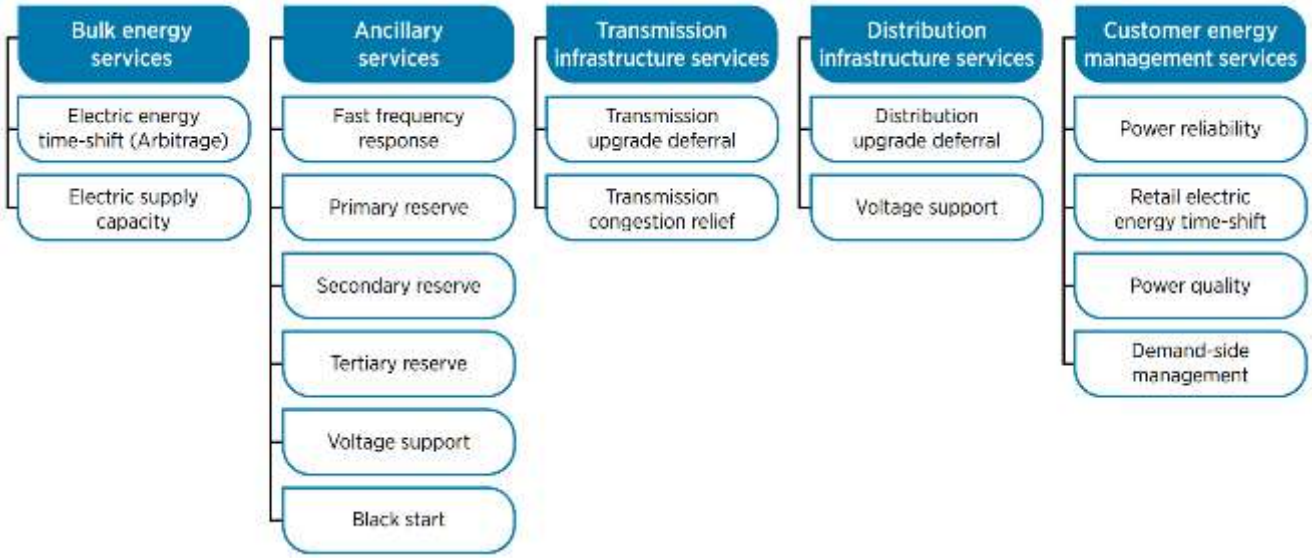


Figure 78: Range of services electricity storage can provide (ref. 41).

Among all the technologies mentioned, electrochemical storage (batteries) has experienced the most notable cost declines in the past years. This is especially true for li-ion batteries, which has been used in different grid applications around the world. As per data from IEA, in 2018, li-ion batteries made up 93% share of energy storage technology mix (excluding pumped hydropower storage). Furthermore, lithium-ion batteries (LIB) have completely dominated the market for grid scale energy storage solutions in the last years and appear to be the dominating battery solution (see Figure 79 below for the US). Due to the current importance of LIB storage in the power system, a special focus is being directed to it through this chapter; despite the catalogue being mainly for power generation technologies.

This technology description here focuses on batteries for provision of *bulk energy services* and *customer energy management services*, i.e. time-shift over several hours (arbitrage)– for example moving PV generation from day to night hours –, the delivery of peak power capacity, demand-side management, power reliability and quality.

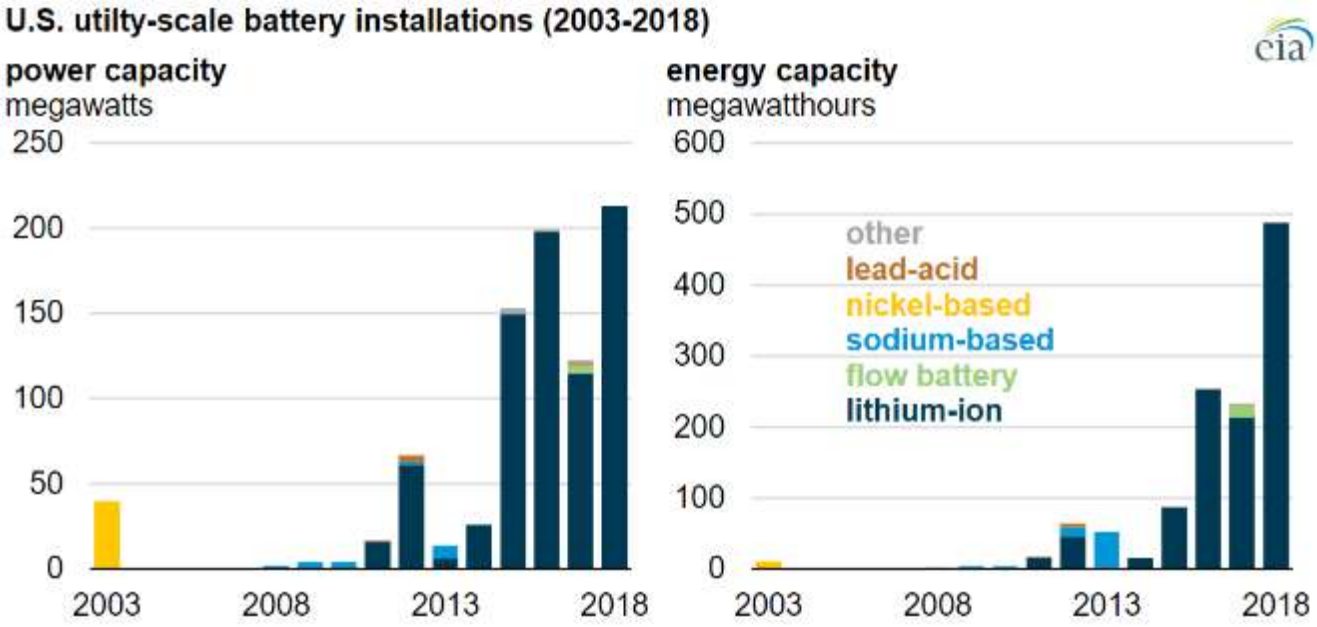


Figure 79: Utility-scale battery installations by type in the US (2003-18). Source: EIA.

A typical LIB installed nowadays has a graphitic anode, a lithium metal oxide cathode and an electrolyte that can be either liquid or in (semi-)solid-state. When liquid, it is composed of lithium salts dissolved in organic carbonates; when solid, lithium salts are embedded into a polymeric matrix. Three major types of Li-Ion batteries installed nowadays for utility-scale storage are reported in the table below. Li-Ion batteries commonly come in packs of cylindrical cells and can reach energy densities of up to 300 Wh/kg. The unit's footprint can be assumed to be around 5 m^2/MWh.

Short name	Name	Anode	Cathode	Energy density Wh/kg	Cycles	Calendar life	Major manufactures
NMC	Lithium Nickel Manganese Cobalt Oxide	Graphite	Li $Ni_{0.6}Co_{0.2}Mn_{0.2}O_2$	120-300	3000-10000	10-20 years	Samsung SDI LG Chem SK Innovation Leclanche Kokam
LFP	Lithum Iron Phosphate	Graphite	$LiFePO_4$	50-130	6000-8000	10-20 years	BYD/Fenecon Fronius/Sony*
LTO	Lithium Titanate	$LiTO_2$	$LiFePO_4$ or Li $Ni_{0.6}Co_{0.2}Mn_{0.2}O_2$	70-80	15000-20000	25 years	Leclanche Kokam Altairnano

Figure 80: Major LIB types in use for utility-scale storage (Ref. 47).

Electrons flow in the external circuit and Li ions pass through the electrolyte. The charging and discharging of the battery depend on the shuttling mechanism of Li ions between anode and cathode. This process is controlled by an electronic battery management system to optimize cell utilization and degradation, while delivering the desired loading/unloading current. The fast Li-ion transport and the small diffusion distance due to the lamellar architecture of components inside the cell ensure that the response time for LIB is very low (ref. 1). It also has a low self-discharge rate of only 0.1–0.3% per day and good cycle efficiency of up to 97% (ref. 8).

A schematic overview of a battery system and its grid connection can be seen in the figure below. A Thermal Management System (TMS) controls the temperature in the battery packs to prevent overheating and thermal

runaway (the phenomenon is explained in the following). The Energy Management System regulates the energy exchange with the grid. Power electronics convert DC into AC before power is injected into the grid. In some cases (high-voltage grids), a transformer might be required to feed electricity into the grid. Some manufacturers offer container-type storage battery modules which can be connected in series to increase the storage capacity.

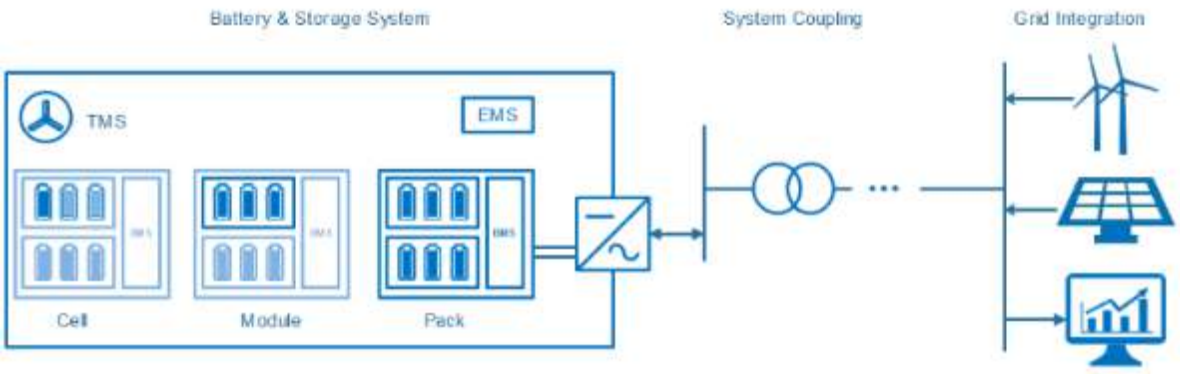


Figure 81: Schematic illustration of a battery storage system and its grid connection (Ref. 43).

Charging and discharging rates of LIB are often measured with the C-rate, which is the maximum current the battery can deliver with respect to its volume. For example, if a battery is discharged in 20 minutes, 1 hour and 2 hours then it has C-rates of 3C, C and C/2 respectively. Operations at higher C-rates than specified in the battery pack are possible, but would lead to faster degradation of the cell materials (ref. 9). Generally, for the same chemistry/construction, a battery going through a 15-minute full discharge will have a lower cycle life (and thereby lifetime) than a similar battery used for a 1-hour full discharge cycle.

LIB do not suffer from the memory effect issue (the effect of batteries gradually losing their maximum energy capacity if they are repeatedly recharged after being only partially discharged) and can be used for variable depths of discharge at short cycles without losing capacity (ref. 11). The relationship between battery volume (in MWh) and loading/unloading capacity (in MW) can be customized based on the system needs and in order to obtain a better business case.

The lifetime of battery energy technologies is better measured by the total number of cycles undergone over the lifetime. Nowadays, a Li-Ion battery typically endures around 10000 full charge/discharge cycles. Batteries generate DC current, which then needs to be converted into AC to be fed into the most interconnected grids. This is achieved through power electronics (inverters).

As mentioned at the beginning of this section, battery energy storage systems (BESS) can have manifold applications and thus can be installed at different voltage levels (see figure below). BESS architecture is ultimately shared across use types, with minor differences depending on the single applications. In off- and micro-grid contexts (not represented in the figure below), grid connection costs are reduced totally or partially.

Industry and households can install batteries behind the meter to reshape the own load curve and to integrate distributed generation such as rooftop or industrial PV. The major benefits are related to retail tariff savings, peak tariff reduction, reliability and quality of supply (ref. 43). Batteries can boost the self-consumption of electricity and back up the local grid by avoiding overload and by deferring new investments and reinforcements. In case of bi-directional flows to/from the grid (presumption), BESS can increase the power quality of distributed generation and contribute to voltage stability. In developed market settings, these functions might not only reflect requirements enforced by the regulation, but also materialize in remunerated system services.

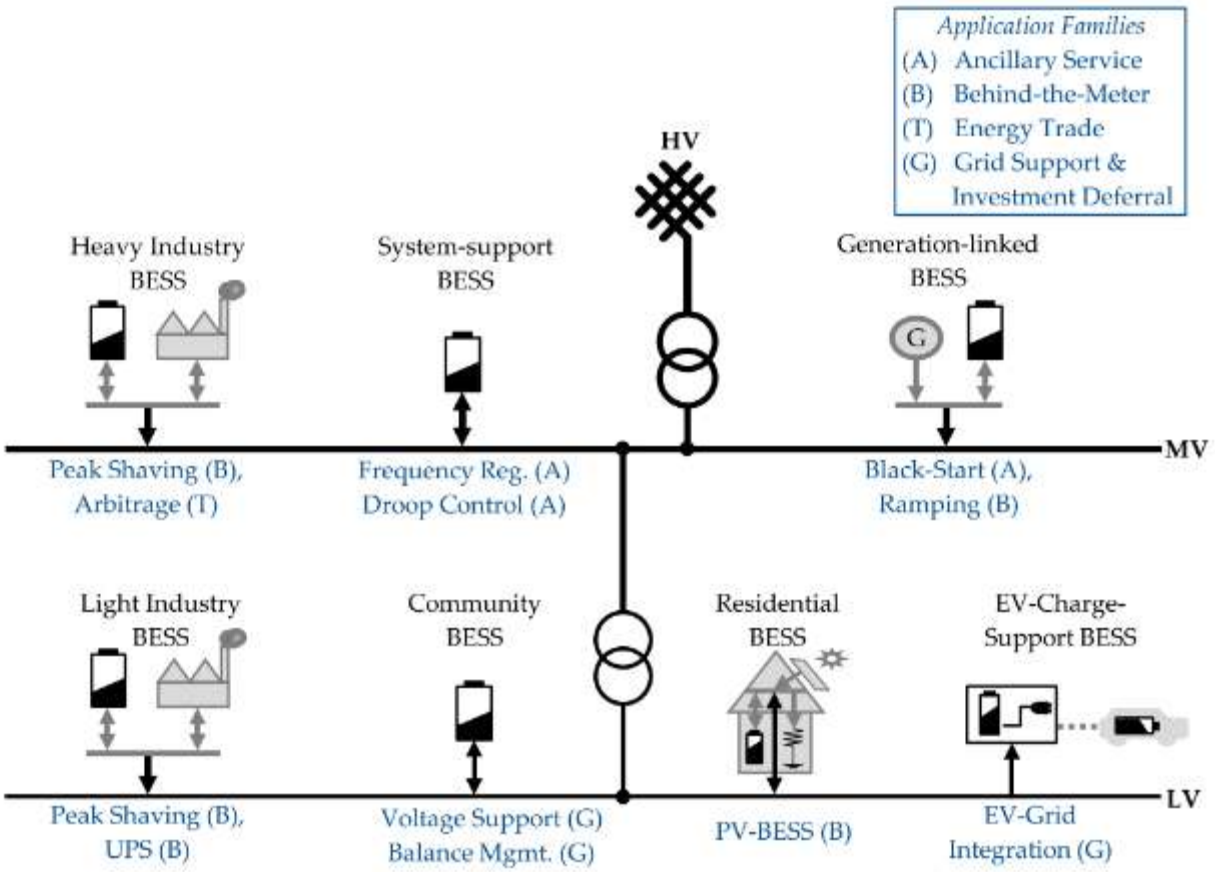


Figure 82: Different uses of battery systems depending on voltage level and application families (Ref. 43).

Input
Electricity.

Output
Electricity.

The efficiency of Li-ion battery cells is close to 100%. However, there are several sources for losses, which can be grouped into operational and stand-by losses. Operational losses are related to the power electronics and to the circuit resistance in the LIB and they increase with the second power of the current flowing in the battery's external circuit. Stand-by losses are the result of unwanted chemical reactions in the battery (*self-discharge rate*). Self-discharge rates increase with temperature but can be assumed to be in the order of 0.1% of the energy content per day.
Auxiliaries (thermal management system, energy management system) require energy to run as well, and losses therein must be accounted for as well.

AC-DC conversion and energy demand from the control electronics lead to a grid-to-grid efficiency (AC-AC) of about 90% nowadays. Frequency regulation requires fast short-cycle charge-discharge and reduces round-trip efficiency. Extensive cycling reduces the lifetime of batteries. Overall, the round-trip efficiency can be expressed as a decreasing function of the C-rate, that is how much current is released by the battery.

Typical capacities
For bulk energy services, Li-Ion batteries come in large sizes. Small batteries are in the order of MW/MWh, but can reach several hundreds of MW/MWh. For example, the Hornsdale facility in Australia has 100MW/129MWh capacity/energy components and a further expansion of 50MW/64.5MWh is in the pipeline. For distributed applications, battery size can range from a few kW to hundreds of kW.

For bulk energy services applications (for instance time shifting), several hours of storage might be needed, depending on the system needs. For example, an AES installed LIB facility in San Diego can feed the grid 37.5 MW of power continuously for 4 hours. This tendency will increase in the future with the necessity of moving variable renewable energy generation over long time frames.

Ramping configurations
Li-ion batteries (LIB) installations are very flexible in terms of power/energy capacity and time of discharge. This type of battery has a response time in the order of milliseconds (determined by the inverter), which makes it suitable for the wide range of applications mentioned before, including power quality.

Advantages/disadvantages
Advantages/disadvantages are considered in relation to other battery technologies.

Advantages:

- Li-ion batteries (LIB) modules do not need particular maintenance and can work in harsh environments, thus operational costs are contained.
- LIB have a relatively high energy and power density.
- Round-trip energy efficiency is remarkably high for LIB among commercially scalable batteries. Other batteries have an efficiency of 10% lower or more. Some batteries like NiCd/Ni-MH lose energy capacity if not fully discharged. This is called memory effect. LIB do not suffer from memory effect and have low self-discharge.
- The combination of high power and energy density and the very short response time (few milliseconds) enables the usage of LIB in both power intensive applications such as frequency regulation and energy intensive applications like time shifting of dispatch. Li-Ion batteries can therefore benefit from different revenue streams, associated with a set of system services. The lack of memory effect allows short and deep discharging.
- LIB have a relatively long lifetime (i.e. many cycles) compared to many other battery types. This strengthens the business case and the financial viability of battery storage systems, since it lowers the levelized cost of storage.

Disadvantages:
Li-ion batteries (LIB) have a relatively small number of technical disadvantages, mainly related to electrochemical reactions within the cells.

- Electrode materials are prone to degradation if overcharged and deeply discharged repeatedly. A proper management system can effectively mitigate this problem.
- Continuous cycling lowers the overall lifetime of the battery.
- Li-Ion battery systems need cooling to remove the heat released by the battery modules. The auxiliary consumption needed for cooling can be sizeable depending on the type of application and battery use. Safety issues from thermal runaway are of concern. Thermal runaway arises as a consequence of high temperatures in the battery cells; within milliseconds, the energy content in the battery is emptied out and unacceptably high temperatures are reached. Li-Ion batteries can charge in the 0-45°C temperature range, discharge even at slightly higher temperatures; thermal runaway can start already at 60°C. Overcharging is a cause of thermal runaway.
- The electrolyte has a limited electrochemical stability window. Beyond this limit, a redox reaction takes place between the oxygen released from the cathode and the electrolyte; the battery might catch fire (ref. 21). During a thermal runaway, the high thermal power released from one cell can spread to the adjacent cells, making entire modules unstable.
- Stability of cathode materials in contact with electrolyte is better for phosphate cathodes than oxide cathodes but phosphate-based batteries deliver lower potential. Thermal runaway can be suppressed using inhibitors (ref. 22).
- With LIB demand increasing exponentially every year, the supply of raw materials and incremental costs are the main concerns. Lithium extraction has the potential for geopolitical risks because the world's known

resources of easily extractable lithium are largely concentrated in three South American countries: Chile, Bolivia, and Argentina (ref. 23), but the limited availability of cobalt resources remain the biggest concern.
- The self-discharge rate and all the parasitic losses in the system become a significant source of losses at residence times beyond a few days, hence Li-Ion batteries are not advisable for long-term storage.

Environment
Some LIB contains toxic cobalt and nickel oxides as cathode materials and thus need to be meticulously recycled. At present, the market price of component materials like lithium/cobalt is still not high enough for making it economically beneficial. Unlike portable electronics, large installations help enforce recycling regulations.

Lithium resource depletion from fast adoption of LIB in electric vehicles and utility scale storage is a concern (ref. 24). US-EPA reported that across the battery chemistries, the global warming potential impacts attributable to the LIB production is substantial (including energy used during mining): the literature points at a climate impact ranging from 39 kg CO_{2eq}/kWh to 196 kg CO_{2eq}/kWh (ref. 46).

Research and development
LIB have been well-known for decades, but their use as utility-scale storage has gained momentum only in recent years. LIB moved from the pioneer phase (category 2) to the commercial phase with a significant development potential (category 3). Therefore, there is still significant potential for R&D.

Due to the economic and technological impact, a wide range of government and industry-sponsored research is taking place across the world towards the improvement of LIB at material and system level.
Higher energy density is achievable by discovering new cathode with higher electrochemical potential and anode/cathode materials, which can build in more lithium per unit volume/weight.
Higher electrochemical potential for cathode materials needs to be matched with the electrochemical stability of the electrolyte used. Thus, research in new electrolyte systems is also needed. Electrolytes with better chemical stability also lead to lower chances of thermal runaway. Improved power capacity is obtained if lithium-ion movement is faster inside the electrode and the electrolyte materials. In short, cathodes with high electrochemical potential, anodes with low electrochemical potential, cathode/anodes with high lithium capacity, electron/lithium transport, electrolytes with large electrochemical stability window and fast lithium transport are the desirable directions in LIB research.

A nickel-phosphate-based cathode can operate at 5.5 V (compared to 3.7 V of cobalt oxide cathodes), but a complementary electrolyte is not available yet (ref. 25). On the anode side, silicon-based anodes can improve upon carbon-based anodes. Stability for long-term operations has however remained an issue (ref. 26). On the electrolyte side, ionic liquids are being researched for safer high-potential operations (ref. 27).

In the future, Lithium-Air and Lithium-Sulphur batteries could reach commercialization, but challenges related to humidity, unwanted chemical reactions (production and leaking of polysulphide ions into the electrolyte in the case of Li-S batteries).

Another promising branch of research is linked to Lithium Solid-State batteries (SSBs). SSBs use a solid electrolyte instead of a liquid/gel electrolyte as in today's Li-ion batteries: this would strongly reduce flammability risks and increase the energy density of a battery pack, besides being very stable (ref. 44). The main disadvantages connected to SSBs are the high cost, poor ionic conductivity of the electrolyte, incompatibility between electrolyte and electrodes and the fast growth of lithium dendrites. This eventually leads to a poor cycle performance and a rapid capacity degradation (ref. 45).

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

LIB installations for utility operation from major companies like Samsung SDI/TESLA are modular and scalable: Costs can be assumed to increase linearly with the storage size. Modular systems that have been used by TESLA to create 80 MWh storage system within 3 months (ref. 29).
Data for the Samsung SDI model is here the main reference for technical parameters; other manufacturers are

considered to tune and compare the data.

Due to lack of specific daily discharge loss data, generally accepted information obtained from published journal articles and review papers is used as a standard (ref. 8). Unforeseen outages are very rare and can be considered not to occur, provided that good management is performed.
Samsung SDI also suggests operation between C/2 to 3C rate. A 10C-rate, long-lifetime battery (ref. 30) is under development and 20C-60C-rate batteries are being experimented (ref. 31).

Commercial units have nowadays a lifetime of about 10000 cycles (ref. 42). More stable electrode materials (e.g. polyanion cathode and titanate anode) and a better system management are set to boost the asset's lifetime, which is projected to reach 30 years in 2050.

Modular manufacturing and automated installation capabilities can drastically cut down on system setup time to few weeks from current ~3 months, as demonstrated by TESLA.

Round-trip efficiency is already rather high and the improvement in system performance will therefore be minimal in the future. Internal losses depend on advancements in battery chemistry and R&D in cell materials; materials will also affect the performance of power electronics, whose efficiency could improve by some % in the next years due to better-engineered solid-state converters.

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

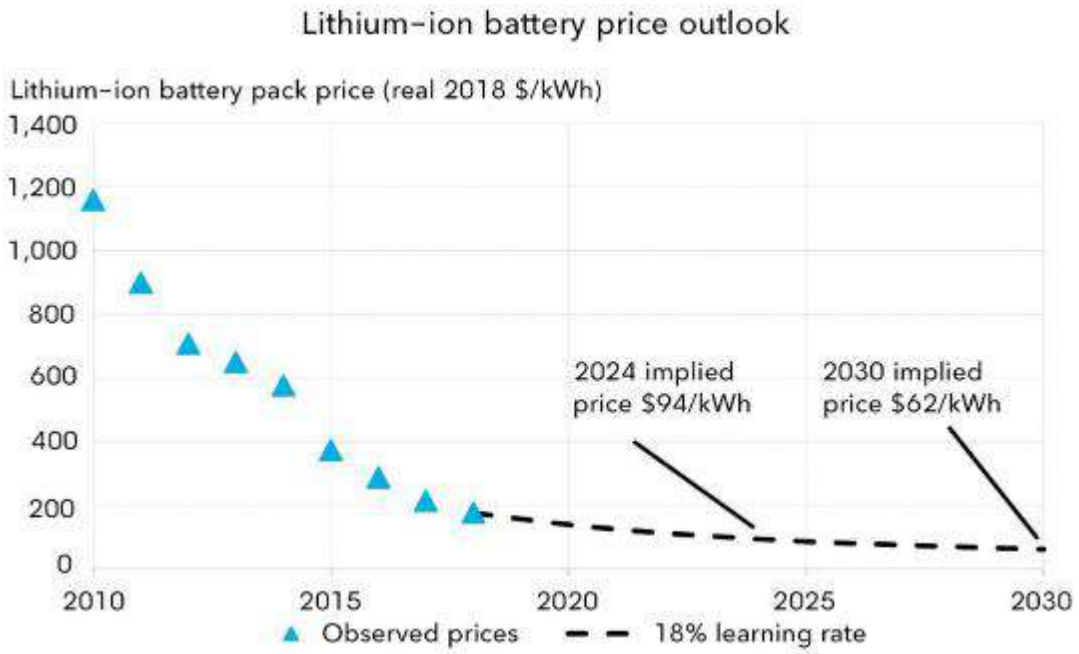


Figure 83: Li-Ion battery pack price projections. Source: Bloomberg NEF.

The price of a small-size battery storage such as TESLA's *Powerwall* (13.5kWh/7kW unit, 0.5 C-rate) can be assumed to be around 500 USD/kWh in 2020, which excludes hardware and installation costs. Figures are lower for bigger storage units.

Lazard's Levelised Cost of Storage report estimates O&M costs to lie in a wide range (0.3-5 USD/kWh). These include both fixed and variable O&M. When costs are calculated for the asset's lifetime, O&M can account for between 1/4 and 1/3 of the Levelised Cost of Storage (ref. 34). Although module costs will decrease, counterbalancing effects from more expensive engineering and further automation would keep installation costs and O&M costs at a similar level or even slightly higher.

Similar to the semiconductor industry, improvements in LIB have been exponential (ref. 35), with price reductions of ~15%/year. Demand from EV and electronic industry have contributed to the accelerated development of the manufacturing industry and of the supply chain. Further improvements came from the R&D knowledge in high-performance materials reaching commercial status. It is assumed that energy density will improve in 2030 by ~30-50% due to R&D efforts put into the battery materials.

Data presented in the data sheet are from specific cases and publicly available sources. Better-negotiated prices are most possibly accessible to project managers. Uncertainty in future development of technology and commercialization affect the accuracy of the suggested numbers for LIB energy storage systems.

Investment costs [$MUSD_{2019}$/MW]	**2018**	**2020**	**2030**	**2050**
New Catalogue (2021)		**0.76**	**0.43**	**0.20**
Danish technology catalogue		0.76	0.43	0.20
NREL ATB		0.86	0.48	0.36
Lazard	0.63			

Note: values for 2-hour storage.

The data in the existing catalogue (2019) was given for another configuration of battery storage (other energy/power ratio) and is therefore difficult to compare to the new catalogue.

Uncertainty in future data
Development in LIB has been rapid in the last few years and upgrades in manufacturing capacity and technologies have been astounding. This is aided by the explosion of the requirements in the area of EV and portable electronics. Large R&D efforts are accelerating the progress, unlike any other storage technologies. For example, development in 6V capable electrolytes, vanadate cathodes and silicon-based anodes can increase the electrochemical potential by 70% and Li-capacity by 3 times – leading to 5-fold increases in the energy density, but these technologies are many years from commercialization. In addition, a polymer gel electrolyte-based battery has been developed that has a cycle life of 200,000 at 96% efficiency (ref. 36). Commercialization of such technology can make LIB systems last for centuries.

Examples of current projects
According to the IEA, at the end of 2018 8 GW of battery capacity were installed worldwide, with 3 GW added only in 2018 (the figure includes all types of batteries)[16]. Many energy storage systems provide system support by participating in frequency regulation services. An example of a large such installation is the Hornsdale battery in Australia. Technology providers include TESLA, A123 systems, LG Chem, BYD, Toshiba, Samsung SDI.

- Hornsdale TESLA battery in Australia. 129MWh/100MW, with an expansion in the pipeline of additional 64.5MWh/50MW. The facility provides mainly system support in the frequency regulation market, but also bulk energy services.
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- Samsung SDI/GE. 30 MW and 20 MWh (black start and frequency regulation). Imperial Irrigation District, El Centro, California, USA. From 2016.
- Toshiba. 40 MW and 40 MWh (bulk energy service for RE). Minamisoma, Fukushima Prefecture, Japan. From 2016.

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



Figure 84: Picture of the 40 MW and 40 MWh energy storage system in Fukushima, Japan (Ref. 48).

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Data sheets

The following pages content the data sheets of the technology. All costs are stated in U.S. dollars (USD), price year 2019. The *uncertainty* it related to the specific parameters and cannot be read vertically – meaning a product with lower efficiency do not have the lower price or vice versa.

Technology	**Batteries - Lithium-ion (utility-scale)**								
US$2019	**2020**	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data				**Lower**	**Upper**	**Lower**	**Upper**		
Energy storage capacity for one unit (MWh)	6.0	7.0	8.0					A,B	1,2
Energy/Power ratio (hours)	1.04	2.08	4.16					E	1,2
Discharge time (hours)	1.00	2.00	4.00					E	1,2
Round-trip efficiency (%) AC	91	92	92					C	3,12
Round-trip efficiency (%) DC	95	96	96					C	3,12
Self-discharge rate (%/day)	0.10	0.10	0.10						4
Forced outage (%)	0.38	0.35	0.25					M	
Planned outage (weeks per year)	0.20	0.10	0.10					L	
Technical lifetime (cycles)	10000	15000	20000					M	5
Technical lifetime (years)	20	25	30					D	
Construction time (years)	0.20	0.20	0.20						
Energy density (Wh/kg)	150	200	300						
Ramping configurations									
Response time from idle to full-rated discharge (ms)	50	50	50						6
Financial data									
Nominal investment (MUSD/MWh)	0.578	0.264	0.157	0.455	0.920	0.075	0.398	G	13
- energy component (MUSD/MWh)	0.152	0.062	0.035	0.080	0.215	0.030	0.131		7,8
- power component (MUSD/MW)	0.311	0.184	0.069	0.273	0.580	0.045	0.284	H	9,10,11
- other project costs (MUSD/MWh)	0.115	0.110	0.105	0.102	0.125	0.023	0.125	N	9,12
Fixed O&M (USD/MWh/year)	621	311	155	500	650	250	350		12
Variable O&M (USD/MWh)	2.30	2.07	1.84	0.45	6.36	0.34	2.84	I	10
Technology specific data									
Energy storage expansion cost (MUSD/MWh)	0.267	0.163	0.086	0.182	0.294	0.052	0.200	B,F	7,8
Output capacity expansion cost (MUSD/MW)	0.311	0.184	0.069	0.273	0.580	0.045	0.284	B,F	9,10,11

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Notes:

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

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

C The gradual change towards lower C-rates following the transition from frequency regulation to renewable integration promotes lower C-rates. Therefore, the average DC roundtrip efficiency is expected to increase slightly. The RT eff. vs. C-rate is exemplified in Figure 7 [3,51]. The AC roundtrip efficiency includes losses in the power electronics and is 2-4% lower than the DC roundtrip efficiency. The total roundtrip efficiency further includes standby losses making the total roundtrip efficiency typically ranging between 80% and 90% [21,22].

D Samsung SDI 2016 whitepaper on ESS solutions provide 15-year lifetime for current modules operating at C/2 to 3C. Steady improvement in battery lifetime due to better materials and battery management expected. Number of cycles can be a more meaningful lifetime indicator.

E The discharge time is the amount of hours the battery can discharge at rated output capacity. It equals the Energy/Power ratio corrected for the discharge efficiency.

F Since multi-MWh LIB systems are scalar, the energy and output capacity expansion costs are here estimated to be equal to the energy and output capacity components plus the “other costs”

G Power conversion cost is strongly dependent on scalability and application.

H The gradual change towards lower C-rates following the transition from frequency regulation to renewable integration promotes lower C-rates. Therefore, the average DC roundtrip efficiency is expected to increase slightly. The RT eff. vs. C-rate is exemplified in Figure 7 [3,51]. The AC roundtrip efficiency includes losses in the power electronics and is 2-4% lower than the DC roundtrip efficiency. The total roundtrip efficiency further includes standby losses making the total roundtrip efficiency typically ranging between 80% and 90% [21,22].

I Cost per MWh of energy discharged from the battery

L It is expected not to have any outage during lifetime of the grid-connected LIB. Only a few days during the e.g. 15 years life time is needed for service and exchanging fans and blowers for thermal management system and power conversion system. Forced outage is expected to drop with increasing robustness following the learning rate and cumulated production. Planned outage is expected to decrease after 2020 due to increased automation.

M Cycle life specified as the number of cycles at 1C/1C to 80% state-of-health. Samsung SDI 2016 whitepaper on ESS solutions provide 15 year lifetime for current modules operating at C/2 to 3C [14]. Steady improvement in battery lifetime due to better materials and battery management is expected. Kokam ESS solutions are also rated at more than 8000-20000 cycles (80-90% DOD) based on chemistry [3]. Thus, for daily full charge-discharge cycles, the batteries are designed to last for 15-50 years if supporting units are well functioning. Lifetimes are given for both graphite and LTO anode based commercial batteries from Kokam. Cycle lives are steadily increasing over last few years as reflected in 2020/2030 numbers [4,5,14].

N Other costs include construction costs and entrepreneur work. These costs heavily dependent on location, substrate and site access. Power cables to the site and entrepreneur work for installation of the containers are included in other costs. Therefore, other costs are assumed to – roughly – correlate with the system size. Automation is expected to decrease other costs from 2030 and onwards.

Examples for calculation of CAPEX using datasheet:

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

CAPEX: 2 * (0.152 M$ + 0.115 M$) + 8 * 0.311 M$ = 3.022 M$

2. Energy integration in 2030: ¼C-rate, 16 MWh BESS system. 25 years operation time.
Cost items:
16 MWh “energy component”, year 2030
16 MWh “other project costs”, year 2030
¼C= 4-hour discharge time ⇒ 4 MW “power component”, year 2030

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

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%). Some of the exceptions are municipal solid waste generation facilities and geothermal power plants, which are designed for continuous operation, i.e. approximately 8000 full-load hours annually (capacity factor of 90%).

Each technology is described by a separate technology sheet, following the format explained below.

Qualitative description

The qualitative description describes the key characteristic of the technology as 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).

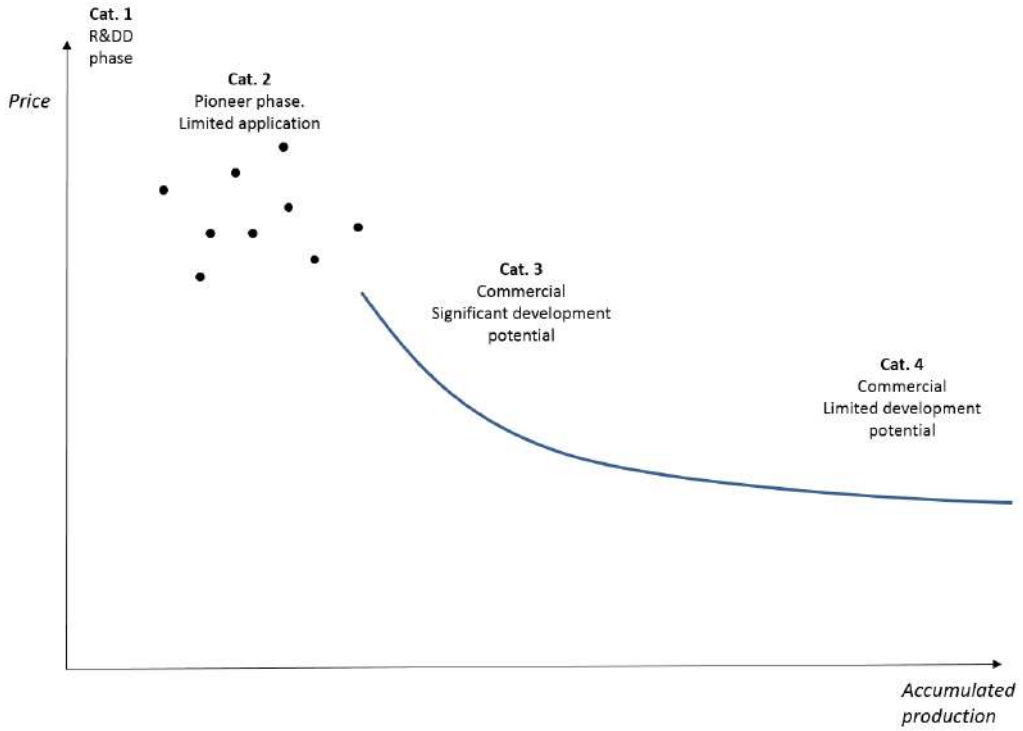


Figure 85: Technological development phases. Correlation between accumulated production volume (MW) and price.

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

Where applicable, cost projections based on the learning curve approach is added at the bottom of the table to show cost trends derived from the application of the learning curve approach (see Appendix 2 for a more detailed discussion). Technological learning is based on a certain learning rate and on a capacity deployment defined as the average of the IEA's Stated Policies and Sustainable Development. The single technology is given a normalized

cost of 100% in 2020 (base year); values smaller than 100% for 2030 and 2050 represent the technological learning, thus the relative cost reduction against the base year. An example of the table is shown below.

Investment costs [MUSD$_{2019}$/MW]		2018	2020	2030	2050
Catalogues	**New Catalogue (2021)**				
	Existing Catalogue (2019)				
Vietnam data	Local data I				
	Local data II				
International data	Danish technology catalogue				
	IRENA				
	IEA WEO 19				
Projection	Learning curve – cost trend [%]				

As for the uncertainty of investment cost data, the following approach was followed: For 2020, the lower and upper bound of uncertainty are derived from the cost span in the various sources analysed. For 2050, the central estimate is based on a learning rate of 12.5% and an average capacity deployment from the STEPS and SDS scenarios of the World Energy Outlook 2019 (see Appendix 2: Forecasting the cost of electricity production technologies). The 2050 uncertainty range combines cost spans of 2020 with the uncertainty related to the technology deployment and learning: a learning rate range of 10-15% and the capacity deployment pathways proper of STEPS and SDS scenarios are considered to evaluate the additional uncertainty. The upper bound of investment cost, for example, will therefore be calculated as the upper bound for 2020 plus a cost development based on the scenario with a learning rate of 10% combined with the scenario with the lowest deployment towards 2050.

Examples of current projects
Recent technological innovations in full-scale commercial operation 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.
Information on general parameters, specifications, fuel or investment capital is obtained from sources such as basic design/ engineering design reports, provided by the power plants, and referenced from project websites. Parameters on characteristics, operating costs, efficiency, and self-consumption are collected from the power system dispatch center (NLDC), from basic design/engineering design reports and provided from power plants. Emission data are obtained from emission measurement reports, basic design/ engineering design reports or from published data of automatic monitoring systems.

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 2019. When converting costs from a year X to $2019 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 2019 using the relationship between the US Producer Price Index for “Engine, Turbine, and Power Transmission Equipment Manufacturing” of year X and 2019 (second table below).

Table 23: The yearly average exchange rate between VND and USD (According to the exchange rate in June of the years of the State Bank of Vietnam).

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.

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

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

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 lower calorific heat value (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.

Net efficiency of a thermal power plant refers to the gross efficiency minus self-consumption.

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, one 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-load hours consider 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 where 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 2019 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, “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 cover buildings, grid connection and installation of equipment.

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

In this report, the intention is that investment cost shall include all physical equipment, typically called the engineering, procurement and construction (EPC) price or the *overnight cost*. Grid connection costs are included, but grid 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 are 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 lifetime are excluded. Reinvestments are discounted at 4% annual discount rate in real terms. The cost of reinvestments to extend the lifetime of the plants may be mentioned in a note if data is available.

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

Fuel costs are not included.

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 does not have the lower price or vice versa. The uncertainty span is evaluated on a case-by-case basis for each technology. For well-developed technologies the uncertainty span is typically lower than for technologies under development.

APPENDIX 2: FORECASTING THE COST OF ELECTRICITY PRODUCTION TECHNOLOGIES

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

Three main different approaches to forecasting are often applied:

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

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

Advantages and disadvantages of different methodologies for forecasting technology costs.

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

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

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

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

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

- The **Stated Policies scenario (STEPS)** assesses the evolution of the global energy system on the assumption that government policies that have already been adopted or announced with respect to energy and the environment, including commitments made in the nationally determined contributions under the Paris Agreement, are implemented;
- The **Sustainable Development scenario (SDS)** describes the broad evolution of the energy sector that would be required to reach the key energy-related goals of the United Nations SDGs, including the climate goal of the Paris Agreement (SDG 13), universal access to modern energy by 2030 (SDG 7), and a dramatic reduction in energy-related air pollution and the associated impacts on public health (SDG 3.9) [8].

We use the average of these two IEA scenarios to set a realistic framework for the future technology deployment.

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

The final projections of electricity generation capacity for 2018 to 2020 as per world energy outlook 2019 data and forecasting done are represented in the figures below. As can be seen, for SDS, the projections estimate a significant increase in renewables like solar and wind, and a reduced dependency on fossil fuels in order to meet the sustainable development goals. It can also be noted that the projected installed capacity in the SDS scenario is higher compared to STEPS. This is due to the fact that technologies like wind and solar have lower capacity factors and therefore more capacity is needed to supply the same demand.

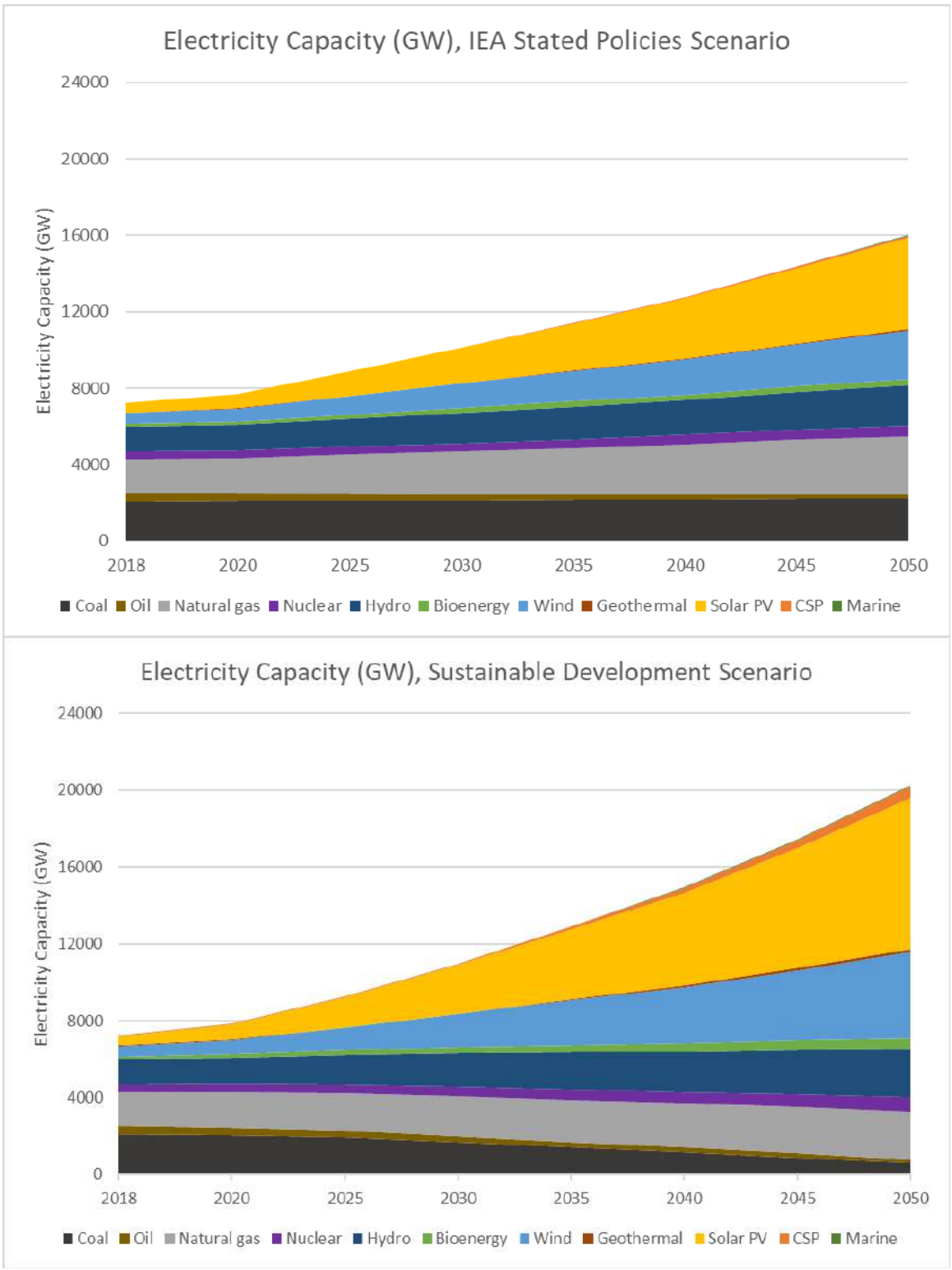


Figure 86: Electricity Capacity (GW) in the IEA's stated policies and sustainable development scenarios. IEA – World Energy Outlook 2019 [9].

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

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

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

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

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

Learning rates

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

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

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

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

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

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

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

Technology cost compared to 2020 (2020 = 100%)		**STEPS**			**SDS**			**Average of STEPS and SDS**		
Technology	**Learning rate**	**2030**	**2040**	**2050**	**2030**	**2040**	**2050**	**2030**	**2040**	**2050**
Coal	12.50%	98%	95%	94%	99%	99%	98%	98%	97%	96%
Oil	12.50%	99%	98%	97%	99%	98%	97%	99%	98%	97%
Natural gas	12.50%	95%	91%	88%	96%	93%	90%	95%	92%	89%
Nuclear	12.50%	96%	93%	90%	96%	92%	88%	96%	92%	89%
Hydro	12.50%	96%	93%	91%	95%	91%	88%	96%	92%	89%
Bioenergy	12.50%	92%	86%	83%	89%	82%	77%	91%	84%	80%
Wind	12.50%	87%	79%	74%	84%	75%	69%	85%	77%	72%
Geothermal	12.50%	89%	79%	74%	84%	72%	67%	86%	75%	70%
Solar PV[17]	20%	73%	61%	55%	69%	55%	48%	71%	58%	51%
CSP	12.50%	81%	67%	62%	78%	56%	48%	79%	62%	55%
Marine	12.50%	77%	59%	56%	74%	57%	52%	76%	58%	54%

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

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

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

Global and regional learning

The learning effects found in this review express a global view on technology learning. Considering that the majority of technology providers today are global players this seems to be a reasonable assumption. Therefore, cost reductions generated in one part of the world will easily spread to the other regions.

Still, in a 2020 perspective Vietnamese prices of some technologies may be higher (or in some cases lower) than

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

international reference values because local expertise is limited. However, as Vietnamese know-how is built up and technologies are adapted to the Vietnamese context within the next decade, it is reasonable to assume that cost will approach the international level.

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APPENDIX 3: HYDROGEN GENERATION AND TECHNOLOGY

Status of application

Hydrogen has gained significant interest worldwide for its potential to displace fossil fuels and abate CO_2 emissions when it is produced from renewable energy. However, today hydrogen is mainly produced from fossil fuels for industrial purposes. In 2018, global demand for hydrogen was roughly 120 Mt corresponding to 14.4 EJ. This makes up around 4% of final energy and non-energy use in the world. Demand has been increasing since 1980 and has grown more than 30% from 2010 to 2018 (see figure below).

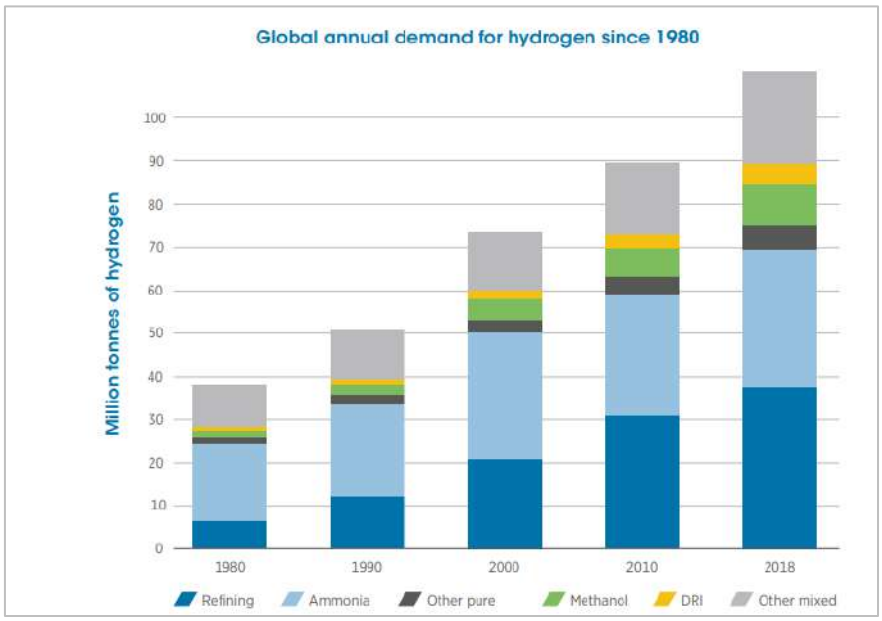


Figure 87. Global annual demand for hydrogen. Source: IEA based on (IRENA, 2019)

The majority of hydrogen consumption today is produced and used on-site in industries. About 70-80% of the hydrogen production is made as the primary product while the remaining part is produced as a byproduct from other industrial processes. The main demand for hydrogen comes from the refining sector (32% in 2018) and ammonia production for fertilizers (27%). Besides these, hydrogen is also consumed for methanol production (8%), iron and steel (3%) and other industrial applications such as semiconductors, propellant fuels, glass production, hydrogenations of fats, cooling of generators and more. (IRENA, 2019) (IRENA, 2018)

Technology development and maturity

Historically, hydrogen has been produced from fossil fuels through thermochemical reactions. In 2018, 95% of global hydrogen production was natural gas and coal based (majority from natural gas) while less than 5% was produced from electrolysis. (IRENA, 2019) The main deployment of electrolysis today comes from the chlorine production where hydrogen is produced as a byproduct. Globally, hydrogen production from renewables is only in its infancy however, the number of projects is increasing rapidly for research and development purposes.

The thermochemical production process depends on the fuel. Hydrogen from natural gas is produced through the steam methane reforming reaction (SMR). From coal it can be produced by gasification of coal. Hydrogen can also be produced from gasification of biomass. However, it is not a very common.

Hydrogen production technologies include:

- Natural gas – steam methane reforming (SMR)
- Coal – Coal gasification
- Biomass – Biomass gasification or biomass-derived liquid reforming
- Water electrolysis
- Direct Solar Water Splitting processes
- Biological processes

(DOE, 2020)

CO_2-neutral hydrogen production

Hydrogen has the potential to substitute fossil fuels and has therefore achieved substantial political focus in the recent years primarily driven by a wish to mitigate climate change. For instance, Japan and South Korea have set ambitions targets for the deployment of hydrogen production and power to X technologies. This potential can only be redeemed when hydrogen is produced in a CO_2-neutral way. The two main CO_2-neutral ways of producing CO_2-neutral hydrogen includes electrolysis-based production from renewable electricity or blue hydrogen production. Blue hydrogen production covers fossil fuel-based production with carbon capture and storage (CCS) such that net CO_2 emission is close to zero.

Electrolysis

The electrolysis technology is an overall process where water is split into hydrogen and oxygen. There are three main technologies with different levels of maturity:

- Alkaline electrolysis
- PEM electrolysis
- SOEC electrolysis

Alkaline electrolysis is a mature and commercial technology. It has been used since the 1920s, especially for hydrogen production in the fertilizer industry and the chlorine industry. A range of alkaline electrolysers are flexibly operated from 10% load to full design capacity. Several alkaline electrolysers with capacities of over 100 MW of electricity were previously established in countries with large hydropower resources (Canada, Egypt, India and Norway). Today, most of these today are outcompeted by hydrogen production based on fossil fuels. Alkaline electrolysis is characterized by relatively low capital costs compared to other electrolysis technologies, e.g. due to the fact that common and inexpensive materials are used.

PEM electrolysis was introduced in the 1960s by General Electric to overcome certain disadvantages of alkaline electrolysers. PEM electrolysers use pure water as an electrolyte solution, thus avoiding the recovery and recycling of potassium hydroxide. On the other hand, the water needs to be purified before being able to be used. They can be relatively small, making them potentially more interesting for specific purposes. They are capable of producing highly compressed hydrogen for decentralized production and storage at service stations (30-60 bar without an additional compressor and up to 100-200 bar in some systems compared to 1–30 bar for alkaline electrolysers). Their operating range can go from zero load to 160% of the design capacity. However, they need expensive electrode catalysts (platinum, iridium) and membrane materials, and their service life is currently shorter than for alkaline electrolyzers. They have higher costs and are less common.

SOECs are the least developed electrolysis technology. SOEC uses ceramic materials as electrolyte and therefore has low material costs. They operate at high temperatures and with a high degree of efficiency. Since steam is used for the electrolysis, a heat source is needed, which contributes to high electricity efficiency.
(IEA, 2020)

Figure 2: Timeline of power-to-hydrogen projects by electrolyser technology and project scale

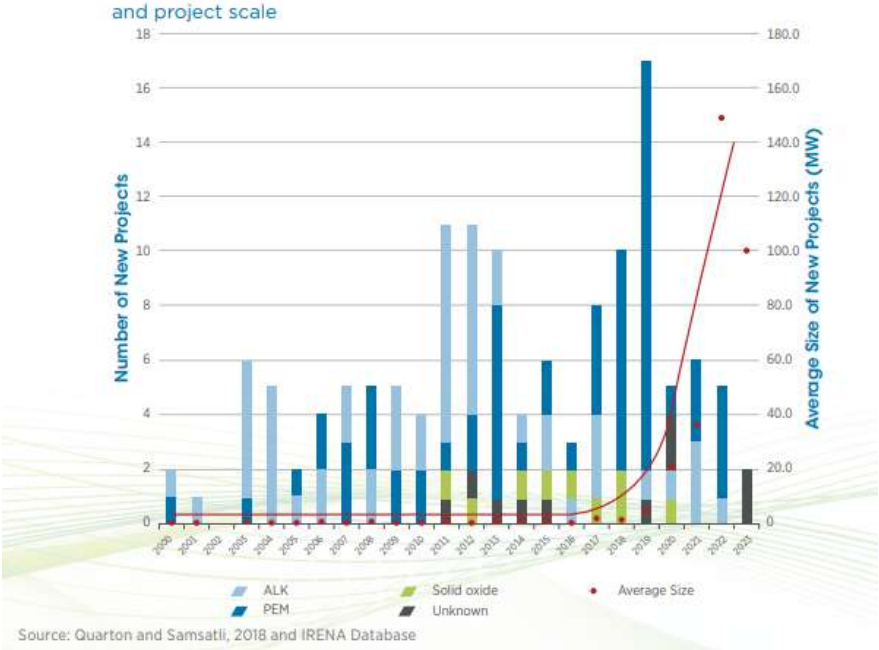


Figure 88. Timeline of power-to-hydrogen projects by electrolyser technology and project scale. Source: (IRENA, 2019)

The deployment of electrolysis is limited but several countries have developed strategies for how hydrogen, carbon capture and storage and PtX can contribute to the green transition and business development. This includes EU, Japan, South Korea, France, Germany, Norway, the Netherlands and more.

Future hydrogen consumption
Besides the significant global demand for hydrogen for traditional purposes (mainly refining and fertilisers), a new hydrogen demand is expected to arise due to the need for alternative fuels to mitigate climate change. It is essential that this future demand for hydrogen is supplied from sustainable and renewable sources.

Hydrogen has potential to be used either directly in the transport sector or to be applied in fuel cell vehicles. Especially in the hard-to-transit sectors like heavy duty vehicles or long-distance busses, hydrogen and fuel cells could play a role if it is cost effective compared to other green alternatives. By 2030, Japan aims to produce 300,000 tons of hydrogen annually (corresponding to 36 PJ) and they have a target to increase the number of fuel cell vehicles to a total of 800,000.

Moreover, hydrogen could also be used as input to produce a variety of other products through the power to X technologies. Power to X covers a range of technologies where renewable hydrogen is used in combination with for instance CO_2 and nitrogen to produce gaseous or liquid fuels such as methane, methanol, ammonia, syndiesel and sustainable aviation fuel.

The key to low hydrogen production costs from electrolysis is low electricity prices from renewable resources.

Perspectives for further studies
Further studies could include:

- Mapping existing hydrogen consumption in Vietnam
- Technology and economic data for hydrogen production capacity in Vietnam including with focus on electrolysis technology
- Perspectives for hydrogen to substitute fossil fuels in Vietnam
- Potentials and costs of Power to X production in Vietnam

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